Gas Mobility during Three Phase Flow in a WAG Process

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ABSTRACT

The main objectives of the work presented in this paper was to determine the influence of saturation history, fluid/rock interaction (wettability), fluid interfacial tensions and capillary pressure on gas mobility during three phase flow in combined gas/water injection processes (CGW, WAG or tertiary gas injection). The paper will give results from three different experimental studies performed within the RUTH and SPOR programs as well as a WAG study on a Norwegian Oil Field. The work includes three-phase flow experiments in three different outcrop sandstones Bentheimer, Berea and Fontainebleau (length 50 to 75 cm), while the reservoir rock was a 60 cm long composite sandstone core. Experiments on the outcrop sandstones were performed at low pressure and temperature, while the experiments on the reservoir rock were performed at the specific conditions of the reservoir.

The outcrop sandstones were initially water wet while the reservoir core was anticipated to be mixed wet. All cores were investigated for heterogeneity by CT-scanning. The mineralogy of the reservoir cores and the Bentheimer and Berea sandstones were determined. Thin section analysis were used for defining the pore characteristics. Except for the Berea core, all porous medium were fairly homogeneous with little content of clay minerals, but with different properties with respect to pore characteristics. This was also the case for the reservoir core.

Three-phase relative permeabilities were measured by steady state and displacement methods. In unsteady state displacement experiments with gas, the recovery of oil was found to be lower at non-spreading than at spreading conditions. The mobility to gas was also lower. When gas was flowing together or alternating with water at high water saturations, the mobility was extremely much smaller than for a similar two-phase situation. This difference was more pronounced for Berea than for Bentheimer and Fontainebleau sandstone. This can be explained by the large difference in pore properties of the different porous media. These observations were confirmed by the reservoir conditions experiments, i.e. the mobility of gas is much smaller than what can be assumed for three phase flow based on standard gas/liquid two-phase relative permeability measurements.

INTRODUCTION

The work presented in this paper is basically performed within the Norwegian research programs SPOR and RUTH¹⁻³, and is focusing on the topic of gas mobility the key factor for the performance of WAG or tertiary gas injection process.

Even though the problem of three-phase flow has been addressed by several researchers during the past, it is still not established sufficiently accurate and predictive techniques for handling three-phase flow under the different possible modes of flow.

One of the major reasons for this is the complexity of handling the hysteresis of relative permeability and capillary pressure as functions of saturation and saturation history. This latter topic can be considered as the main challenge in the modelling of multiphase flow and unless the handling of saturation history is improved considerably, it is not likely that much improvement can be made in flow predictions.

In the secondary saturation history mode altogether 27 different saturation histories can be achieved in a three-phase system, and when knowing that several of these incorporate heavy hysteresis for increasing and decreasing saturation of a certain phase, the picture gets even more complex. This will typically be the case in WAG and tertiary gas injection processes.

The objectives of the work presented in this paper were to study the effects of wettability, spreading and hysteresis on gas mobility in particular, which is the key issue in a WAG or tertiary gas injection process. Within the RUTH Combined Gas/Water subprogram a series of long core experiments have been carried out in water-wet outcrop sandstones, Fontainebleau and Clashach, under spreading and non-spreading conditions as well as Berea sandstone rendered oil-wet by silanization. These cores are long, fairly homogeneous cores with little or no content of clay minerals (except for the Berea), but with different properties with respect to pore characteristics. Three-phase relative permeabilities were measured by the steady state method under spreading and non-spreading conditions. Two sets of water/oil systems had to be used to obtain this spreading and non-spreading behaviour.

Drainage (increasing gas saturation) and imbibition (increasing oil saturation) relative permeabilities for the gas/oil system in presence of an irreducible water saturation were measured by the steady state technique. Then following this series of experiments, displacement experiments were carried out in which recovery vs. time was recorded as well as local saturation by CT-scanning of the cores in dual energy mode. Due to the limiting space in this paper, the results of the displacement experiments will not be presented in this paper.

The same type of measurements were carried out in a Berea sandstone which was rendered oil wet by silanization. In addition to this, several steady state experiments have been carried out in which the effect of liquid saturation (water and oil) on

gas relative permeability have been studied out in water-wet Bentheimer sandstone.

We have also performed some measurements in a reservoir system at reservoir conditions in which two cycles of water and gas were injected. In this process gas mobility was measured as a function of gas saturation.

In the following sections we will look further into the problems of gas mobility during three phase flow through the results of the obtained experimental work. We will start with some theory regarding the most important factors affecting gas mobility, and then discuss the results in the context of WAG. Finally, we will come up with some concluding remarks with recommendations regarding how to handle gas mobility in reservoir evaluation. Though, the latter will be based on our overall knowledge within the field.

BACKGROUND

Gas mobility is the key factor for the success of a WAG or a tertiary gas injection process. It is consequently of utmost importance to have a complete understanding of this topic in order to properly handle the flow of gas during such processes.

There are several factors that govern the flow of fluids through porous medium: Geometric factors (permeability, porosity and heterogeneity); viscous forces (pressure gradients and viscosity); gravity forces (differences in density); fluid/fluid interaction (interfacial tension, spreading and adsorption); and fluid/solid interaction (mineralogy, surface adsorption and wettability). In the discussions that follow we will concentrate on some of the factors that influence capillary pressure and relative permeability: interfacial tension (capillary pressure), spreading and wettability.

Capillary pressure¹. Three-phase flow properties are closely related to the capillary pressures acting in the porous medium. In the standard framework, these capillary pressures are assumed to be similar to the two-phase data. The two liquids, oil and water, are thus assumed to behave as one liquid with respect to the gas phase. Both experimental and theoretical papers have been published¹¹ to confirm this assumption but, at least for the experimental data, they are not convincing with regard to the high discrepancy of the measurements.⁹

For two-phase flow in porous medium, the capillary pressure, P_c is defined as the difference between the two fluid pressures. During drainage, for a given pressure difference, oil/water menisci are located at the entry of pores with throat radius equal to R . The amount and the distribution of this set of radii determine a saturation S for which the capillary pressure is equal to $2\gamma\cos\theta/R$, θ being the angle formed by the meniscus and the solid wall.

For three-phase flow in porous medium, the capillary pressure has to depend on the contact angle, as well. For a strongly water wet core, this contact angle, θ , can be defined by the three interfacial tensions γ_{wg} , γ_{og} and γ_{ow} involved in the system. This contact angle is related to a liquid/liquid wettability¹⁰⁻¹² and is more directly associated with the spreading coefficient S which is defined as the balance between the three interfacial tensions according to (water-wet porous medium, see Figure 1):

$$S = \gamma_{wg} - (\gamma_{og} + \gamma_{ow}) \quad (1)$$

A positive spreading coefficient means that the force per unit of length pulling the triple line, the interfacial tension γ_{wg} , is dominant when compared to the sum of the γ_{ow} and γ_{og} . A positive spreading coefficient leads thus to the total spreading of an oil droplet on a water film in presence of gas. On the other hand, a non-spreading coefficient leads to an equilibrium shape for the gas/oil meniscus thereby defining an equilibrium contact angle θ , related to the spreading coefficient by:

$$\cos\theta = 1 + \frac{S}{\gamma_{og}} \quad (2)$$

The contact line between the oil droplet and the water film reduces then to one point when the spreading coefficient becomes less than $-2\gamma_{og}$. For an oil-wet system similar expressions can be written.

Therefore, three-phase flow capillary pressures should depend on the spreading coefficient through the contact angle. This is clearly shown in Figures 2 and 3 which show scaled capillary pressures between gas and oil at spreading and non-spreading conditions in water-wet and oil-wet porous medium, respectively. Equations (1) and (2) assume a flat surface, and a flat wetting/non-wetting liquid interface.

Figure 1 Spreading and non-spreading in water-wet gas-oil-water-solid system.

By use of pore scale experiments, the role of the spreading coefficient during both drainage and imbibition can be enlightened as follows:

Drainage:

- The spreading coefficient has been clearly related to the value of the contact angle (Figure 1). This coefficient thus models the wettability of the system of fluids.
- The spreading coefficient has been shown to influence the residual oil saturation. As soon as it becomes negative, the pressure level which is necessary to drain an oil pocket, is doubled because of the impossibility for the oil phase to exit by films. This is an explanation of observed high residual oil saturations for a system of fluids with a negative spreading coefficient.

Imbibition:

- Pore scale experiments have shown that a water flood efficiency in presence of a gas bubble, depends on the spreading coefficient. When it is positive, the applied pressure necessary to displace oil by water, corresponds to the Laplace value. When it is negative, film flow is not allowed for the oil phase. Therefore, an extra pressure has to be exerted in the water phase. This leads to a change in the curvature of the water/oil meniscus. This is an explanation to the negative capillary pressures observed during imbibition performed in a rock sample, in presence of a trapped gas saturation and with a slightly negative spreading coefficient.

Figure 2 Gas-oil capillary pressure in water-wet high permeability sandstone core.¹

Figure 3 Gas-oil capillary pressure in oil-wet high permeability sandstone core.¹

It is thus necessary to come up with three-phase capillary pressure definitions accounting for three-phase flow mechanisms and in particular the spreading coefficient. During drainage, as the capillary pressure threshold and the residual oil saturation have been shown to depend on the spreading coefficient, the following expression has been proposed for a drainage capillary pressure in presence of connate water saturation:

$$P_c = P_{c0}(S) + S_g' \alpha \quad (3)$$

$$\text{with } S_g' = \frac{S_g}{1 - S_{wirr} S_{org}}$$

For imbibition in presence of a trapped gas saturation, a similar equation could be proposed. However, more data have to be collected to verify the above equations for three phase conditions.

Three-phase film flow at different wetting conditions.^{10,13,14} As the three-phase capillary pressures are depending on the spreading conditions so are also the relative permeabilities. A very important mechanism during three-phase flow is flow through films. Fluid-solid (wettability) and fluid-fluid interactions (spreading coefficient) affect the distribution, mobility and displacement mechanisms in three-phase systems. The presence of continuous wetting and spreading films allows the three phases to flow simultaneously, while in absence of spreading films only two of the phases can flow simultaneously in the same pore space.

The distribution and mobility of the phases determine the progress of a three-phase displacement. A typical displacement sequence can be divided into the following steps:

- (i) Flow of non-wetting phase injection fluid (gas) from the inlet to the displacement site.
- (ii) Displacement of the intermediate (oil or water) or wetting phase (oil or water) by the non-wetting phase (first drainage event).
- (iii) Flow of the displaced wetting phase to the outlet, or flow of the displaced intermediate phase (oil or water) to the site of the second drainage event.
- (iv) Displacement of the wetting phase by the intermediate phase (second drainage event).
- (v) Flow of the displaced wetting phase to the outlet.

The intermediate phase is always displaced by a double drainage mechanism ((ii) and (iv)). The wetting phase may be displaced by the double drainage mechanism when the intermediate phase forms continuous spreading films and/or by a direct two-phase mechanism in absence of continuous spreading films. In either case, for the displacement to proceed, two conditions must be satisfied:

1. Capillary pressure must exceed the controlling throat threshold pressure.
2. Flow paths for the displaced intermediate (iii) and wetting (v) phases must have sufficient capacity to allow the necessary volumes of fluid to be transported away from the displacement site.

The fluid carrying capacity of possible flow paths depends on the thickness of wetting films, the presence or absence of intermediate spreading films and geometric (topological) effects. Geometric (topological) effects depend on phase saturations and determine the length (resistance) of film flow paths and the ease with which the intermediate phase may be reconnected.

This suggests that the oil wetting films are much thicker and more conductive than the oil spreading films for the spreading system under strongly water-wet conditions. The cross-sectional area available for flow through oil spreading films in a micro model is approximately 0.15% of the total pore cross-sectional area. The corresponding area for oil wetting films is approximately 5.4%¹⁰, i.e. higher conductivities of the oil wetting films. Oil recovery is, of course, lowest for the non-spreading system under strongly water-wet conditions where there are no oil films at all. Water wetting films play a similar role to oil wetting films and water recoveries for the water-wet displacements are high and of similar magnitude to oil recoveries for the oil-wet displacements.

The implications of the discussions above are that gas flooding under strongly oil-wet conditions may be more effective and less difficult to design than under strongly water-wet conditions. This is because;

- (i) oil wetting films may be thicker and more conductive than oil spreading films for spreading systems under strongly water-wet conditions;
- (ii) under strongly oil-wet conditions the water phase blocks the progress of gas fingers and this improves local sweep efficiency,
- (iii) whereas oil recovery under strongly water-wet conditions depends on the sign of the spreading coefficient, recovery under strongly oil-wet conditions is insensitive to the sign of the spreading coefficient.

Effects of wettability on three-phase relative permeability.^{4,8} Relative permeability of a wetting phase depends most strongly on the saturation of that phase. Hysteresis (separation of primary and secondary relative permeability curves) is usually a minor factor for a wetting phase.

Relative permeability of a non-wetting phase (most often gas) depends most strongly on the saturation of that phase and on the saturation history of that phase. Hysteresis between primary and secondary cycles is often large, and dependence on the saturation history of the other phases may also be an important factor.

Relative permeability of an intermediate-wetting phase (oil, in the water-wet tests; water, in the oil-wet tests) may show hysteresis; there may also be a significant dependence on the saturation of the other phases.

The surface formed in the ternary saturation/relative permeability space for each phase is generally smooth. For a strongly wetting or non-wetting phase the data surface is "flat" in the direction nearly parallel to lines of constant saturation of that phase.

For an intermediate-wetting phase the surface may be curved. In the tests reported by Baker⁴, the relative permeability surface for oil in the water-wet cores is concave toward the prism vertex corresponding to 100% oil saturation. The curvature is reduced in the intermediate-wet and oil-wet cores, as the degree of oil-wetting increases. The curvature of the water relative permeability surface is not very pronounced in either the intermediate-wet or oil-wet cores, but the influence of gas and oil saturation on the water relative permeability increased as the porous medium became more oil-wet.

Linear interpolation between curves obtained from two-phase tests can give a good estimate of phase relative permeability in the three-phase flow region. This is true when the relative permeability surface is "flat", as for the water and gas phases. Stone's method 1 predicts reasonable values of oil relative permeability for the water-wet case, where the relative permeability surface is curved, but linear interpolation is better for the intermediate-wet and oil-wet cases.

MEASUREMENTS OF GAS RELATIVE PERMEABILITY AT SPREADING AND NON-SPREADING.

Three-phase relative permeabilities were measured by the steady state method and unsteady state displacement under spreading and non-spreading conditions (i.e. oil spreads on water or it does not spread on water in presence of gas). Both of these techniques are standard techniques and do consequently not need any specific introduction. Two sets of water/oil systems had to be used to obtain this spreading and non-spreading conditions. Spreading was obtained by the fluid pair: Isopar M oil ($\mu_o=2.2$ cP), and brine (25 g/l BaCl₂, $\mu_w=1.02$ cP), and non-spreading by the fluid pair Soltrol 170 oil ($\mu_o=2.72$ cP) and brine (30 g/l CaCl₂ + 1 % Isobutanol, $\mu_w=1.11$ cP). In both cases nitrogen was used as gas phase.

In unsteady state displacement experiments of oil by gas for water-wet cores the recovery of oil was found to be lower at negative than at positive spreading. This difference was more pronounced for the Clashach than for Fontainebleau sandstone, which can be explained by the large difference in pore properties of the two porous media. This difference is primarily due to the difference in relative permeability. Unsteady state relative permeabilities were lower at negative than at positive spreading. This was specifically the case for low saturations and for the gas phase.

Figure 4 Relative permeability of oil and gas as a function of gas saturation in spreading and non spreading conditions in water-wet Fontainebleau sandstone.^{1,2}

In the steady state experiments on water wet cores the obtained relative permeabilities for both oil and gas were lower for $S<0$ than $S>0$. The relative permeability to gas for $S<0$ was extremely low except for the final point during oil drainage due to excessive equilibration time. Steady state relative permeabilities were higher than unsteady state curves at negative spreading. For the gas phase this was the case irrespective of spreading. For positive spreading the difference is within experimental uncertainty. The obtained relative permeability curves for the Fontainebleau sandstone are shown in Figure 4 for the steady state experiments.

In the oil-wet case of the Berea sandstone ($k_{abs}=700$ mD, rendered oil-wet by silanisation) the steady state experiments show the same trend as for the water wet core, except, of course, that the relative permeability to oil as the wetting phase is much smaller. To a certain extent this is also the case for the gas, but this can be due to the characteristics of the porous medium and its pore size distribution. The results of the experiments in the Berea sandstone are shown in Figure 5.

Figure 5 Relative permeability of oil and gas as a function of gas saturation at spreading and non spreading conditions in an oil-wet Berea sandstone.

Since both cores are oriented horizontally (due to application X-ray CT for in-situ saturation measurement with emphasis on gas saturation) the end point saturation of oil may not be the minimum oil saturation obtainable. This may strictly be a geometric effect due to the experimental set-up and not an effect attributed to the flow mechanism of

the porous medium. The cores have relatively high permeability and it is consequently expected a higher oil production if the cores are oriented vertically.

From the above measurements it can be concluded that there are clearly an effect of the spreading properties since the non-spreading case was one order of magnitude lower in relative permeability close to the residual saturation. Regarding the residual saturation itself, it seems that it is somewhat lower than for the spreading than for the non-spreading case. This is of course not surprising since spreading promote film flow which will drain the oil better at least for the water-wet case.

EFFECT OF MOBILE WATER ON GAS RELATIVE PERMEABILITY.

The experiments reported previously in this paper have been performed at irreducible water saturation (S_{wi}). Once all three phases are mobile which will happen at an incremental increase in water saturation above S_{wi} , the gas mobility is drastically decreasing with k_{rg} below 10^{-5} . In order to avoid problems with segregation of gas and water in a WAG process, it may be important to keep the water saturation mobile. This can be achieved by small WAG cycles (high WAG frequency) or by simultaneous injection of water and gas.

The effect of a mobile vs. a non-mobile water saturation can be seen in Figure 6. This figure shows the gas relative permeability vs. gas saturation for gas/oil two-phase flow and for gas/oil/water flow at increasing, decreasing and increasing saturations of water, oil and gas, respectively (IDI, defined in several papers^{4,7}); and for 3-phase DDI. These measurements were performed by the steady state technique at 10 bar and room temperature in order to reduce the effect expansion of gas due to ΔP . In-situ saturation measurements were used to keep track of the gas saturation. In these experiments the $S_{wi} < S_w$ throughout the experiments. The oil/water ratio was approximately 1:1 for the DDI case. The spreading properties have not been measured, but it is assumed to be slightly positive since the system consisted of nitrogen, decane and 3 weight% NaCl brine. As can be seen from Figure 6 the gas relative permeability is much lower for three-phase flow than for two-phase flow. Extreme care should consequently be taken before two-phase gas relative permeability is used for three-phase calculations.

Figure 6 Gas relative permeability vs. gas saturation for two- and three-phase flow.

A series of displacement experiments were performed on a reservoir system from the North Sea at reservoir conditions. In the experiments two cycles of water and gas were injected. In this process the gas mobility was measured as a function of gas saturation. The results of these measurements are given in Figure 7. The figure clearly shows that there are effects of saturation history on the value of gas relative permeability which is considerably reduced from primary to secondary cycles with gas in addition to have considerable hysteresis in the curves.

Figure 7 Gas relative permeability vs. gas saturation for WAG-process in reservoir cores, $S_{or}=2\%$.

The gas relative permeability is very low, even for high gas saturations. In this case the spreading properties is not measured, but most real reservoir systems have positive spreading, and the current system is therefore regarded as spreading since the gas is first contact miscible with the oil with corresponding low IFT between gas and oil. In this specific case the residual oil saturation approached zero.

The wetting characteristics are mixed wet, but this will not influence the gas relative permeability since gas will be non-wetting and the spreading is positive.

SUMMARY AND RECOMMENDATIONS

In this paper the major results of different capillary pressure and relative permeability measurements have been discussed. From the discussions above it should be clear that the topic of three-phase flow in porous medium is not trivial.

Key factors are wettability and hysteresis (saturation history) because these clearly define the distribution and residual saturations of fluids at well as the mobility of these fluids at functions of saturation and saturation history. Wettability can not be measured directly in the reservoir, but from laboratory measurements qualitatively the wettability can be determined. Techniques are under development that may define wettability vertically throughout the producing zones of the wells. This, in combination with measurements of fluid composition and pore-wall mineralogy, enable us to more precisely quantify the wettability. Once the wettability and spreading properties have been established, one knows which types of relative permeability curves to use.

Finally, but not least as have clearly been demonstrated from our experiments, it is necessary to evaluate the saturation histories that will take place, and then incorporate the hysteresis effect following that type (or types) of saturation history. In case there are experimental three-phase data available for the actual conditions, these should be given high priority in the establishment of which three-phase relative permeability curves to be used.

In an oil-wet system or a system in which oil spreads on water, the oil saturation should be permitted to approach zero or at least saturation levels below what traditional two-phase water/oil relative permeability curves show even though the

values may be extremely low for a considerable saturation range.

Whether to use a model like Stone I or experimental data in a tabular form, is not important as long as the model reflects the physics of the process in question and are tuned to experimental data which are properly scaled. If relevant experimental data can be used this is nevertheless highly recommendable, since it is well known that available models are not yet good predictive tools. Though, use of experimental data often causes practical problems since the numerical simulators often do not permit tabular input of three-phase relative permeability in a sufficiently detailed manner.

It is important to keep in mind that the failure of a WAG injection (early breakthrough of gas and water, or segregation) not necessarily is due to poor handling of three-phase relative permeability in the reservoir evaluation process, but that this often is due to poor reservoir description or that improper wells are used for the injection (fractured, low injectivity or misplaced perforations). Of specific importance is the accuracy of the vertical permeability which is a key-factor in the evolution of a WAG or CGW injection process.

NOMENCLATURE

k	= permeability (m^2)
o, w, g	= oil, water and gas phases (subscripts)
R	= Pore or capillary tube radius (m)
S	= saturation
S	= spreading coefficient (mN/m)
S_{wirr}	= irreducible water saturation
S_{org}	= residual oil saturation in drainage
ϕ	= capillary tube diameter
ϕ	= porosity
θ	= contact angle (rd)
$S_{o/w}$	= oil over water spreading coefficient, mN/m
γ_{og}	= oil/gas interfacial tension (IFT)
γ_{ow}	= oil/water interfacial tension (IFT)
γ_{wg}	= water/gas interfacial tension (IFT)

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