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Evaluation of CO_2 and Carbonated Water EOR for Chalk Fields

By

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September 2012

DECLARATION OF OWN WORK

I declare that this thesis

Evaluation of CO_2 and Carbonated Water EOR for Chalk Fields

is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

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Abstract

Modifying the chemical composition of injected water has the ability to increase the ultimate recovery after waterflooding in carbonate reservoirs (Austad et al. 2005; Yousef et al. 2011). The use of carbon dioxide (CO_2) as an enhanced oil recovery (EOR) method has been given considerable attention since it allies reduction of emissions of green-house gases with a high potential for improving oil recovery in maturing reservoirs. CO_2 can be directly injected as a pure compound or as carbonated water by dissolving the CO_2 in brine prior to injection. The development of miscibility between the injected gas and the reservoir oil for both pure CO_2 injection and carbonated water injection (CWI) induces oil swelling and a subsequent oil viscosity reduction that leads to higher recovery. However, compared to conventional CO_2 flooding, CWI has shown a very gradual CO_2 breakthrough which is an advantage. In order to decide which one of these two EOR methods is more appropriate, it is crucial to understand the physical mechanisms involved in the oil recovery process and their relative importance.

This study analyses a set of experiments of pure CO_2 injection and CWI after waterflooding (tertiary recovery) performed at the core scale in order to build a numerical model with a compositional reservoir simulator. After understanding the small scale displacement processes involved by assessing their importance, an alternative methodology to model the CO_2/CWI processes at the core scale is proposed.

The experimental results show that CO_2 and CWI both increase the ultimate oil recovery after waterflooding. Conventional CO_2 injection achieves the increase much faster than CWI because of the mass transfer mechanisms involved in the process. The simulation results demonstrate that the current compositional simulators do not properly capture the dominant production mechanisms and the final recovery is systematically over-predicted. This issue is discussed and partially solved by proposing an alternative method to match the experimental data for pure CO_2 injection. Finally, the importance of wettability changes during the process is raised and a method to include them is presented.

Introduction

Naturally fractured, low matrix permeability, chalk reservoirs usually present a low oil recovery after conventional waterflooding because of the fracture-matrix geometry that allows the injected water to flow through the interconnected fractures without having to enter the matrix. The amount of oil produced from the matrix during this secondary recovery mechanism is governed by the balance of gravity and capillary forces: when the height of the matrix is large enough, the gravity forces can overcome the capillary resistance to allow the entrance of the water (imbibition) that then expels the oil. One of the main objectives of injecting pure CO_2 or chemically altered water is to modify the oil rock interactions and the oil properties to increase recovery. The physical mechanisms involved during this process have been identified but their relative importance is still an issue at both core and field scale.

To understand the small scale displacement processes followed by CO_2 and CWI at core level, a set of experiments were analysed. The cores were not fractured in order to focus on the interactions and the property changes rather than on the timing associated with them. The experiments were used to simulate the process of CO_2 and CWI after waterflooding and to evaluate the accuracy of compositional simulators in predicting oil production mechanisms.

Based on many laboratory studies (Orr et al. 1981; Lee et al. 1988; Green and Willhite 1998), CO_2 injection has been proved to be a very effective EOR process for light and medium gravity reservoir oils. The development of miscibility is one of the primary factors explaining this. At the considered reservoir pressures, the minimum miscibility pressure is exceeded and the carbon dioxide and the reservoir oil develop miscibility allowing a mass transfer between the two phases. Light and intermediate hydrocarbons are vaporised into the CO_2, which dissolves some of the CO_2 in the process. However, most of the components are recoverable within the gas. The viscosity of the remaining oil decreases and the oil swells (leading to an increase of oil saturation and its relative permeability). Viscosity reduction and swelling both contribute by improving the mobility ratio between the oil and the water: the former directly acts on the viscosity of the oil and the latter increases the oil relative permeability.

Three further phenomena improve oil production during CO_2/CWI: wettability alteration, reduction of the interfacial tension (IFT) between the oil and the water and a reduction of gravity segregation. Basic reservoir properties such as relative permeability or capillary pressure depend strongly on wettability (Kumar and Verma 2010) and reversing the wetting condition of the carbonates from oil-wet to water-wet allows the water to imbibe into the rock and expel oil more easily. This increased imbibition leads to a later water breakthrough and higher recovery factor under the same number of pore volumes injected (Dong et al. 2011). The miscibility between oil and CO_2 dramatically decreases the IFT and the viscous forces can overcome the capillary forces improving the ultimate oil recovery. Finally, gravity segregation effects are limited because of the reduction in the density contrast between the oil and the water. The reservoir oil becomes richer in heavy components after the mass transfer and has a higher density (the increase in density of the CO_2 saturated water is negligible).

Carbonated water injection is considered as an alternative to pure CO_2 injection since, in theory, it induces the same physical phenomena as the pure CO_2 but with a lower amount of carbon dioxide being injected. The water and the CO_2 are mixed prior to injection to fully saturate the water at reservoir conditions. As the solubility of CO_2 in oil is higher than the solubility of CO_2 in water (Holm 1963), diffusion mechanism allows the gas to go from the water into the oil. Moreover, compared to conventional CO_2 flooding where a sudden breakthrough of the injected gas is commonly faced, the CWI is more evenly distributed within the reservoir and has shown a very gradual CO_2 breakthrough (Kechut et al. 2010). Taking into account the final objective of implementing one of these two methods for pilot and full-field projects, CWI has a double advantage from the operational point of view: less CO_2 is required and the numbers of modifications in the injection facilities are lower (the injected fluid being acidic, corrosion resistant tubing needs to be used though). These aspects can be critical since most of the chalk fields are located offshore where the availability of CO_2 is an issue and the room for building new facilities is extremely limited. Being able to understand the relative importance of the physical mechanisms at the core scale will help to understand why the ultimate recoveries achieved with conventional CO_2 injection and CWI are not the same.

Simulating the physics involved in the recovery process and their interaction with accuracy is still a challenge. The compositional simulators currently available assume all the oil is contacted by the CO_2 and, that thermodynamic equilibrium is reached instantaneously (Kechut et al. 2011). Neither the diffusion of the CO_2 from the carbonated water into the oil nor the wettability alteration due to the surfactant effect is considered. Thus, the timing of the production process is unreliable and the final oil recovery achieved can be as high as a hundred percent if complete miscibility is achieved.

This paper presents an alternative methodology to model CO_2 and CWI at the core scale in numerical simulators. It concentrates on describing the CO_2 displacement mechanisms, their relative importance and the shortcomings of a commercial compositional simulator. Two sets of experiments, one with pure CO_2 injection and the other with CWI, are used to build a common simulation model whose robustness is tested with waterflooding matching preceding the tertiary recovery process. Then, the different physical effects and their impact on the tertiary recovery are discussed, and two methods are proposed to cope with the complete mixing assumption used by the simulator and to integrate the wettability alteration.

Literature review

Modelling CO_2 injection and carbonate waterfloods in carbonate reservoirs has been an issue since field trials and lab scale experiments showed the large potential to increase oil recovery from mature reservoirs (Christensen 1961). Starting from gas oil miscibility problems and ending with the integration of the wettability condition of the reservoir rock, there have been a series of significant contributions aiming to correctly model the various physical phenomena involved.

Todd (1979) first presented the limitations of black oil and compositional simulators to handle CO_2-oil miscibility. He proposed to ignore some phenomena which are impractical to represent such as multiple contact miscibility and the details of viscous fingering, and to focus on the effects of phase behaviour and phase transport following CO_2 injection. The model could be made to have residual oil saturation for CO_2 flooding, the process could be depicted as either miscible or immiscible as a function of pressure and water blocking of oil from the CO_2 could be represented. However, the mixing rules (how much CO_2 is dissolved in oil) had to be defined by the user and these values were assumed to be static. The use of multi-component equation of state based simulators by Leach and Yellig (1981) provided the number of phases, phase molar and mass densities, phase saturations, and the compositions of each phase. Subsequently, phase viscosities could be determined by use of correlations. This method is currently used and it allows one to correctly predict the phase behaviour once thermodynamic equilibrium has been reached; however, the transport phenomena leading to equilibrium and its timing are still outstanding issues (Kechut et al. 2010). Thus, current simulators still predict complete miscibility between oil and gas, and instantaneous equilibrium which systematically overestimate the ultimate oil recovery.

Camy and Emanuel (1977) and Potempa (1986) analysed numerical dispersion issues when simulating CO_2 injection. The size of the cells is the most critical parameter in compositional simulations and they proposed the use of pseudo relative permeability curves to reduce grid size sensitivity. Many different dispersion control methods have been proposed but recent publications still present numerical dispersion as a critical parameter that has to be controlled with sufficient grid refinement.

Grogan and Pinczewki (1987) first quantified the effect of molecular diffusion on tertiary CO_2 flooding. At the core scale, diffusion was proved to play an important role in tertiary processes since the water saturation is much higher and the mobility ratio between water and CO_2 being highly unfavourable, injected CO_2 bypasses considerable volumes of water, leaving residual oil behind. Molecular diffusion of CO_2 through the aqueous phase is considered as the main mechanism to achieve miscibility between the oil and the gas at micro or pore scale. The phenomenon is also present in CWI where the amount of injected CO_2 is low and the trapped oil cannot be contacted immediately. At a larger scale, diffusion is not considered to be a predominant parameter because of the large contact times involved. Darvish et al. (2006) reintroduced diffusion as a critical mechanism when they analysed fractured cores. Their experiments proved that the key mechanism to recover oil from the tight matrix block was also diffusion. Hoteit (2011) proposed a numerical solution for the cross-phase diffusion modelling identified by Darvish et al. (2006). Kechut et al. (2011) pointed out the limitations of current simulators to account for diffusion processes during CWI because of the much higher CO_2 content in the oil at any given time being predicted by the model.

Boade et al. (1989) developed a finite-element computational procedure for simulating reservoir compaction and subsidence processes at the field scale. The mechanical and chemical compaction mechanisms of chalk were addressed during CO_2 flooding using carbonate water at different saturation pressures, temperatures, brine composition, and residual oil saturation by Madland et al. (2006). Injection of pure CO_2 gas into water saturated chalk was proved to have a very minor effect on chalk stability. But, at stress levels below the yield point, the chalk exposed to carbonate water became considerably weaker than chalk flooded with pure water. Dissolution and compaction effects are not included in current simulators and they are not a topic of this paper.

Enick and Klara (1992) modified a compositional simulator to account for the effects of brine on CO_2 solubility and aqueous-phase density and viscosity. The solubility of CO_2 in water is much higher than that of hydrocarbon components and is a factor that cannot be neglected in the simulation process. The CO_2 solubility in the aqueous phase was set equal to that of CO_2 solubility in pure water. During pure CO_2 injection, the CO_2 dissolved in the brine lead to negligible changes in oil recovery since the aqueous phase became quickly saturated and the gas that went to the water was almost immediately replenished by the continuous injection. Chang et al. (1998) specifically studied the interaction between CO_2 and water during tertiary recovery by using a simple three-dimensional model. They concluded that about 10% of the CO_2 injected was dissolved in water and was unavailable for mixing with oil. And, in terms of timing, as much as 5% of post-waterflood oil production could be delayed by this effect.

Graue et al. (2001) conducted experimental and simulation studies in parallel to predict oil-recovery mechanisms in fractured chalk as a function of wettability. The cores were aged at high temperature in order to alter their wetting condition. Relative permeability and capillary pressure measurements were performed at reservoir conditions. Then, production profiles and in-situ saturation distributions were history matched with a simulation model that took into account the new wetting conditions. Fjelde and Asen (2010) experimentally studied the change in wettability induced by carbon dioxide flooding (**Fig. 1**). No simulation was carried out but they reported that the alteration of the wettability conditions for water-wet to more water-wet had the potential to improve the spontaneous imbibition of brine. Hascakir and Kovscek (2010) proposed a methodology to include wettability alteration during steam injection by linearly interpolating the relative permeability curves. This method used temperature as the changing parameter instead of CO_2 concentration so it would have to be adapted for carbonated water.

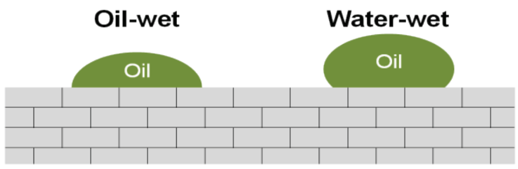

Fig. 1—Carbon dioxide flooding is believed to change the wettability of the rock (Fjelde and Asen 2010).

Shtephani (2007) first integrated interfacial tension dependent relative permeability and capillary pressure in a dynamic description. Since the miscibility between the oil and the CO_2 dramatically reduces interfacial tension, he proposed scaling factors for both relative permeability and capillary pressure. This tuning protocol would allow for more accurate evaluation and calibration of the compositional reservoir simulation model to predict actual reservoir performance.

While there have been attempts to combine all these physical mechanisms in a single simulation model, the number of sets of experiments followed by a complete simulation model is very low for both pure CO_2 injection and CWI. Beremblyum et al. (2008) first integrated in a single model all the known physical effects to model and to evaluate CO_2 injection after waterflooding. Alavian and Whitson (2010) studied the effect of several key parameters in a detailed simulation model for pure CO_2 injection. Concerning CWI, although core scale research has been quite active, very limited work on simulation models have been reported. Only Kechut et al. (2011) have recently presented an integrated experimental and simulation study of tertiary CWI where the shortcomings of current simulators and their incapability to correctly predict the ultimate oil recovery are emphasised.

This paper will study the most crucial physical phenomena involved in both pure CO_2 injection and CWI. It will emphasize the limitations of commercial simulators and propose an alternative approach to model the recovery effects. This will be achieved by working in parallel with pure CO_2 injection and CWI.

Methodology, Analysis and Discussion

The methodology proposed in order to study and to evaluate the potential of CO_2/CWI in a chalk field core can be divided into three steps. First of all, two sets of experiments are selected to be representative and comparable between each other (same formation, same fluid and similar reservoir conditions). Then, we build and validate the simulation model by history matching the coreflood experiments performed by formation water which is termed secondary recovery. Finally, we identify and assess the importance of the various physical phenomena involved in the tertiary recovery process at core scale using a compositional simulator. The shortcomings and improvements for current simulators are also discussed.

Experimental data

Core and fluid samples

The core material used in this study is from the Tor formation of Syd Arne field in the North Sea. The reservoir temperature and pressure are 115°C and 414 bar, respectively. Twenty-five 1.5" cores within the permeability range of 2.5-10 mD and porosity about 40% have been used. The CO_2 flooding experiments were carried out by ResLab Reservoir Laboratories and the carbonated water experiments were performed by GEUS.

The Reslab composite core had a cylindrical shape and it consisted of seven 1.5" plug samples juxtaposed next to each other. The composite core has to be as long as possible to ensure miscibility within the core. The ordering was determined as the order of increasing oil permeability towards the outlet end to reduce capillary end effects. The GEUS composite core had a cylindrical shape and it consisted of five 1.5" plug samples placed on top of each other in an increasing permeability sequence. The average dimension and properties of the two cores are given in **Table 1**.

Table 1—Basic data for the coreplugs selected.

Core ID	Length (cm)	Diameter (cm)	Porosity (fraction)	Pore volume (cm^3)	Absolute *k* (mD)	Wettability
Reslab	41.64	3.77	0.438	184.5	4.83	Water-wet
GEUS	28.72	3.76	0.401	127.9	4.76	Water-wet

Reslab provided several relative permeability curves for the Tor formation and they were used for modelling the experiment. Relative permeabilities are not measured for the GEUS core so we rescaled the Reslab results by using the experimental end points from GEUS. This solution was adopted since the cores came from a single set of cores. Capillary pressure measurements were not reported and, after analysing its impact on oil-recovery, it was not included in the modelling.

For the two experiments studied here, a single live oil and two brine samples were used. The reservoir oil used is from the Syd Arne field (recombined) and it has a bubble point pressure of 305.8 bar at reservoir temperature. The oil has a density of 630 kg/m^3 and a viscosity of 0.516 cP at reservoir conditions; it mainly contains light components (**Table 2**). Pure CO_2 was injected in the Reslab experiments and CO_2-saturated brine was injected in the GEUS experiments. The CO_2-enriched brine was prepared by adding 25.7 Sm^3 of CO_2 per Sm^3 of brine which corresponds to the solubility limit of CO_2 in the brine. CO_2 is soluble in oil and can extract hydrocarbons, C_5-C_{30}, from the oil. Even though CO_2 and oil are immiscible at test temperature and pressure, miscibility can be attained between the oil enriched CO_2 phase and the CO_2 enriched oil phase. **Table 3** summarises the main characteristics of oil and CO_2.

Two different brines were used in the waterflooding step for the Reslab and GEUS experiments. They both have a composition similar to the Syd Arne formation brine which is highly saline (total dissolved solid content equal to 103.7 g/L). The Reslab brine has a total dissolved solid content (TDS) of 117.5 g/L and the GEUS brine has a TDS content of 98.4 g/L. The viscosity of the GEUS brine is much higher than the one used by Reslab: 0.486 cP compared to 0.328 cP at reservoir conditions.

Table 2—Synthetic oil composition.

Component	Composition (mole percent)
N_2	0.24
CO_2	0.94
C_1	51.91
C_2	7.10
C_3	5.54
C_4	4.02
C_5	2.74
C_6	1.97
C_7-C_9	7.82
C_{10}-C_{14}	7.45
C_{15}-C_{20}	3.96
C_{21}-C_{30}	2.80
C_{30}-C_{36}	1.14
C_{37}-C_{80}	2.34

Table 3—Properties of the oil, brine and CO_2 at reservoir conditions (414 bar, 115°C).

Fluid sample	Density (g/cm^3)	Viscosity (cP)
Recombined oil (common)	0.634	0.516
Reslab brine	1.063	0.328
GEUS brine	1.066	0.486
CO_2	0.72	0.06

Experimental procedure

The composite cores were placed inside core holders which were placed inside a heating cabinet at 115°C and connected to the pumps for flooding and confining. The cores were mounted in a vertical position and flooded from the bottom towards the top. During the experiments, the differential pressure, the pore fluid pressure, the hydrostatic confining pressure, the flow rate and the cumulative fluid volume were logged.

The laboratory oil was displaced by live oil and the core left for ageing at reservoir conditions for 3 weeks. The purpose of ageing is to obtain the reservoir wetting state.

The Reslab core was flooded with the synthetic formation water described above until S_{orw} at a rate of 4.38 cm^3/hour. The injection continued until no measureable amount of oil was produced. The recovery was monitored at reservoir conditions in a separator and also evaluated by water saturation distribution measurements, measured with gamma in-situ. Then, the CO_2 flood was performed at a rate of 1.38 cm^3/hour until S_{orwg}.

The GEUS core was flooded with the synthetic formation water without CO_2 at a rate of 4 cm^3/hour. The flooding was terminated after the production plateau was reached. Then, the fluids were equilibrated in the separator by flooding CO_2-enriched water. Finally, the core was flooded with at least 7 pore volumes of synthetic formation water with CO_2 at a rate of 2 cm^3/hour.

Description of the models

One simulation model was made according to Reslab data, it included core geometry description and core properties and was simulated for water injection followed by CO_2 injection. The second model was made according to the GEUS data and was simulated for water injection followed by CO_2-enriched water injection.

The composite cores are modelled with cylindrical geometry (**Fig. 2**): radial and two dimensional with a total of 18×1×100 grid blocks representing the ⌀3.77×41.64 cm Reslab chalk core (⌀3.76×28.72 cm for GEUS core). A fine grid is used to reduce numerical dispersion (Alavian and Whitson 2010; Kechut et al. 2011) and only a 90° sector of the core is studied to speed up the simulations. No fracture system is included. The composite cores from the experiments presented a series of heterogeneities in the physical parameters such as the porosity and the permeability that has not been taken into account in the final numerical model. However, a sensitivity analysis was run by adding this kind of heterogeneities in different regions of the core and it was decided not to include them because of the small impact on the final results. Thus, the model assumes homogeneous porosity and permeability, and the experimental values are used. Initial reservoir conditions are 414 bar and 115°C.

In both models (Reslab and GEUS) the injector is located at the bottom, while the producer is located at the top. All the injectors reproduce the experimental boundary conditions and the producers do not have any constraint on the rates. Two injection wells are used for CO_2-enriched water (GEUS case), one is injecting water and the other one is injecting CO_2. The wells used for CO_2-enriched water inject at the same time different quantities of water and CO_2 in the lowermost cell, according with requested concentrations of CO_2 in water.

ECLIPSE 300 compositional simulator has been used and the PVT data is taken from the Syd Arne field fluid results. The use of a compositional simulator instead of a black oil simulator allowed the mass transfer phenomena to be studied. A 14-component Soave-Redlich-Kwong equation (Soave 1972) with temperature dependent Peneloux volume correction (Peneloux et al. 1982; Pedersen et al. 2004) is used as the equation of state. The EOS model was checked against the gravity value, the viscosity value and the CO_2 swelling test results. Also, as part of the sensitivity study, the correlation developed by Bando et al. (2004) was used to estimate the viscosity of the carbonated water at the test conditions.

Fig. 2—Illustration of the core model grid. Both water and CO_2 are injected from below.

Corefloods: matching the experimental data

In this section the experimental data is matched for both secondary and tertiary production processes. The shortcomings of the simulator in terms of CO_2 handling are presented and an alternative methodology is proposed to achieve an acceptable match.

Waterflooding results

Before the waterflooding started, the core was saturated with the Syd Arne field fluid and 5.1% of water at 414 bar and 115°C. The endpoints of the relative permeability curves come from Reslab experiments but the shapes of the water/oil relative permeabilities have been varied by using different Corey exponents to get a satisfactory match. **Fig. 3a** presents the set of curves used in the final simulation.

Fig. 3b and 3c present the cumulative oil production profile and the differential pressure across the core during waterflooding. The water breakthrough is noticed in the Reslab experiment after 0.63 PV of water has been injected and 0.62 PV of oil produced while in the simulation breakthrough starts after 0.62 PV of water has been injected and 0.61 PV of oil produced. The vertical sweep efficiency of the production process is very high since only 0.06 PV of oil is produced after breakthrough to achieve 67% PV of oil produced after 2.4 PV of water injected. The presence of heterogeneities in the real core explains the jumps in the differential pressure noticed prior to breakthrough in the measured data (**Fig. 3c**). These are not reproduced by the simulation results and, associated with the lack of information about permeabilities of the composite cores, they explain the poor match of the differential pressure prior to breakthrough. Apart from that, results are very similar and the history match of waterflooding is considered satisfactory.

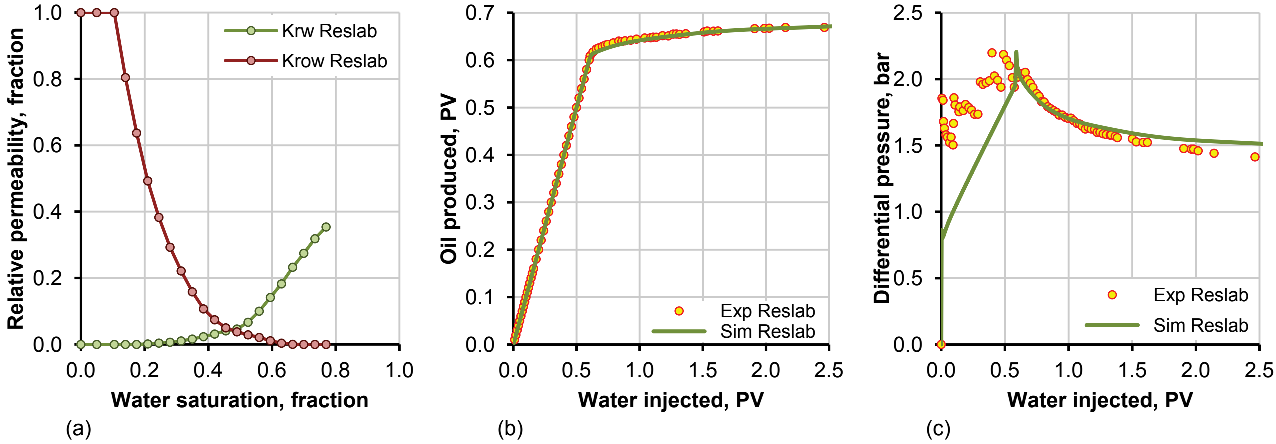

Fig. 3—(a) Relative permeability functions used for matching the experimental data. Comparison between experimental and simulated (b) cumulative oil produced and (c) differential pressure across the Reslab core. The resulting good match validates the model.

The initial conditions for the GEUS waterflooding were the same as Reslab's except for the initial water saturation which was equal to 4.8% PV. The experimental end points from GEUS were used to rescale the relative permeability curves from Reslab. The experimental results (**Fig. 4b**) show extremely effective sweep efficiency as no further oil is recovered after water breakthrough. The simulation results are not as good as before but the main objective was to match the final recovery (65% PV of oil) and the differential pressure after breakthrough by modifying the relative permeability curves as little as possible.

The consistency of both models has been proved by properly matching the waterflooding processes and the next step will focus on CO_2 and CWI.

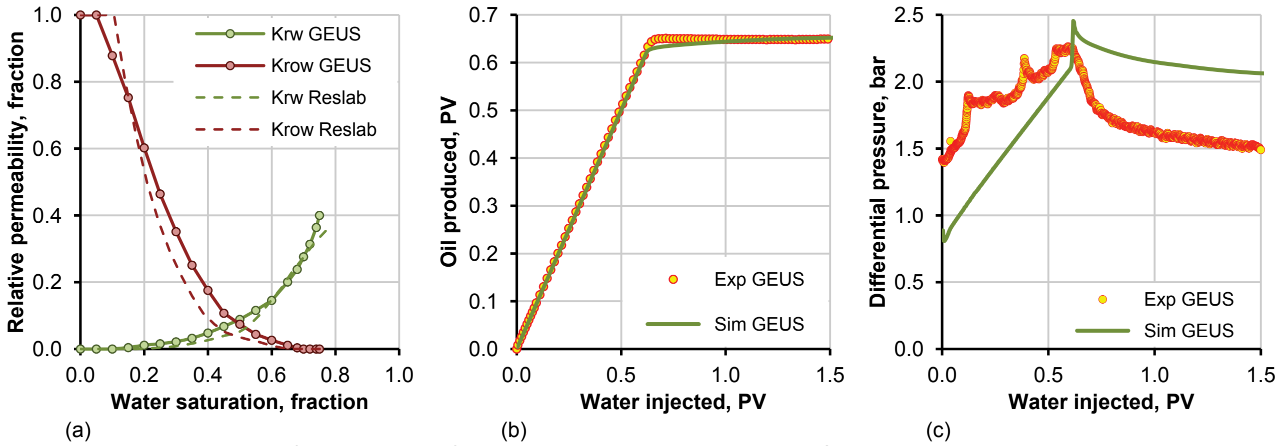

Fig. 4—(a) Relative permeability functions used for matching the experimental data. Comparison between experimental and simulated (b) cumulative oil produced and (c) differential pressure across the GEUS core. The differential pressure could not be properly matched with the same relative permeability functions and the mismatch is beyond the error in the pressure measurements.

CO_2 injection results

After 2.4 PV of water had been injected and no measureable amount of oil was produced, the CO_2 flood of Reslab core started at a rate of 1.38 cm^3/hour. The previous waterflood had recovered 67% PV of oil leaving 27.9% PV of residual oil. The experimental results (**Fig. 5**) show an important increase in recovery with CO_2 injection since an additional 15% PV of the waterflood trapped oil was produced. Residual oil after CO_2 flooding S_{orwg} was 12.9% PV of oil.

The initial simulation results with ECLIPSE 300 default settings predicted oil recovery during CO_2 injection to be much higher (as high as a 100% of oil recovered) than the experimental value. Indeed, ECLIPSE 300 assumes instantaneous equilibrium and complete convective mixing between CO_2 and oil. This leads to very high recoveries due to a reduction in oil viscosity and an extreme swelling effect. The poor treatment of both phenomena by the simulator was expected and one of the objectives is to propose alternative approaches to match the experimental data.

Two methods are used to impose residual oil saturation in compositional simulation of the miscible gas injection process: the alpha-factors (Barker et al. 2005) and the bypassed oil (Coats et al. 2007). Alpha-factors are transport coefficients that modify the composition of the oil or gas flowing by speeding up some components and slowing down the others. They are a purely numerical concept, somewhat analogous to pseudo relative permeability but for components instead of phases. The main inputs required to generate the alpha-factors are the composition of the oil after waterflooding, the oil and CO_2 molar densities and the desired oil saturation. The alpha-factors were computed using Barker et al. (2005) method. The second method (bypassed oil) considers the residual oil as part of the rock. Indeed, the same effect is obtained by reducing the porosity of the rock but it requires re-scaling the relative permeability curves and changing the rock compressibility. The latter is a second order effect that can be neglected (Coats et al. 2007). The equivalent porosity ϕ' includes the amount of bypassed oil,

$$Producible\ oil = V_b \times \phi \times (1 - S_{wi} - S_{orm}) = V_b \times \phi' \times (1 - S_{wi}) \quad \text{.......(1)}$$

and so,

$$\phi' = \phi \times \frac{1-S_{wi}-S_{orm}}{1-S_{wi}}. \quad \text{.......(2)}$$

The relative permeability curves are adjusted with the new residual oil saturation defined by

$$\phi' \times S'_{orw} = \phi \times (S_{orw} - S_{orm}). \quad \text{.......(3)}$$

Substituting Eq. 2 for ϕ' yields

$$S'_{orw} = \frac{(S_{orw}-S_{orm})/(1-S_{wi})}{(1-S_{wi}-S_{orm})}. \quad \text{.......(4)}$$

Both methods are implemented after the waterflooding phase to match the experimental data and the results are presented in Fig. 5. The alpha factor method represents better the CO_2 breakthrough (**Fig. 5b**) which happens after 0.3 PV of CO_2 have been injected. This is certainly due to a change in the dynamics of the recovery since the heavier components are not swelled by the gas. This is equivalent to a reduction of the miscibility of the gas into the oil and has an impact on the timing. However, the final recovery predicted by this method is still above the one observed. The bypassed oil method matches correctly the final recovery but the timing is not modified: both instantaneous equilibrium and complete miscibility happen.

The alpha-factors are calculated assuming fixed water saturation so the method is not appropriate in the cases where water is injected after or during gas injection. And, this is the case of CWI. Moreover, keeping in mind the objective of studying the effect of CO_2 injection at the field level where solution gas might be present because of the reduction in the reservoir pressure, the method is not appropriate. Thus, the bypassed oil method is the preferred method to investigate the effects of the other phenomena.

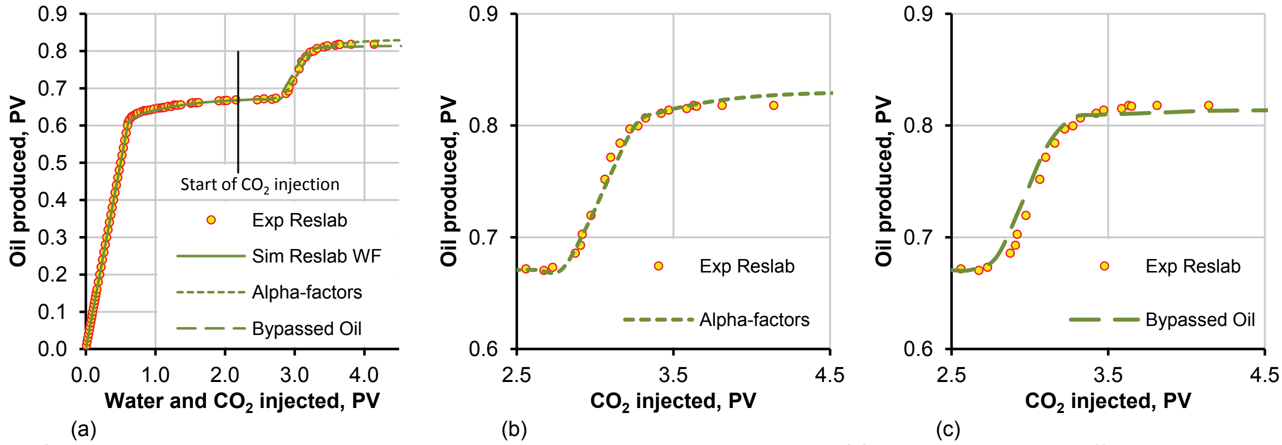

Fig. 5—Comparison between experimental and simulated (a) oil produced during pure CO_2 injection with two different methods. Detail of the tertiary recovery phase for (b) the alpha-factors method and for (c) the bypassed oil method. The bypassed oil method matches correctly the final recovery achieved.

One of the critical effects common to pure CO_2 injection and CWI is the solubility of the CO_2 into the water. The microscopic effects are different depending on the solubility value since the CO_2 is allowed to travel through the water and to reach the trapped oil to swell it. Also, the water composition is modified and this leads to a change in the wettability of the rock which is mainly in contact with water. However, this effect is not taken into account by the simulator. The immiscible case is studied by setting the solubility of the CO_2 into the water to zero and **Fig. 6** presents the results. Since water cannot be used anymore as a transport medium, the CO_2 is forced to displace the water and a delay in the CO_2 breakthrough is noticed (**Fig. 6b**). Also the swelling effect is much more important causing a transient and artificial reduction in the oil produced as it can be inferred from Fig. 6b. The final recovery is not affected by this change since the miscibility between the oil and the CO_2 is still complete.

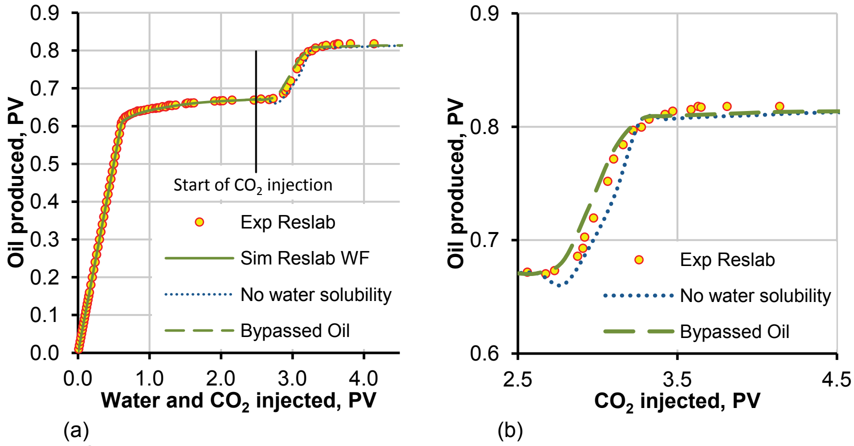

Fig. 6—Comparison between experimental and simulated (a) oil produced during pure CO_2 injection with and without water solubility into the oil. Detail of the tertiary recovery phase for (b) the alpha factors method with and without water solubility.

Two other physical phenomena are studied: the oil viscosity change due to development of miscibility and oil swelling, and the wettability effect. ECLIPSE 300 does not have the capability to change the oil viscosity directly and the idea is to use modified permeabilities to capture this effect. Indeed, in all equations where oil viscosity appears, it is always associated with permeability (oil mobility). Thus, an increase in oil viscosity can be achieved by a decrease in oil permeability. The change in wettability of the rock can also be modelled by a modification of the relative permeabilities (Anderson 1987). Thus it was decided to focus on the wettability change since the capability is not included in the simulator at all and the methodology can be used for both phenomena. The objective is to modify the relative permeability curves during the CO_2 flooding phase: a function that degrades the relative permeability curves as the concentration of a chosen compound increases is used. This is convenient for the water relative permeability curve since a more water-wet state leads to a lower (more degraded) water relative permeability curve. However, the oil relative permeability curve gets higher as the wetting condition goes from oil to water-wet so the idea was to start with a "degraded oil relative permeability curve" (corresponding to the initial condition) and to use a compound whose concentration decreases through the experiment. Thus, the behaviour would be the opposite and the oil relative permeability would improve as the experiment goes on. The modified relative permeability values are computed as

$$k_{ri} = M_w \times k'_{ri} \quad \text{(5)}$$

where k'_{ri} is the relative permeability prior to the wettability calculation and M_w is the wettability multiplier given by

$$M_w = \frac{1}{1+W(k'_{ri})\times \max(0, Z-I)} \quad \text{(6)}$$

where W is the wettability factor for a chosen component, Z is the molar concentration of the component and I is the initial concentration of the component.

The wettability multipliers are a dynamic tool that allows the whole range of values between the initial relative permeability curve and the maximum relative permeability curve to be explored (**Fig. 7a**). The range of variation for the permeability was defined with the literature (Anderson 1987) since no experimental data is available. Wider changes in relative permeability were explored (up to cross-shaped curves) but they all lead to similar results. As the CO_2 front propagates through the core, the rock becomes more water wet and this has an impact on the oil/water flow properties.

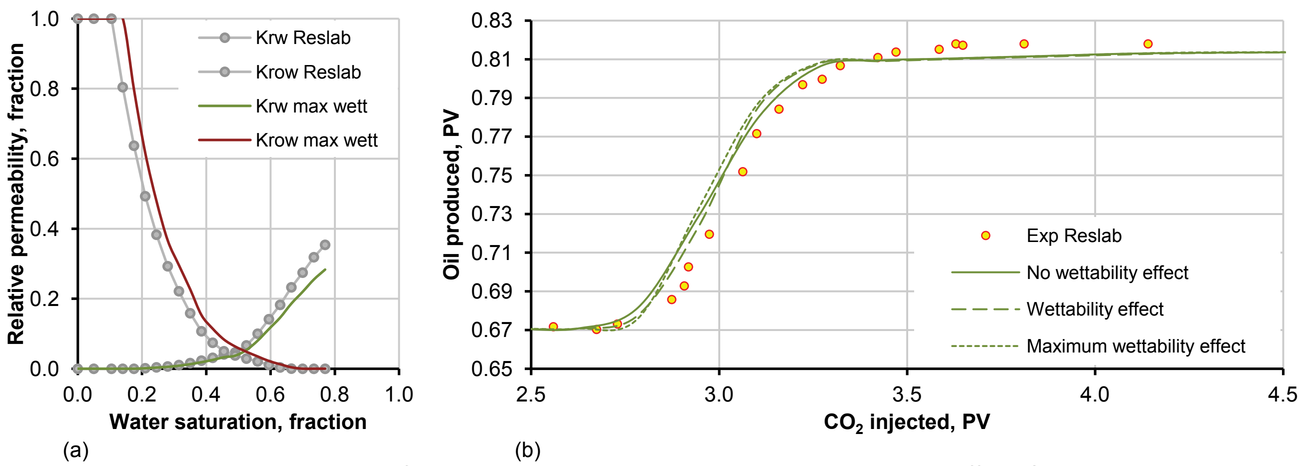

Fig. 7—(a) Relative permeability curves defining the boundaries used to include the wettability effect. Comparison between experimental and simulated (b) cumulative oil produced with no wettability, extreme wettability and progressive wettabilitty. The difference in the production profile due to the wettability change is negligible.

The maximum wettability effect in **Fig. 7b** corresponds to the case where the wettability of the rock-and therefore the relative permeability curves-instantaneously reaches its extreme value as soon as the CO_2 injection starts. This case has no physical significance but it sets the maximum change permitted for the recovery curve. The wettability effect curve is obtained by using the wettability multipliers which modify the relative permeability of the rock as CO_2 propagates. CO_2 breakthrough happens slightly later compared to the case where wettability is not taken into account. This is due to a decrease in the ability of the water to flow and water is one of the preferred media for CO_2 to travel within. Apart from this, wettability changes have a negligible impact on the overall recovery profile (the ultimate recovery is not studied here).

CWI results

After 1.5 PV of water had been injected and no oil was produced, the carbonated water flood of the GEUS core started. The carbonated water, which contained 25.7 Scm^3 per Scm^3 of water, was injected at a water rate of 2 cm^3/hour. The previous waterflood had recovered 65% PV of oil leaving 30.2% PV of residual oil. The experimental results (**Fig. 8**) show a non negligible increase in recovery with CWI since an additional 7.5% PV of the waterflood trapped oil was produced. The residual oil after carbonated water flooding S_{orwg} was 22.7% PV of oil but this value was only achieved after more than 14 PV of carbonated water had been injected. A non-expected production phase has been identified during the first one and a half pore volumes of CO_2-enriched water injected (**Fig. 8b**): 1% PV of oil was produced at a rate that decreased to zero. Before CWI started, the fluids in the separator were equilibrated with CO_2-enriched water and it is concluded that a small amount of mobile oil accumulated in the upper part of the core during this step previous to the proper experiment.

Prior to injection, CO_2 is dissolved in the water so no gas phase is present in the core at any moment. Consequently, the bypassed oil method is not appropriate and will not be used since all blocks remain undersaturated. However, as **Fig. 8a and 8b** show, the simulation results with CO_2 allowed to dissolve in the oil, leads to high recoveries very rapidly (an additional 12% PV of oil after 6 PV of carbonated water injected). Both ultimate recovery and timing of the process are badly predicted because too much CO_2 is transferred from the water into the oil making it swell. To limit this phenomenon, it was decided to modify the CO_2 aqueous phase properties which follow the correlations given by Chang et al. (1998) and to increase the CO_2 solubility in the water. Thus, CO_2 is forced to stay in the water and cannot contact all the residual oil in place. This case is extreme but it allows isolation of the different phenomena involved. The results are presented in Fig. 8 and show that development of miscibility between oil and supercritical fluids is the most important effect governing the recovery process. Moreover, the improvement achieved in the match of the differential pressure across the core (**Fig. 8c**) confirms that the complete miscibility assumption is not acceptable.

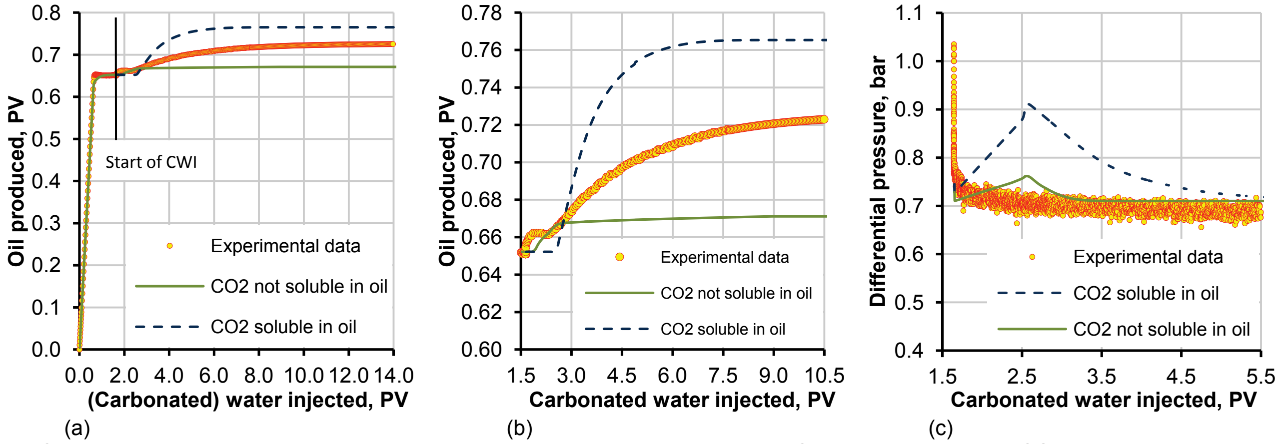

Fig. 8—Comparison between experimental and simulated (a) oil produced during CWI with and without CO_2 solubility into the oil. Detail of the (b) tertiary recovery phase with and without CO_2 solubility. (c) Differential pressure across GEUS core during CWI. ECLIPSE 300 default assumptions lead to very high recovery in a short lapse of time.

Even though the pressure match is improved by reducing the solubility of CO_2 into the oil, there is still an important gap between the experimental data and the simulation results (Fig. 8a and 8b). Wettability effects are not taken into account by the simulator and in the previous section a methodology was presented to include them. Based on the literature (Anderson 1987), two new sets of permeability curves corresponding to the most water wet conditions of the rock are defined (**Fig. 9a**). The approach (progressive wettability) ensures that the relative permeabilities of the fluids change as the CO_2-enriched water front propagates through the core. The maximum wettability case in **Fig. 9b and 9c** corresponds to the case where the wettability of the rock-and therefore the relative permeability curves-instantaneously reaches its extreme value as soon as the CWI starts. The results for the three cases (no wettability, maximum wettability and progressive wettability) are presented in Fig. 9b and 9c. The change in the shape of the relative permeability curves does not fill the gap observed between the experiments and the simulation. The wettability change has a non-negligible effect on the recovery profile but at the same time the differential pressure across the core is increased by almost a factor two. The shape of the differential pressure curves that include the wettability change are consistent (the more water wet the rock is, the more difficult the water flows thus increasing the pressure) and the values converge towards a common value. However, the increase in the differential pressure and the associated mismatch with the experimental data raises the question about the importance and the modelling approach for this phenomenon.

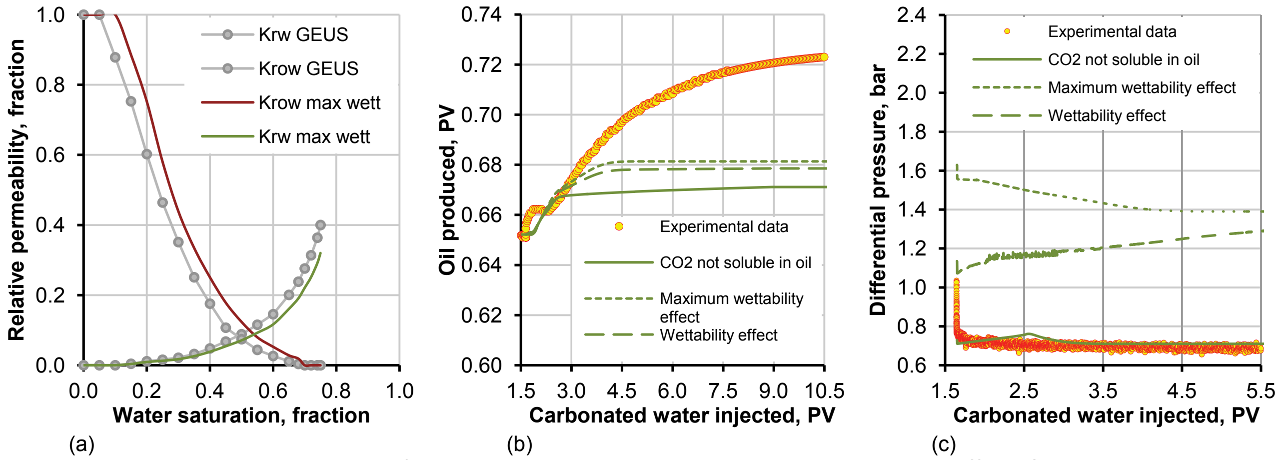

Fig. 9—(a) Relative permeability curves defining the boundaries used to include the wettability effect. Comparison between experimental and simulated (b) cumulative oil produced with no wettability, extreme wettability and progressive wettabilitty. The difference in the profile due to the wettability change do not explain the gap in production and the pressure constraint is no longer honoured.

Discussion

The coreflood experiments with both pure CO_2 and carbonated water increase oil recovery from waterflooded cores to achieve an incremental recovery of 15% PV and 7.5% PV of oil respectively. These reductions in the residual oil are consistent with the ones reported by Berenblyum et al. (2008) and Kechut et al. (2010). All production profile curves for secondary and tertiary recovery except for pure CO_2 injection were accompanied with experimental differential pressure curves across the core. This supplementary constraint ensured the model to be robust and consistent. The simulation runs helped to investigate the effects of CO_2 and CWI on oil production and the ability of current simulators to capture the associated physical phenomena.

Among the phenomena properly captured is the effect of dissolved CO_2 in water on water viscosity. Nearly constant values of viscosity leading to minor changes in the final recovery were found which is consistent with the results reported by Sayegh and Najman (1987). Despite the higher viscosity of carbonated water compared to plain water, the differential pressure across the core during CWI was less than that of plain water injection. This indicates a higher operational efficiency and higher injectivity of CWI compared to water injection.

The recovery at any stage of the process is over-predicted and, in particular, the final recovery during gas injection reaches values as high as a 100% PV of oil produced. The same results are reported by Coats et al. (2007) and Kechut et al. (2010 and 2011) for both conventional CO_2 injection and CWI. The simulator calculations suppose instantaneous equilibrium between the three fluids present in the core, regardless of the size of the grid block, and complete miscibility between oil and gas is improperly assumed. Swelling effect and the viscosity change of the oil becomes unrealistic with the oil viscosity decreasing from 0.52 cP to 0.06 cP. The complete miscibility assumption is particularly incorrect since the viscosity ratio between the oil and the injected CO_2 or carbonated water is relatively high and an unstable front displacement leading to fingering effects is expected in the core experiments. The inability of the simulator to capture the dominant production mechanism in the early stages of the experiment can be explained because the mass transfer modelling (vaporisation, condensation and molecular diffusion) is simply absent.

A new simulation approach is proposed to limit the negative effects of these simplistic assumptions. The bypassed oil method is more appropriate than the alpha-factors method since it is not affected by important variations in the pressure of the core/reservoir. Also, the presence of heterogeneities in the CO_2 distribution at a larger scale and/or the alternate injection of gas and water would not be an issue for this method. There is a good match between the simulation runs and the pure CO_2 injection experiment. However, the simulator cannot be seen as a predictive tool anymore since the model was initially set to achieve the final recovery observed in the experiments. The approach allows limitation of the effect of miscibility but does not quantify it compared to other physical mechanisms governing the recovery process.

Wettability is believed to be an important factor influencing multiphase flow in reservoir rock. Spontaneous imbibition experiments have shown that carbonated water injection reverses the wetting condition of the carbonates from oil-wet to water-wet (Graue et al. 2001). This allows the water to imbibe into the rock and expel oil more easily. Wettability alteration has a triple effect on the fluid distribution and the flow properties: relative permeabilities, capillary pressure and residual oil saturation are all modified. The method proposed to model wettability changes in a compositional simulator is an approximation since it deals with relative permeability changes but does not alter the capillary pressure nor the residual oil saturation. The latter is directly associated with the relative permeability end-points which are not allowed to be modified.

Moreover, the wettability change is governed by the surface chemistry and the adsorption properties of the rock. Thus, the changes in the wetting condition might not occur immediately. No experimental data being available to quantify the timing of the reaction, the proposed method applies the change as soon as the CO_2 contacts the rock. Considering all these limitations, the results show that the recovery mechanism is influenced by rock wettability change during both pure CO_2 injection and CWI but this influence is not as important as the development of solubility.

The solubility of CO_2 in oil is higher than that of water and as a result when carbonated water comes in contact with oil in the core, it loses some of its CO_2 content to the oil. This will improve the physical properties of the oil and swell it. Carbonated water and formation water have very similar mobilities, a consequence of which is that a larger part of the core is supposed to be swept by carbonated water compared to conventional CO_2 injection. The simulation results show that the miscibility effect governs the recovery process during CWI. The main difficulty remains in developing a method to quantify and to model this effect. CWI transports CO_2 more efficiently and evenly to the oil; but current simulators simply assume that when CO_2 and oil are in the same cell they develop miscibility. The use of molecular diffusion as an alternative to model this effect is not possible, as the current simulator does not allow for the molecular diffusion of components between different fluids but only between different phases of the same fluid. Furthermore, a detailed experimental study of the diffusivity coefficients should be performed prior to implementation.

Nevertheless, the relative importance of these phenomena might not be the same at core and at field scale. Most of the chalk reservoirs in the North Sea are either naturally fractured or have been fractured as a consequence of the extensive waterflooding carried out during secondary recovery. CO_2 injection has been considered for its potential to enhance oil recovery from fractured reservoirs (Alavian and Whitson 2010). Few detailed simulation models have been built and the complex interaction between matrix and fracture system is not well known. All the phenomena presented at the core scale are present at the field scale but their relative importance might be changed. For instance, capillary pressure has been proved to be negligible at the core level but it is known to be a fundamental mechanism in expelling the oil out of the matrix. When the height of the matrix is large enough, the gravity forces can overcome the capillary resistance to allow the entrance of the water (imbibition) that then expels the oil. In the absence of fractures, diffusion is also considered to have a little impact at the core level because of the homogeneous distribution of the injected fluids and the short time scale of the coreflood experiments. However, when the system is fractured and the time scale of diffusion is of the same order of magnitude as the other mass transfer mechanisms (Grogan and Pinczewski 1986; Todd et al. 1982), then diffusion becomes important. This fact, the higher operational efficiency and injectivity of CWI compared to water injection, and the gradual breakthrough of CO_2 compared to pure CO_2 injection seem to make CWI an interesting alternative to conventional CO_2 injection in a field setting. Nevertheless, it is delicate to predict or to suggest based on the core model what the field scale modelling should be.

Conclusions

Based on the experiments and the subsequent numerical simulations of pure CO_2 and CWI, it can be concluded:

1. CO_2 and CWI both increase the ultimate oil recovery after waterflooding. Conventional CO_2 achieves the increase much faster than CWI.
2. The current compositional simulators do not properly capture the dominant production mechanism (mass transfer) and the final recovery is systematically over-predicted.
3. The bypassed oil method allows matching of the experimental data for pure CO_2 injection but it dramatically reduces the ability of the simulator to predict transient and final recoveries. The physics involved in the process cannot be properly captured at the core scale.
4. Including the change in wettability during CO_2 and CWI makes the model more realistic. However, the wettability change of the rock is not limited to the shape of the relative permeability curves whose impact on the recovery behaviour is minor.
5. Upscaling from the core level to the field level cannot be done immediately and the relative importance of the various physical phenomena involved in the recovery process has to be revisited.

Recommendations

In order to use the simulators as a predictive tool capable of comparing the performances of pure CO_2 injection and CWI at the core level, the following steps should be considered:

1. Perform a new set of experiments with CO_2 and CWI after waterflooding in a larger core (not a composite one) including a fracture. The core should be large enough to allow large scale mechanisms, pertinent at the field scale, to develop.
2. Continuously measure oil and gas production, pressure and fluid compositions. This will help to constrain the simulation model parameters and to further understand predominant mechanisms like vaporisation or condensation.
3. Build empirical correlations between the changes in wettability and their impact in relative permeabilities, capillary pressure and residual oil saturation. Study the timing of the wettability alteration reactions.
4. Confirm the critical aspects of reservoir simulators that have to be improved and propose a new physical model.

Nomenclature

I	=	initial concentration of the component, n, mol
k	=	absolute permeability, L^2, mD
k_{ri}	=	relative permeability
$k_{ri}^{'}$	=	relative permeability prior to wettability change calculation
k_{row}	=	oil relative permeability
k_{rw}	=	water relative permeability
M_w	=	wettability multiplier
S_{orm}	=	bypassed-oil saturation, fraction
S_{orw}	=	bypassed method oil residual saturation after waterflooding, fraction
$S_{orw}^{'}$	=	oil residual saturation after waterflooding, fraction
S_{orwg}	=	oil residual saturation after tertiary recovery, fraction
S_{wi}	=	initial water saturation, fraction
V_b	=	gross volume of the core, L^3, cm^3
W	=	wettability factor
Z	=	molar concentration of the component, n, mol
ϕ	=	porosity, fraction
$\phi^{'}$	=	bypassed method porosity, fractions

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Appendix A—Critical literature review

Table A1—Milestones in simulation of CO_2/CWI EOR for chalk fields.

SPE Paper n°	Year	Title	Author(s)	Contribution
6894	1977	"Effect of Grid Size in the Compositional Simulation of CO_2 Injection"	Camy, J.P. Emanuel, A.S.	First to analyse numerical dispersion issues when simulating CO_2 injection with a compositional simulator
7998	1979	"Modeling Requirements for Numerical Simulation of CO_2 Recovery Processes"	Todd, M. R.	First to present the limitations of black oil and compositional simulators to handle CO_2-oil miscibility
12706	1987	"The Role of Molecular Diffusion Processes in Tertiary CO_2 Flooding"	Grogan, A.T. Pinczewski, W.V.	First to quantify the effect of molecular diffusion on tertiary CO_2 flooding
17855	1989	"Forecasting of Ekofisk Reservoir Compaction and Subsidence by Numerical Simulation"	Boade, R.R. Chin, L.Y. Siemers, W.T.	First to develop a finite-element computational procedure for simulating reservoir compaction and subsidence processes at the field scale
20278	1992	"Effects of CO_2 Solubility in Brine on the Compositional Simulation of CO_2 Floods"	Enick, R.M. Klara, S.M.	First to account for the effects of brine on CO_2 solubility and aqueous phase density and viscosity in a compositional model.
74335	2001	"Wettability Effects on Oil-Recovery Mechanisms in Fractured Reservoirs"	Graue, A. Bognø, T. Baldwin, B.A. Spinler, E.A.	First to conduct experimental and simulation studies in parallel to predict oil-recovery mechanisms in fractured chalk as a function of wettability.
111290	2007	"Experimental and Modeling Requirements for Compositional Simulation of Miscible CO_2-EOR Processes"	Shtepani, E.	1. First to couple the fluid phase behaviour with the flow through porous media 2. First to integrate interfacial tension dependent relative permeability and capillary pressure in a dynamic description
113436	2008	"Modeling CO_2 Injection: IOR Potential after Waterflooding"	Beremblyum, R. Calderon, G. Kollboth, L. Surguchev, L.M.	First to integrate in a single model all the known physical effects to model and to evaluate CO_2 injection after waterflooding
139528	2010	"CO_2 EOR Potential in Naturally Fractured Haft Kel Field, Iran"	Alavian, S.A. Whitson, C.H.	First to propose a full field scale CO_2 injection model to estimate the CO_2 injection potential in a naturally fractured reservoir
143005	2011	"Experimental and Numerical Evaluation of Carbonated Water Injection (CWI) for Improved Oil Recovery and CO_2 storage"	Kechut, N.I. Sohrabi, M. Jamiolahmady, M.	First to demonstrate that CWI increases oil recovery of waterflooded reservoirs above that of the plain water injection

SPE 6894 (1977)

"Effect of Grid Size in the Compositional Simulation of CO_2 Injection"

Authors: Camy, J.P. and Emanuel, A.S.

Contribution to the understanding of simulation of CO_2/CWI EOR for chalk fields

First to analyse numerical dispersion issues when simulating CO_2 injection with a compositional simulator.

Objectives of the paper

Propose pseudo-functions for reducing dispersion and mixing errors in a multicomponent finite difference compositional simulator. The technique implemented is aimed at deriving pseudo functions from small fine grid models for use in large scale coarse grid models.

Methodology used

1. Run a series of linear models to determine the cell size of the fine grid model
2. Develop a series of pseudo relative permeability curves from the fine grid for each phase and each component. These curves will adapt the water saturation and the hydrocarbon component concentration profiles to a much coarser grid.
3. Assuming the curves enable the coarser grid model to move the right amount of each component, a series of pseudo K-values is derived to reproduce the phase saturations.

Conclusions reached

1. The use of pseudo relative permeability curves and pseudo K-values can effectively reduce grid size sensitivity in compositional simulation. This allows to simulate a larger area while using fewer grid points.
2. The results are limited to a range of pressure, rate, slug size and composition close to that used in deriving the pseudo function.

Comments

The recommendations from this paper and from Potempa (1986) where followed to decide on the number of layers to be used in the simulation model.

SPE 7998 (1979)

"Modeling Requirements for Numerical Simulation of CO_2 Recovery Processes"

Author: Todd, M. R.

Contribution to the understanding of simulation of CO_2/CWI EOR for chalk fields

First to present the limitations of black oil and compositional simulators to handle CO_2-oil miscibility.

Objectives of the paper

The ultimate objective of the work is to develop a numerical simulator that could be used to aid in the engineering design of a CO_2 displacement project. The simulator must be able to properly model mass transfer phenomena and other features common to a chemical flood model.

Methodology used

1. Describe the process of CO_2 injection from the physics point of view: pressure regimes, phase equilibria and phase transport.
2. Assess current model results and compare them with laboratory data. Show the limitations of currently available modelling techniques.
3. Propose the salient features that should be included in a viable CO_2 flooding model in terms of phase behaviour and phase transport.

Conclusion reached

Much of the CO_2 process is improperly treated by reservoir simulators and the complex interaction of the various phenomena involved must be further modelled a field-oriented numerical reservoir simulator.

Comments

This paper raises an issue which has not been solved yet.

SPE 12706 (1987)

"The Role of Molecular Diffusion Processes in Tertiary CO_2 Flooding"

Authors: Grogan, A.T., Pinczewski, W.V.

Contribution to the understanding of simulation of CO_2/CWI EOR for chalk fields

First to quantify the effect of molecular diffusion on tertiary CO_2 flooding. The analysis was done for tertiary recovery experiments where CO_2 is injected into a previously watered-out test core.

Objective of the paper

The purpose of the paper is to examine the role of molecular diffusion and to determine the time scales necessary for diffusion to be an effective recovery mechanism in both laboratory floods and in the field.

Methodology used

A numerical model is built based on CO_2 transport equations and the solution obtained is validated by comparison with the analytical solution of the problem. Then, the model system parameters (partition coefficients for CO_2 in oil and water, CO_2 solubility in water and diffusion coefficients) are estimated. Finally the whole model is applied to a laboratory case study.

Conclusions reached

1. Molecular diffusion plays a dominant role in the recovery of waterflood residual oil on the micro or pore scale.
2. Sufficient contact time must be allowed for diffusion of CO_2 to swell the residual oil effectively if high displacement efficiencies are to be realised.
3. It is unlikely that molecular diffusion plays a significant role in reducing the adverse effects of large-scale bypassing resulting from gravity segregation, reservoir stratification, and unfavourable mobility ratio in tertiary field floods.

Comments

The study performed by Grogan and Pinczewski shows the importance of diffusion which could not be evidenced in our study since the complete miscibility assumption and the instantaneous equilibrium where predominant in the simulation cases. In addition, no diffusion coefficients had been reported.

SPE 17855 (1989)

"Forecasting of Ekofisk Reservoir Compaction and Subsidence by Numerical Simulation"

Authors: Boade, R.R., Chin, L.Y., Siemers, W.T.

Contribution to the understanding of simulation of CO_2/CWI EOR for chalk fields

First to develop a finite-element computational procedure for simulating reservoir compaction and subsidence processes at the field scale.

Objectives of the paper

To develop a numerical model able to forecast the highly nonlinear compaction behaviour of chalk and the coupled physical processes like subsidence.

Methodology used

A basic computational methodology is presented with the model of the reservoir and the calculation methods applied to estimate the effects of subsidence. No mathematical model is presented since two commercial finite-element codes were used. The rest of the paper proves the consistency of the tool by history matching the results with Ekofisk field data: subsidence bowl profiles, subsidence rates vs. time, compaction vs. time and the arch effect (overburden effect on compaction phenomenon).

Conclusions reached

1. Calculated results for subsidence, subsidence rates, and subsidence-bowl profiles are in generally good agreement with recent measurements.
2. Injecting gas at a high rate to maintain reservoir pressure is an effective means to control reservoir compaction and subsidence.
3. The simulation runs indicate that reservoir compaction and attendant deformation of the surrounding meadia lead to changes in in-situ stress fields.

Comments

Dissolution and compaction effects are not included in current simulators and they are not a topic of our paper. They are believed to be a major issue in large scale CO_2 injection.

SPE 20278 (1992)

"Effects of CO_2 Solubility in Brine on the Compositional Simulation of CO_2 Floods"

Authors: Enick, R.M., Klara, S.M.

Contribution to the understanding of simulation of CO_2/CWI EOR for chalk fields

First to account for the effects of brine on CO_2 solubility and aqueous phase density and viscosity in a compositional model.

Objectives of the paper

The interaction between CO_2 and hydrocarbons is altered by the presence of water in the core. The goal of the study is to correlate these effects accurately and simply, to incorporate them into a reservoir simulator, and to evaluate their significance on the modelling of CO_2 floods.

Methodology used

Henry's law and an empirical correlation for the effects of dissolved solids on solubility were used to predict CO_2 solubility in the aqueous phase. Three simulation cases were compared to evaluate the importance of CO_2 presence in CO_2/hydrocarbon interactions:

1. Case 1: CO_2 is not allowed to dissolve in the aqueous phase
2. Case 2: CO_2 solubility in the aqueous phase is equal to that of CO_2 solubility in pure water
3. Case 3: the effect of dissolved solids in the aqueous phase on CO_2 solubility was considered

Conclusions reached

1. Very small changes in oil recovery occur as a result of CO_2 solubility in brine in the continuous displacement of oil by CO_2 because the aqueous phase becomes saturated with CO_2.
2. Large decreases in oil recovery can result when a slug of CO_2 is used to displace the hydrocarbons.
3. The Changes in water density and viscosity caused by dissolved solids were not significant.

Comments

The empirical correlation used to account for the effects of dissolved solids on solubility was not detailed in the paper.

SPE 35164 (1998)

"A Compositional Model for CO_2 Floods Including CO_2 Solubility in Water"

Authors: Chang, Y.B., Coats, B.K., Nolen, J.S.

Contribution to the understanding of simulation of CO_2/CWI EOR for chalk fields

First to model oil recovery processes involving CO_2 injection while taking into account the effects of CO_2 solubility in water.

Objective of the paper

To propose a compositional model for simulating CO_2 floods, including CO_2 solubility in water. The model allows hydrocarbons and CO_2 to exist in the oil and gas phases, whereas only CO_2 and water exist in the aqueous phase.

Methodology used

A cubic EOS is used to model oil- and gas-phase densities and fugacities. A new empirical correlation is presented for the solubility of CO_2 in distilled water as a function of pressure and temperature. Simulation results that compare reservoir performances with and without CO_2 solubility in water are presented.

Conclusions reached

1. The CO_2 solubility in water can be estimated with correlations within ±10 scf/STB for most CO_2 flood conditions;
2. About 10% of the CO_2 injected is dissolved in water and is unavailable for mixing with oil. The solubility effects are more pronounced for tertiary CO_2 floods than secondary CO_2 floods.

Comments

The study is not specific to fractured chalk reservoirs and since the effect of CO_2 solubility in water on CO_2 flood oil recovery will also depend on reservoir heterogeneity, rock and fluid properties, and injection/production history of the reservoir, the results cannot be easily generalised.

SPE 74335 (2001)

“Wettability Effects on Oil-Recovery Mechanisms in Fractured Reservoirs”

Authors: Graue, A.. Bognø, T., Baldwin, B.A., Spinler, E.A.

Contribution to the understanding of simulation of CO_2/CWI EOR for chalk fields

First to conduct experimental and simulation studies in parallel to predict oil-recovery mechanisms in fractured chalk as a function of wettability.

Objectives of the paper

The main objective was to determine the oil-recovery mechanisms at different wettability conditions. A secondary objective was to validate a full-field numerical simulator for prediction of the oil production and the in-situ saturation dynamics for the waterfloods.

Methodology used

1. Apply an ageing technique to several blocks of chalk to reproducibly alter the wettability of the rock. This was performed in sotck-tank crude oil at an elevated temperature for a selected period of time.
2. Test the validity of experimentally measured capillary pressure and relative permeability at strongly water-wet and moderately water-wet conditions.
3. Perform history matching for both the production profile and the in-situ saturation distribution.

Conclusion reached

1. For unfractured and fractured chalk, the oil recovery by waterflooding was similar for strongly water-wet chalk and moderately water-wet chalk.
2. Even at fairly low rates, more oil was mobilised by waterflooding chalk at less-water-wet conditions than recovered by spontaneous brine imbibition, but oil recovery for these flow rates was always less than recovered by strongly water-wet spontaneous imbibition.

Comments

This piece of work is specific to fractured chalks and therefore it focus on the importance of a fracture network in the dynamics of the recovery.

SPE 99650 (2006)

"Reservoir Conditions Laboratory Experiments of CO_2 Injection into Fractured Cores"

Authors: Darvish, G.R., Lindeberg, E., Holt, T., Utne, S.A., Kleppe, J.

Contribution to the understanding of simulation of CO_2/CWI EOR for chalk fields

First to show the importance of the cross-phase diffusion mechanisms to recover oil from the tight matrix block.

Objective of the paper

To quantify and understand the contribution of gravity drainage and diffusion for oil recovery during CO_2 injection in highly fractured under-saturated oil reservoirs.

Methodology used

Laboratory experiments at reservoir conditions were performed and the experiments were modelled using single porosity compositional simulators.

Conclusions reached

1. A very high oil recovery can be achieved by injection of CO_2 in fractured chalk reservoirs with high fracture intensity;
2. The lighter components with high diffusion coefficients were produced at the early stage of the experiments, while the heavier components with very low diffusion coefficient at the late stage.

Comments

The study is specific to fractured chalk reservoirs from the North Sea and the experiments presented have been used in other relevant papers.

SPE 111290 (2007)

"Experimental and Modeling Requirements for Compositional Simulation of Miscible CO_2-EOR Processes"

Authors: Shtepani, E.

Contribution to the understanding of simulation of CO_2/CWI EOR for chalk fields

1. First to couple the fluid phase behaviour with the flow through porous media;
2. First to integrate interfacial tension dependent relative permeability and capillary pressure in a dynamic description.

Objective of the paper

To discuss several aspects of miscible CO_2 flooding and to describe how these relate to the experimental and modelling studies required for a successful compositional simulation of miscible CO_2-EOR processes.

Methodology used

Review of the main steps of the modelling process: miscible CO_2, EOS characterisation and modelling, CO_2 injection core flood displacement and compositional reservoir simulation.

Conclusion reached

For a dynamic description of flow regions during miscible displacement process, interfacial tension dependent relative permeability and capillary pressure data are recommended.

Comments

No simulation result is provided. No description of required experiments for miscible gas injection is directly provided.

SPE 113436 (2008)

"Modeling CO_2 Injection: IOR Potential after Waterflooding"

Authors: Beremblyum, R., Calderon, G., Kollboth, L., Surguchev, L.M.

Contribution to the understanding of simulation of CO_2/CWI EOR for chalk fields

First to integrate in a single model all the known physical effects to model and to evaluate CO_2 injection after waterflooding.

Objective of the paper

To discuss the importance of correctly representing the physical effects when modelling miscible or immiscible CO_2 injection at the Ekofisk field (fractured chalk reservoir) and Gullfaks CO_2 injection compositional study.

Methodology used

The phenomena are successively presented and discussed using simulation results.

Conclusion reached

For each particular field case it is necessary to evaluate which effects are of importance and choose the right modelling and simulation approach. Numerical models may not account properly for diffusive and gravitational CO_2 transfer mechanisms.

Comments

This paper also presents the most common economic or logistical aspects that prevent projects from continuation.

SPE 139528 (2010)

"CO_2 EOR Potential in Naturally Fractured Haft Kel Field, Iran"

Authors: Alavian, S.A., Whitson, C.H.

Contribution to the understanding of simulation of CO_2/CWI EOR for chalk fields

First to propose a full field scale CO_2 injection model to estimate the CO_2 injection potential in a naturally fractured reservoir.

Objective of the paper

To study CO_2 recovery mechanisms in a naturally fractured reservoir.

Methodology used

Oil-recovery performance was quantified for the Haft Kel oil system using compositional modelling of a matrix block surrounded by a gas-filled fracture.

Conclusions reached

1. Grid refinement is needed for accurate modelling of nonequilibrium gas injection because of a complex gravity/capillary recovery mechanism with significant IFT and capillary pressure gradients;
2. Discussion on gravity/capillary recovery mechanism depending on CO_2 density compared to oil density.

Comments

The recovery mechanism happens only as a secondary recovery mechanism or as a tertiary recovery after dry gas injection.

SPE 139667 (2010)

"Tertiary Oil Recovery and CO_2 Sequestration by Carbonated Water Injection (CWI)"

Authors: Kechut, N.I., Riazi, M., Sohrabi, M., Jamiolahmady, M.

Contribution to the understanding of simulation of CO_2/CWI EOR for chalk fields

First to present an integrated experimental and numerical simulation study of tertiary CWI.

Objective of the paper

To identify the main mechanisms of oil recovery by the tertiary CWI.

Methodology used

The coreflood experiments are simulated using a compositional simulator with a properly tuned EOS model in order to evaluate the capability of an existing commercial reservoir simulator in modelling the CWI process.

Conclusions reached

1. CWI has potential to increase oil recovery form waterflooded reservoirs as evidenced from the coreflood experiments where the ultimate oil recovery by the tertiary CWI was consistently higher than that by water injection;
2. Oil swelling due to CO_2 diffusion into the oil leads to coalescence of the trapped oil droplets and fluid redistribution within the porous medium are among the main oil recovery mechanisms in the tertiary CWI process.

Comments

This paper presents a discussion about the importance of molecular diffusion at the field scale.

SPE 141937 (2011)

"Proper Modeling of Diffusion in Fractured Reservoirs"

Authors: Hoteit, H.

Contribution to the understanding of simulation of CO_2/CWI EOR for chalk fields

First to provide a solution for the cross-phase diffusion flux modelling.

Objective of the paper

To propose an alternative model based on the generalised Fick's law in which diffusion coefficients are calculated as a function of temperature, pressure, and composition.

Methodology used

Three diffusion models are reviewed and the drawbacks of the classical Fick's law are discussed. The diffusion coefficient model is introduced. Finally, the interface mass transfer problem is discussed.

Conclusion reached

The classical Fick's law neglects the off-diagonal diffusion coefficients that describe the component interaction and the dragging effect in multicomponent mixture. Neglecting the dragging effect may have major consequences in some applications that cannot be modelled accurately with the classical Fick's law.

Comments

Even if the classical Fick's law has limitations, it is still practical and simple so it may be used for some simulation purposes.

SPE 143005 (2011)

"Experimental and Numerical Evaluation of Carbonated Water Injection (CWI) for Improved Oil Recovery and CO_2 storage"

Authors: Kechut, N.I., Sohrabi, M., Jamiolahmady, M.

Contribution to the understanding of simulation of CO_2/CWI EOR for chalk fields

First to demonstrate that CWI increases oil recovery of waterflooded reservoirs above that of the plain water injection.

Objective of the paper

To demonstrate that CWI in both secondary and tertiary recovery modes can improve the oil recovery above the plain waterflooding.

Methodology used

Coreflood experiments are simulated using a compositional simulator with a properly tuned EOS model in order to evaluate the capability of an existing commercial reservoir simulator in modelling the CWI process.

Conclusions reached

1. The ultimate oil recovery by the secondary and tertiary CWI were consistently higher than that by water injection;
2. A new simulation approach is required to model the CWI process a the laboratory scale: molecular diffusion and convection of CO_2 from carbonated water into oil could not be accounted adequately by the simulator.

Comments

Experiments were performed for both secondary and tertiary CWI. Secondary CWI gives higher and earlier incremental oil recovery than the tertiary CWI process.

Appendix B—Capillary pressure sensitivity

Objective: justify that capillary pressure can be neglected and the impact of the assumption on the recovery process.

Capillary pressure measurements were not reported by Reslab or GEUS and it was decided not to include them in the building of the simulation models. However, in order to justify this choice it was decided to study the effects of capillary pressure at the core level. A set of capillary pressures curves from other Syd Arne reservoir samples was provided by GEUS. Since Reslab and GEUS cores were initially a single set of cores, these curves could be used for both experiments. The effects of the drainage capillary pressure curve are presented in **Fig. B1**.

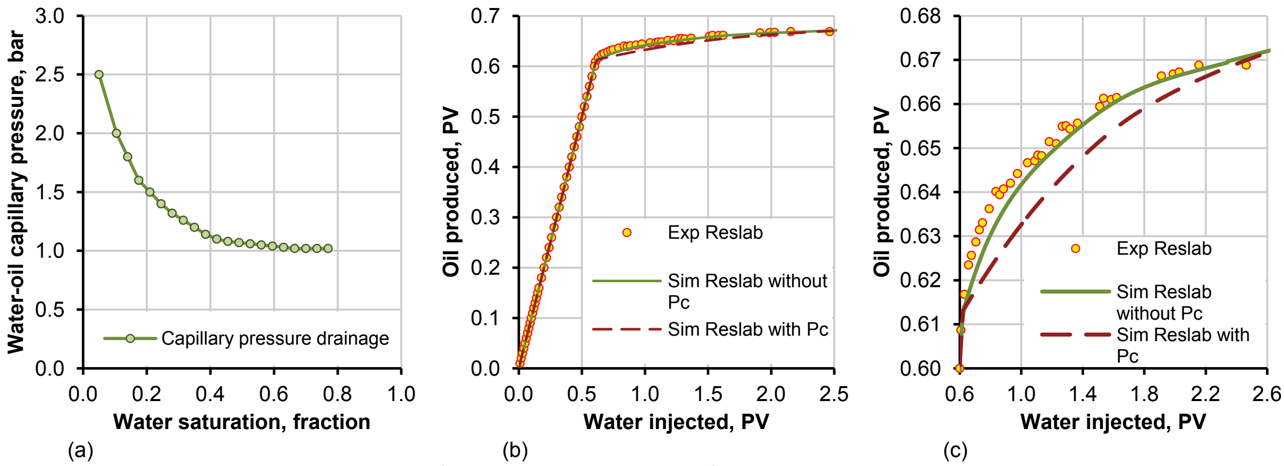

Fig. B1—(a) Drainage capillary pressure curve for a water-oil system. (b) Comparison between experimental and simulated (b) oil produced during waterflooding with and without capillary pressure for the Reslab core. Detail of the (c) secondary recovery phase with and without capillary pressure. Capillary pressure has a small impact on the recovery process and the ultimate recovery achieved remains the same.

The alteration of the oil production curve is hardly noticeable during waterflooding (**Fig. B1a and B1b**) and, in the end of the secondary phase, the amount of oil recovered is the same for both simulation cases. Thus, the choice is justified and the capillary pressure can be neglected given the injection pressures at the scale considered. The results are specific to Reslab core but they were extended to GEUS case as well.

Appendix C—Impact of heterogeneities

Objective: justify the use of a homogenous core and evaluate the impact of heterogeneities during waterflooding.

It is common to use composite cores to overcome the lack of long cores. Indeed, to ensure miscibility between the oil and the CO_2 phase, the core has to be as long as possible. To create a long core, several short cores can be mounted on top of each other. This solution is not optimal but if it is carefully performed it gives good results. It is common practice to order the cores in a way that the permeability is increasing from inlet to outlet. This way the capillary end effects become minimal.

Table C1 and Fig. C1 summarise the basic data for the coreplugs selected and illustrate the core model used, respectively. The heterogeneities were introduced in both permeability and porosity fields with the use of seven distinct regions. The contact between the cores was not modelled since the core end faces were cut in attempt to accomplish good contact between the individual cores.

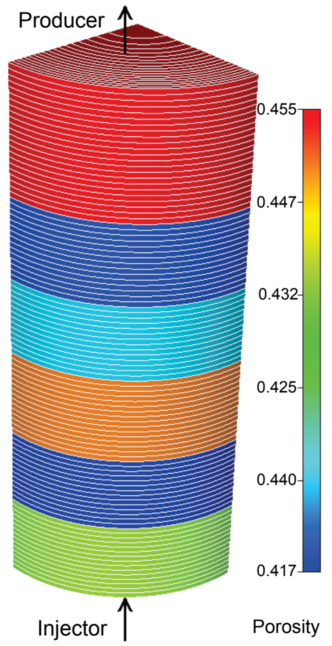

Fig. C1—Illustration of Reslab core model grid with heterogeneities in the porosity.

The impact of the heterogeneities was studied by simulating the waterflooding phase in Reslab core. The results are presented in **Fig. C2**. The match in the oil produced and specially the final recovery, are not as good as for the homogeneous core but this is due to the relative permeability curves which where specifically tuned for an homogenous core. However, the difference observed is acceptable (less than 1% PV of oil in the end) and shows that the assumption is valid. The pressure match is considerably improved, specially the phase prior to breakthrough (**Fig. C2b**) where the simulated curve falls between the experimental data.

Table C1—Basic data for the coreplugs selected for Reslab composite.

Core ID	Length (cm)	Number of layers	Porosity (fraction)	Absolute *k* (mD)
141	4.50	11	0.455	4.61
142	6.38	15	0.454	3.95
130	6.00	15	0.419	3.92
138	6.14	14	0.425	3.45
144	6.37	16	0.450	3.44
129	6.02	14	0.417	3.35
146	6.23	15	0.442	2.82

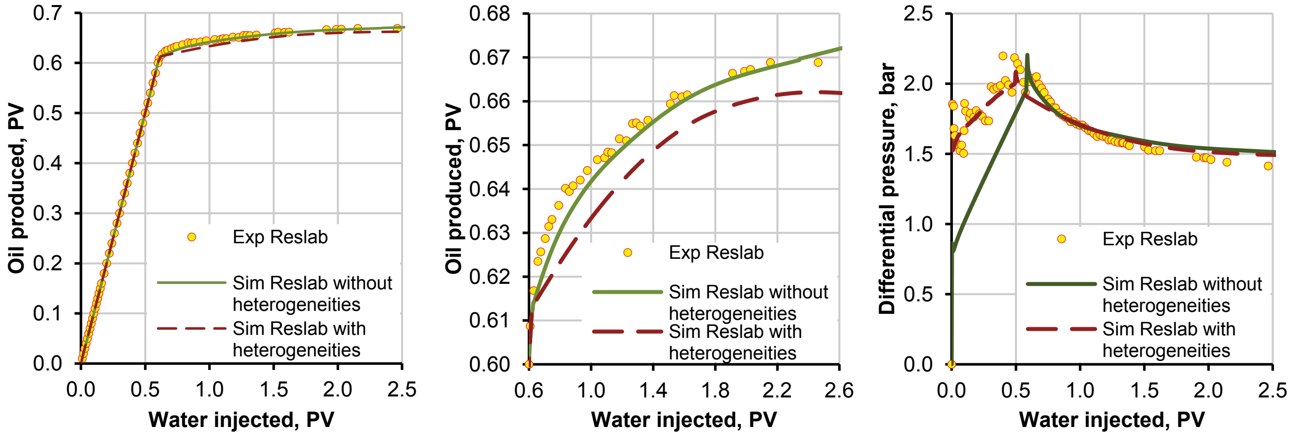

Fig. C2—Comparison between experimental and simulated (a) oil produced during waterflooding with and without CO_2 heterogeneities. Detail of the (b) secondary recovery phase with and without heterogeneities. (c) Differential pressure across Reslab core during waterflooding. The inclusion of heterogeneities improves the pressure match, specially the phase prior to breakthrough.

As a consequence, and in order to achieve the results in the most representative scenario, it was decided not to include the heterogeneities in the simulation model.

Appendix D—EOS data

Objective: detail the EOS parameters used to model the fluid.

EOS models that are applicable to simulate CO_2 injection in a compositional simulator have been developed for Syd Arne fluid (**Table D1**). Each fluid was represented using a total of 14 components. There are indications that the oil phase may split into two liquid phases as a result of CO_2 injection. Since the fluid description is to be used in a compositional reservoir simulator that can only handle one liquid phase, a fluid description has been chosen that will only provide one liquid phase at reservoir temperature independent of CO_2 concentration.

Table D1—EOS data for Syd Arne field fluid.

Component	Critical pressure (bar)	Critical temperature (°K)	Accentric factor	Molecular weight (g/mol)	Critical Z	Volume shift	P_{chor} (dyn/cm)
N_2	33.94	126.200	0.04000	28.0135	0.29049	0.034350	41.000
CO_2	73.76	304.200	0.22500	44.0098	0.27414	0.124571	78.000
C_1	46.00	190.600	0.00800	16.0429	0.28737	0.021107	77.300
C_2	48.84	305.400	0.09800	30.0698	0.28465	0.058382	108.900
C_3	42.46	369.800	0.15200	44.0968	0.28029	0.080639	151.900
C_4	37.55	421.759	0.18958	58.1237	0.27580	0.096082	189.647
C_5	33.78	466.019	0.24166	72.1506	0.26571	0.117663	230.436
C_6	29.69	507.400	0.29600	86.1780	0.26037	0.146034	271.000
C_7-C_9	27.62	559.391	0.50070	106.4854	0.31772	0.100901	310.461
C_{10}-C_{14}	19.53	626.907	0.64614	157.3280	0.27786	0.160127	432.927
C_{15}-C_{20}	15.08	705.481	0.85075	237.9939	0.28440	0.127163	621.836
C_{21}-C_{30}	13.29	787.397	1.07163	340.6187	0.32770	0.028188	866.964
C_{30}-C_{36}	12.52	875.098	1.27169	473.9164	0.39030	-0.114803	1171.265
C_{37}-C_{80}	12.26	968.198	1.32644	615.3128	0.47599	-0.250754	1541.172

Binary interaction coefficients

-0.0315												
0.0278	0.1200											
0.0407	0.1200	0										
0.0763	0.1200	0	0									
0.0700	0.1200	0	0	0								
0.0878	0.1200	0	0	0	0							
0.0800	0.1200	0	0	0	0	0						
0.0800	0.0800	0	0	0	0	0	0					
0.0800	0.0800	0	0	0	0	0	0	0				
0.0800	0.0800	0	0	0	0	0	0	0	0			
0.0800	0.0800	0	0	0	0	0	0	0	0	0		
0.0800	0.0800	0	0	0	0	0	0	0	0	0	0	
0.0800	0.0800	0	0	0	0	0	0	0	0	0	0	0

Appendix E—Consistency of the fluid model

Objective: justify the use of the fluid model by matching critical fluid properties.

A good match of all PVT data was achieved for Syd Arne reservoir fluid as it can be inferred from **Fig. E1**. The PVT data could suggest that a liquid-liquid split takes place at reservoir conditions when CO_2 is injected. The fluid description was used in a compositional reservoir simulator carried out with Eclipse. This reservoir simulator considers only one liquid phase and for this reason it was not found appropriate (numerical problems associated) to use a fluid description which makes the fluid split into two liquid phases.

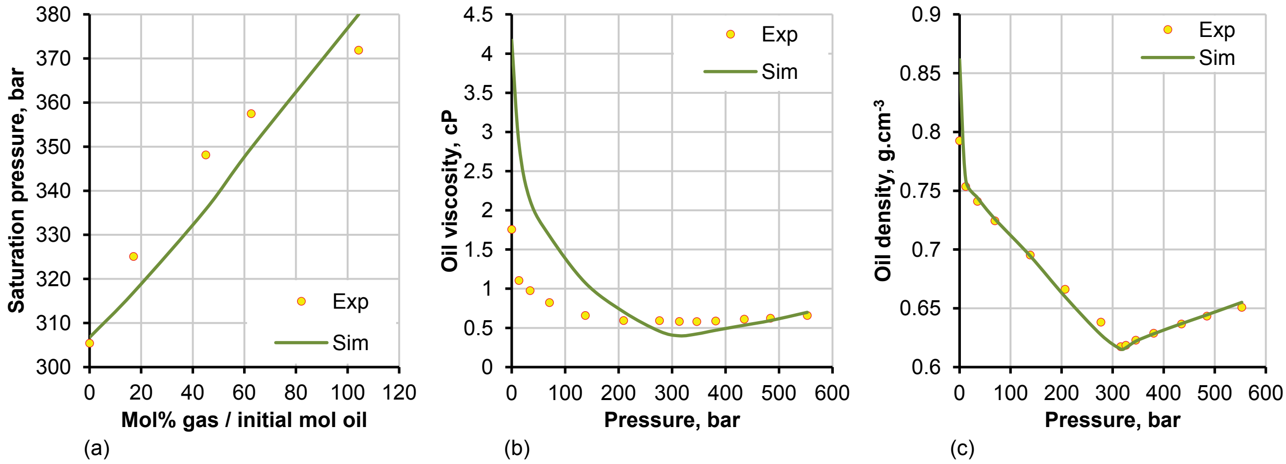

Fig. E1—(a) CO_2 swelling saturation point data and simulation results for Syd Arne. Experimental and simulated (b) liquid viscosities and (c) liquid densities for a differential liberation experiment at 115.5°C. The simulated viscosities are obtained with the LBC viscosity model. In general a good match is achieved between the model and the recombined Syd Arne sample.

It would have been desirable to have experimental data for the viscosity of the reservoir fluid mixed with CO_2. The LBC model has been used for the oil viscosity changes due to CO_2 dissolution and the water viscosity was set using the correlation developed by Bando et al. (2004).

Appendix F—Estimation of carbonated water viscosity

Objective: present the correlation to estimate the viscosity of carbonated water.

The correlation developed by Bando et al. (2004) was used to estimate the viscosity of the carbonated water at test conditions:

$$\mu_c = \mu_s \left[1 + \frac{x_c}{x_{cs}}(-4.069 \times 10^{-3}T + 0.2531)\right], \quad \text{(f1)}$$

where:

$\mu_c =$ viscosity of an aqueous NaCl solution containing CO_2, cP

$\mu_s =$ viscosity of an aqueous NaCl solution without CO_2 dissolved, cP

$x_c =$ CO_2 mole fraction of the solution partially saturated with CO_2

$x_{cs} =$ CO_2 mole fraction of the solution fully saturated with CO_2

$T =$ temperature, °C

This empirical correlation is reliable for temperature and pressure range of 30-60°C and 100-200 bar, respectively. There is no correlation to estimate the viscosity of the carbonated water for higher temperatures and pressures. Since the carbonated water is fully saturated with CO_2 the ratio $\frac{x_c}{x_{cs}}$ is equal to one. The results are summarised in **Table F1**.

Table F1—Calculated viscosity of CO_2 saturated brine.

Fluid	Pressure (bar)	Temperature (°C)	Viscosity (cP)
Brine	414	115	0.486
CO_2-saturated	414	115	0.382

Appendix G—Waterflooding results: GEUS experiments

Objective: determine the new set of relative permeability functions that allows GEUS experimental to be matched.

In order to keep the consistency in our study, the history match was constrained to be done by modifying the relative permeability curves as little as possible. **Fig. 4c** shows that the differential pressure across GEUS core could not be properly matched during the waterflooding phase and that the mismatch was beyond the error in pressure measurements. The objective was to perform a single history match without modifying the tuning parameters set for Reslab match.

Here, the new set of relative permeabilities needed to properly match both the final recovery and the differential pressure are presented (**Fig. G1a**).

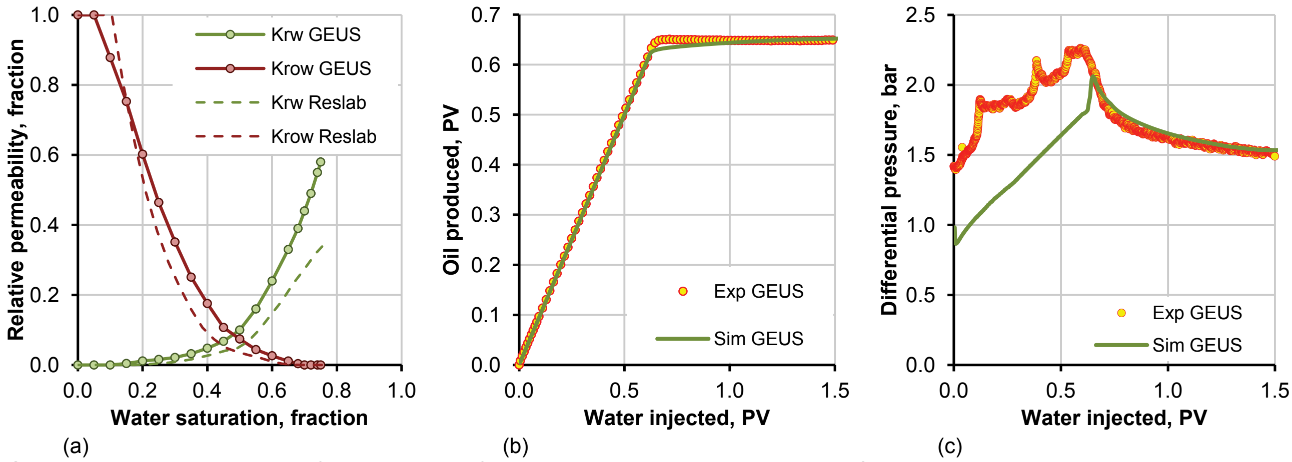

Fig. G1—(a) Relative permeability functions used for matching the experimental data. Comparison between experimental and simulated (b) cumulative oil produced and (c) differential pressure across the GEUS core. The differential pressure could be properly matched with a new set of relative permeability curves.

The simulation results obtained (**Fig. G1b and G1c**) are considered satisfactory in terms of history match but the relative permeabilities from Reslab and from GEUS differ too much to constitute a unique simulation model.

Appendix H—CO_2 injection without imposing residual oil saturation

<u>Objective</u>: demonstrate the inability of current simulators to handle gas injection.

Initially, the simulation was run without imposing a value for the residual oil saturation. This means that none of the methods like the alpha-factors or the bypassed oil was used. **Fig. H1** shows the results obtained in this case. The CO_2 is injected in large amounts and cannot be completely dissolved in the water or in the oil. There is a gas phase in the core and ECLIPSE 300 handles it improperly. Indeed, complete miscibility between oil and gas is assumed and, consequently, all the residual oil trapped in the core after waterflooding is recovered by the gas. Whenever oil and gas are in the same grid block, it is implicitly assumed that they get in contact and get mixed. Also, the instantaneous equilibrium assumption between all the phases present in a given grid block (oil, gas and water) leads to a faster recovery process. The breakthrough time is acceptably well matched since it is related to the injection rate and to the differential pressure more than to the mixing properties of the fluids. To conclude, the simulation results show that the compositional simulator overestimates the capabilities of CO_2 injection in the core and an alternative method properly representing the recovery mechanism is needed.

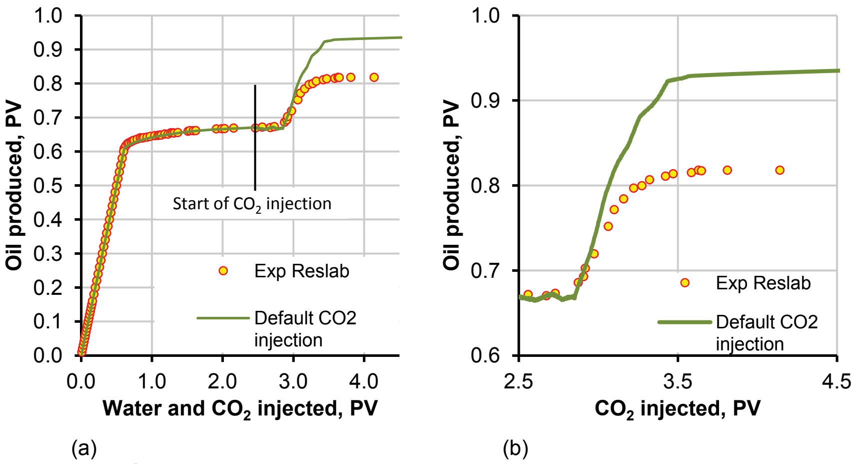

Fig. H1—Comparison between experimental and simulated (a) oil produced during pure CO_2 injection with ECLIPSE 300 default settings for gas injection. Detail of the tertiary recovery phase for (b) pure CO_2 injection (default settings). ECLIPSE 300 overestimates the final recovery.

Appendix I—Alpha-factors calculation

Objective: present the methodology to calculate the alpha-factors for a given oil residual saturation.

The alpha-factors method has been presented by Barker et al. (2004) and the method to generate them is summarised here. In the specific case of first contact miscible gas flood like CO_2 injection, the following analytical calculation can be used to impose a given residual oil saturation.

Because of the complete miscibility assumption of the current reservoir simulators, for any grid block where gas arrives the mixture forms a single phase whose composition can be expressed as it follows (for a given compound *i*):

$$z_i = V y_i^{inj} + (1 - V) x_i^{res} \, , \quad \text{(i1)}$$

where z_i is the overall mol fraction, y_i^{inj} is the mole fraction injected in gas phase, x_i^{res} is the mole fraction in the reservoir in oil phase and V is the vapour mol fraction.

Then the hydrocarbon phase is split in two parts: a non-flowing part (i.e. the residual oil saturation) and a flowing part:

$$z_i = F z_i^f + (1 - F) x_i^{res} \, , \quad \text{(i2)}$$

where F is the molar flowing fraction and z_i^f is the composition of the flowing part. With the ideal mixing assumption between the injected CO_2 and the reservoir oil, and fixed connate water saturation S_{wc}, we can also write:

$$F = 1 - \frac{\rho_O S_{orm}}{(V\rho_{CO_2} + (1-V)\rho_O)(1-S_{wc})} \, , \quad \text{(i3)}$$

where S_{orm} is the desired oil saturation.

For any given value of V, equations (i1)-(i3) can be solved for z_i^f, and the alpha-factors are then given by:

$$\alpha_{oi} = \alpha_{gi} = \frac{z_i^f}{z_i} \, . \quad \text{(i4)}$$

Taking a series of values of V covering the range 0 to 1 allows **Fig. I1** to be constructed and tabulated against the overall mol composition presented in **Table I1**.

Table I1—Phase compositions (mol fractions).

Component	Reservoir oil	Injected gas
N_2	0.002443	0
CO_2	0.000041	1
C_1	0.524121	0
C_2	0.071727	0
C_3	0.055956	0
C_4	0.040589	0
C_5	0.027625	0
C_6	0.019850	0
C_7-C_9	0.079007	0
C_{10}-C_{14}	0.075231	0
C_{15}-C_{20}	0.039943	0
C_{21}-C_{30}	0.028311	0
C_{30}-C_{36}	0.011500	0
C_{37}-C_{80}	0.023657	0

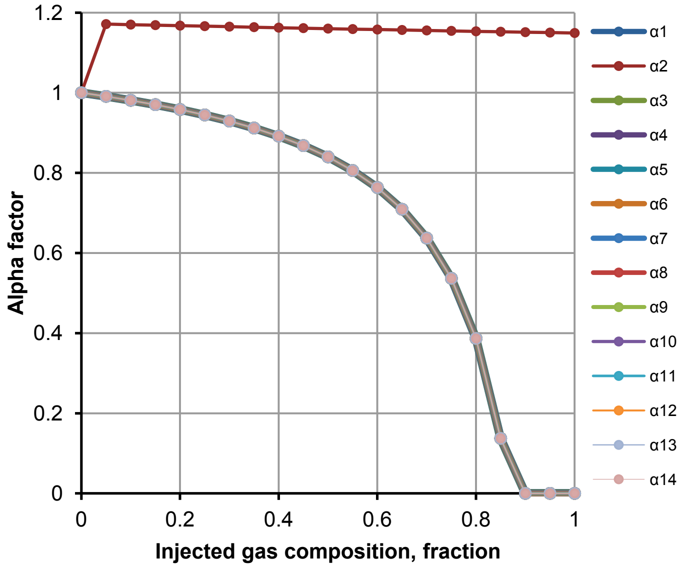

Fig. I1—Alpha-factors for target S_{orm}=12.9%. Since pure CO_2 is injected, all the components but CO_2 are slowed down with the same alpha-factor.

Appendix J—Wettability effect for very high permeability changes

Objective: prove that the difference in the production profile due to the wettability change is negligible even for high permeability changes.

The range of variation for the permeability used in the study was defined with the literature (Anderson 1987) since no experimental data is available. However, in order to validate our conclusions concerning the effect of wettability changes in the production profile, it was decided to explore the extreme water-wet case where the oil relative permeability becomes linear (**Fig. J1a**). A further decrease in the water relative permeability curve was not considered since the recovery in the simulation already happens faster than in the experiments and this change would have emphasised this tendency.

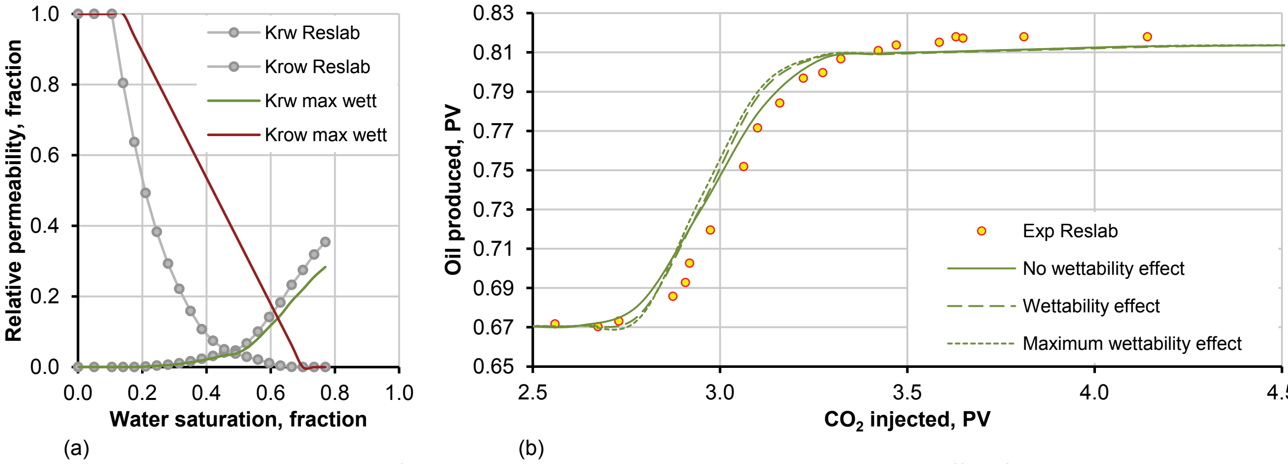

Fig. J1—(a) Relative permeability curves defining the boundaries used to include the wettability effect for high permeability changes. Comparison between experimental and simulated (b) cumulative oil produced with no wettability, extreme wettability and progressive wettabilitty. The difference in the production profile due to the wettability change is negligible.

Fig J1b shows very similar results to the ones obtained for the range of variation defined by the literature. Indeed, wettability changes have a negligible impact on the overall recovery profile (the ultimate recovery is not studied here) and our conclusion is still valid for this case.