Pore-scale modelling of CO\textsubscript{2}-brine flow properties at In Salah, Algeria

Olivier Lopez\textsuperscript{(a)*}, Nasiru Idowu\textsuperscript{(a)}, Alex Mock\textsuperscript{(a)}, Haakon Rueslåtten\textsuperscript{(a)}, Tony Boassen\textsuperscript{(b)}, Simon Leary\textsuperscript{(b)}, Philip Ringrose\textsuperscript{(b)}

\textsuperscript{a} NumericalRocks AS, N-7041 Trondheim Norway
\textsuperscript{b} Statoil R&D, N-7005 Trondheim Norway

Abstract

We present petrophysical data derived from pore-network modelling of CO\textsubscript{2}-brine pore systems from the Krechba CO\textsubscript{2} Storage Site (part of the In Salah Gas Joint Venture project operated by BP, Sonatrach and Statoil). The Carboniferous sandstone reservoir formation has relatively low permeability (c. 10mD) and is characterized by abundant and variable cementation – mainly quartz, patchy carbonates, grain-coating chlorites and pyrite. These petrographic characteristics make obtaining measurements and estimation of single and multiphase flow properties challenging. Pore-scale modelling is an important new tool which can supplement special core analysis measurements by providing single and two phase flow functions for a range of rock and pore types.

CO\textsubscript{2}/water relative permeability measurements have been carried out on four composite core plugs at reservoir conditions (95°C and 180 bars pore pressure). We have reviewed these experimental data and compared them to new predictions from several pore-scale reconstructions of the matching rock samples. First porosity, absolute permeability and formation factor were calculated and compared experimental data. Pore-networks were then extracted from the rock models and used as inputs to the simulation of CO\textsubscript{2}/water displacements. Primary drainage and waterflooding sequences were simulated to establish end-point saturations (i.e. \(S_{\text{wi}}\) and trapped CO\textsubscript{2} saturation), capillary pressure and relative permeability curves. Very good agreement was found between the experimental results and those derived from calculations of petrophysical parameters on rock models and multiphase flow simulations through their respective pore-networks.

Calculated permeability and porosity match the values estimated from the available logs, and the calculated average cementation exponent (\(m\)) for the three reconstructed samples is 2.05, comparable with the experimental value of 1.98. \(S_{\text{wi}}\) values obtained from the simulations range from 0.29 to 0.34, similar but slightly lower than those obtained from the steady-state experimental study - 0.39 to 0.44. The simulated residual CO\textsubscript{2} saturation ranges from 36\% to 44\%. The capillary trapping ensures that part of the injected CO\textsubscript{2} will stay disconnected as isolated CO\textsubscript{2} clusters in the pore space. These values are comparable to the residual gas saturation estimated from the experiments (from 15 to 40 \%). Differences between experiments and models can be related to differences in pore types which

\*Corresponding author. Tel.: +47 992 030 10.
E-mail address: olivier@numericalrocks.com.

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are better defined in the pore-network models. We conclude that pore-scale modelling is able to reproduce and supplement special core analysis experiments, even when the simulations are based on relatively simple assumptions, such as non-reactive and immiscible fluids. In addition, pore-scale modelling allows the correlation of end-points with the geometry, topology and morphology of the pore space of the rock, allowing us to improve the basic understanding of CO2 trapping mechanisms in heterogeneous formations.

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1. Introduction

Geologic sequestration of CO2 can be accomplished by separating CO2 from flue gases and subsequently injecting it into a variety of storage reservoirs, including brine aquifers, producing or depleted oil and gas reservoirs, and coal beds [1,2]. Depending on the storage reservoir of interest and the composition of the waste gas stream (pure CO2 vs. mixtures of CO2 with other gases), injection of CO2 in geologic formations may give rise to a number of physical and chemical phenomena, such as miscible or immiscible displacement of native fluids, dissolution of injected fluids into reservoir fluids, changes in effective stress with associated porosity and permeability change and the possibility of inducing seismic activity, chemical interactions between fluids and solids, and nonisothermal effects. The In Salah region has over 30 gas fields in the gas-prone Ahnet Basin, which is situated in the central part of Algeria. At Krechba, one of the several producing gas fields in the In Salah Gas project (operated by BP, Sonatrach and Statoil), a carbon dioxide injection project was started in 2004, and has to date injected over 3 million tones of CO2. One of the key issues in process simulation is the fluid mechanics of single and multi-phase flow when CO2 is injected into aquifers, oil reservoirs, or natural gas reservoirs [3,4]. Pore scale modelling is an important new tool which can supplement conventional and special core analysis (CCA and SCAL) measurements by providing single and two phase flow functions for a range of rock and pore types. It includes rock modelling, calculation of petrophysical properties, 2-phase fluid flow simulations and comparison of predicted results with laboratory data. In the present work, an integrated pore-scale modelling approach was used to reconstruct 3 reservoir rock samples from Krechba field. Predicted results were then compared to available CCA and SCAL data.

2. Methodology

2.1. Pore scale reconstruction of reservoir rocks

Thin sections were prepared from end-cuts of all samples. They were imaged with a backscatter scanning electron microscope (BSEM) at a resolution of 2.15µm/pixel. Digital images were analyzed to provide input data for the geological reconstruction of the samples. Data obtained from image analysis are porosity, fractions of mineral constituents such as clay minerals, other mineral cements (especially carbonate) and the size of cement patches, heavy minerals (e.g. pyrite) and the grain size distribution. The spatial distribution of clay minerals and the amount and distribution of secondary porosity are assessed qualitatively on the BSEM images. Grain sizes are extracted by a distance transform and maximum inscribed circle algorithm applied on the grain matrix images. An empirical correlation is applied to correct for stereological effects [5]. The fraction of clay minerals is corrected for partial volume effects by applying a granulometric filter [6]. The results of image analysis form a set of input parameters to reconstruction algorithms for the geological rock forming processes sedimentation, compaction and diagenesis [7]. Local distribution functions are applied to assess the variation of porosity and fraction of clay minerals within the thin section BSEM images. This variation is accounted for by reconstructing three model realizations for each sample (M1, M2 and M3) where M1 has average properties and the other two cover the lower and higher property range, respectively. Figure 1 shows an example of this process for one of the samples. One of the challenges in this process is the correct characterization of thin clay mineral which lines the pores. These are represented in the model realizations as clay voxels with sub-resolution microporosity. The microporosity is assumed to be impermeable during the flow simulations. Minerals were mainly identified using X-ray elemental analysis of BSEM samples.
using Energy-dispersive spectroscopy (Figure 2). All 3D rock models are represented as uniform grids with a finite size for each grid cell (voxel). Predicted petrophysical properties include porosity and absolute permeability. Porosity is obtained from the number of pore voxels (intergranular porosity) and sub-resolution microporosity in clay voxels (total porosity). Absolute permeability is computed using Lattice-Boltzmann simulations directly on grid models [8,9].

The reconstructed rock models were simplified into pore network models. Crucial geometrical and topological properties were retained, while the data volume was reduced to allow timely computation [7]. In pore network modelling, local capillary equilibrium and the Young–Laplace equation are used to determine multiphase fluid configurations for any pressure difference between phases for pores of different shape and with different fluid/solid contact angles. The pressure in one of the phases is allowed to increase and a succession of equilibrium fluid configurations are computed in the network. Then, empirical expressions for the hydraulic conductance of each phase in each pore and throat are used to define the flow of each phase in terms of pressure differences between pores. Conservation of mass is invoked to find the pressure throughout the network, assuming that all the fluid interfaces are fixed in place. From this, the relationship between flow rate and pressure gradient can be found and hence macroscopic properties, such as absolute and relative permeabilities, can be determined [5].

The following displacements were simulated on extracted pore networks of the reconstructed models: CO₂/water primary drainage to initial water saturation \( S_{wi} \), and waterflooding to residual CO₂ saturation \( S_{gr} \). At the pore scale, it is assumed that the displacement processes are quasi-static and capillary dominated. This is a reasonable assumption for low capillary number processes that are typical of most reservoir displacements.

3. Results and discussion

3.1. Geological Description

Sample JIP1: This well-sorted, fine to very fine grained sandstone has well rounded grains and is very heterogeneous. Areas with highly-cemented fractures alternate with areas of relatively high intergranular porosity of 11.4%. Areas with good porosity have chlorite grain coatings (which have inhibited quartz cementation during diagenesis). Some porosity appears to be secondary porosity originating from grain dissolution. About 10.5% of the mineral phase consists of clay. The fractures are filled with carbonate cement (mainly Ankerite). Heavy minerals (e.g. siderite) show a patchy distribution.

Sample JIP5: This moderately to well sorted, fine-grained sandstone is heterogeneous. Several different rock types can be recognized in the SEM image: relatively porous zones (with chlorite coatings), strongly cemented zones with mainly ankerite and barite cements and some areas with extensive quartz cementation. The intergranular porosity of the porous rock type is about 7.5%.

Sample JIP6: This well sorted, fine grained sandstone has well rounded grains. In parts, it shows extensive cementation (mainly ankerite, dolomite and kaolinite). In part, the porosity is well preserved, again due to chlorite grain coatings giving an observed intergranular porosity of 9.9%. A number of heavy mineral patches also occur. About 9.4% clay minerals occur in the sample.

3.2. \( S_{wi} \) and \( S_{gr} \)

Clay and mica subdivide pores and create micro-porosity. Figure 3 shows the correlation between average fraction of clay and mica in the rock models and \( S_{wi} \). There is a strong correlation between these two parameters. The irreducible water saturation is depending on the following parameters: connate water associated with clay minerals, water present in small pores, films on pore walls and in corners of pores. The latter is a function of capillary pressure and the shape of the pores, i.e. the half angle of corners and inscribed radius of the pore. However, the strong correlation between \( S_{wi} \) and the sum of clay fraction and mica fraction suggests that most of \( S_{wi} \) is associated with clays therefore there is only a minor contribution from bulk and film water in intergranular pores (approximately 1%).

The basic bond breaking mechanisms in water wet systems are snap-off and pore-body filling. Snap-off is a bond rupturing mechanism that occurs as a result of a capillary driven instability of the wetting film inside a pore throat.
Pore-body filling is the process by which water in two or more throats displaces non-wetting phase from the connecting pore body. Both magnitude and distribution of waterflood residual CO₂ depend strongly on the dominant bond breaking mechanism. If snap-off is the preferred mechanism, significant CO₂ disconnection and trapping occurs. The bulk of the residual CO₂ is trapped as numerous small blobs occupying only a single or a few interconnected pore bodies. Therefore the residual CO₂ saturation in the water swept regions is high. However, if pore body filling is the dominant mechanism, CO₂ tends to be trapped in large clusters being bypassed by water with little or no CO₂ remaining in the water swept regions. The ease by which these bond breaking mechanisms trap CO₂ is of course dependent on the overall connectivity of the pore network (i.e. the coordination number \( Z \)). To summarize, in water-wet systems where CO₂ can only flow as bulk fluid, the two main parameters that govern the residual CO₂ saturation are pore network connectivity and aspect ratios. Obviously, \( S_{gr} \) increases with decreasing pore network connectivity, irrespective of the preferred bond breaking mechanism.

### 3.3. Comparison with experimental data

CO₂/water primary drainage displacement to initial water saturation, \( S_{wi} \) and then waterflooding to residual gas saturation, \( S_{gr} \) were simulated. The input data used during the flow simulations are summarized in Table 1. The predicted average relative permeability and capillary pressure curves for the three samples were compared with experimental steady-state relative permeability curves obtained from three composite cores at reservoir conditions (95°C and 185 bars) as shown in Figure 4 and Figure 5. It should be noted that the depths, porosities and permeabilities of the composite cores are different from those of the modelled samples as shown in Table 2 but represent the same rock type as the ones reconstructed.

**Table 1 – Properties of the fluids used for both experiments and simulations**

| Fluid Property | Unit | Value |
|----------------|------|-------|
| Water density  | [kg/m³] | 1040  |
| CO₂ density   | [kg/m³] | 446   |
| IFT\(_{CO₂/w} \) | [dynes/cm] | 33.9  |

**Table 2 – Single and two phase properties of the selected samples (\(^*\) for reconstructed samples)**

| Sample ID | Well | Depth [m] | Avg. Porosity [frac.] | Avg. Abs. Perm. [mD] | \( S_{wi} \) | \( S_{gr} \) |
|-----------|------|-----------|-----------------------|----------------------|----------------|----------------|
| Comp. core1 | Kb-6 | 1768.87 | 0.190 | 15.90 | 0.39 | N.C. |
| Comp. core2 | Kb-2 | 1758.63 | 0.200 | 5.12 | 0.40 | 0.14 |
| Comp. core3 | Kb-6 | 1763.29 | 0.190 | 0.98 | 0.44 | 0.34 |
| JIP1\(^*\) | Kb-5 | 1790.70 | 0.165 | 16.50 | 0.32 | 0.41 |
| JIP5\(^*\) | Kb-9z | 1793.90 | 0.099 | 5.80 | 0.29 | 0.44 |
| JIP6\(^*\) | Kb-9z | 1816.80 | 0.139 | 6.60 | 0.34 | 0.36 |
| Plug 4 | N.C. | 1758.58 | 0.210 | 21.70 | 0.092 | N.C. |
| Plug 6 | N.C. | 1762.80 | 0.200 | 30.50 | 0.107 | N.C. |
| Plug 7 | N.C. | 1765.13 | 0.180 | 1.36 | 0.167 | N.C. |

The primary drainage relative permeability curves for the three samples show the same trend: sudden drop of the water relative permeability due to low connectivity of the pore network and large uncertainties in the gas relative permeability after the breakthrough. Once the gas (non-wetting phase) breakthroughs, bulk flow of water (wetting phase) will be reduced and consequently the water relative permeability will quickly tend to zero. Figure 4 shows that there is a good match between the predicted average and experimental water relative permeability curves while the match is fair for gas relative permeability. Also, the shape of the experimental and predicted gas relative...
permeability is the same – straight line and further confirms the low connectivity of the pore network models and the composite cores.

Waterflood simulations were performed to establish the efficiency of the pore-scale trapping mechanism, by rendering the CO₂ immobile as residual non-wetting phase (capillary trapping). The residual CO₂ saturation ranges from 36% to 44%. These values are comparable to the residual gas saturation estimated from the experiments (from 15 to 40%).

N₂/water capillary pressure measurements were performed on three plugs (Plugs 4, 6 and 7 – Table 2) using Porous Plates method that lasted for 8 months due to very long stabilization time on several of the pressure steps. The predicted CO₂/water capillary pressure (Pₖ) and Leverett J function (J) results for the three modelled samples were scaled up to N₂/water results using N₂/water interfacial tension of 64.6 mN/m [10] and compared with experimental N₂/water Pₖ data obtained on the three plugs. Figure 5(a) compares the predicted Pₖ curves with experimental data at a pressure of 3 bar (μm resolution) and shows that the experimental Pₖ plots for Plug 4 and Plug 6 fall within the predicted Pₖ plots for samples JIP5 and JIP6. J-function plots eliminate the differences in the absolute permeability and porosity values and Figure 5(b) shows a very good match between the J-function plots of Plug 4 and JIP6 up until a water saturation, Sₘₗ = 0.57. From Sₘₗ = 0.34 to Sₘₗ = 0.57, the match is not good and this may be due to the facts that plug 4 and sample JIP6 are not from the same depth and well and the tightly cemented part of sample JIP6 is not included in the modelled area.

4. Conclusion

Several properties of rocks influence the displacements of fluids through the reservoir. In oil and gas exploitation as well as CO₂ storage, the properties are usually obtained from CCA and SCAL and are preferentially used for reservoir description and simulation. These procedures are relatively time consuming and are applied on a very small number of drilled cores. But accurate prediction of performance of reservoir requires depiction of the variability of the flow properties. The impact of pore structure on single phase and multiphase flow response of reservoir rocks is then crucial. The prediction of petrophysical and multiphase flow properties from direct pore-scale modelling has been investigated for three different samples from the Krechba field at In Salah (Algeria).

Very good agreement was obtained between pore-scale modelling derived properties and available experimental data throughout the studied data set. It is concluded that the applied integrated pore-scale modelling approach yields reliable and consistent data for CO₂/brine systems even when the simulations are based on relatively simple assumptions, such as non-reactive and immiscible fluids.

Relative permeability curves are important for CO₂ storage modelling and results from the simulations show a very good agreement with the laboratory experiments in terms of shape and end-point saturation (Sₘₗ and Sₚ). It has been also shown that the relative permeability end-points can be easily correlated with the geometry, topology and morphology of the pore space of the rock. It is of great importance for a fast and reliable characterization of the reservoir as these residual saturations play a critical role in CO₂ storage modelling by shifting the saturation range for which the CO₂ plume is mobile.

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5. References

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6. Figures

Figure 1: The pore space at Krechba: a) SEM image (using combined BSEM and X-ray) from sample JIP5 showing quartz grains (green), chlorite grain coatings (blue) and pores (black) (Field of view is c. 200 μm), b) Pore-scale geomodel for sample JIP5 on the right (Field of view is c. 3000 μm).

Figure 2: Elemental analysis of sample JIP1 using Energy-dispersive spectroscopy (EDS), indicating iron rich chlorite coatings (green) and ankerite cementation (pink).
Figure 3: a. formation resistivity factor (FRF) as a function of total porosity for the reconstructed samples (open squares) from the experiment (open circles and dotted line) and for common sandstone (plain line). b. Initial water saturation versus clay + mica fraction for the reconstructed samples. c and d. Residual CO₂ saturation after waterflooding versus average aspect ratio and average connectivity respectively.
Figure 4: comparison of the predicted average primary drainage relative permeability curves with experimental data; (a) linear plot and (b) semi-log plot.

Figure 5: comparison of the predicted: (a) capillary pressure curves for the three modelled samples with experimental data from the three plugs; and (b) J-function plot for modelled sample JIP6 with experimental data of Plug4.