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Public abstract

This report is part of the research project MiReCOL (Mitigation and Remediation of CO_2 leakage) funded by the EU FP7 program[1]. Research activities aim at developing a handbook of corrective measures that can be considered in the event of undesired migration of CO_2 in the deep subsurface reservoirs. MiReCOL results support CO_2 storage project operators in assessing the value of specific corrective measures if the CO_2 in the storage reservoir does not behave as expected. MiReCOL focuses on corrective measures that can be taken while the CO_2 is in the deep subsurface. The general scenarios considered in MiReCOL are 1) loss of conformance in the reservoir (undesired migration of CO_2 within the reservoir), 2) natural barrier breach (CO_2 migration through faults or fractures), and 3) well barrier breach (CO_2 migration along the well bore).

This report summarizes the studies regarding the topic “Reservoir pressure management” as part of the overarching research task “ Migration management”, and is focused on three major fields: 1) Feasibility test and numerical modelling of CO_2 back-production as remediation measure to reduce reservoir pressure and induce inward directed flow in case of lateral leakage beyond spill point. 2) Feasibility test and numerical modelling of brine/water withdrawal as remediation measure to reduce reservoir pressure and create pressure gradients with directed flow in case of

[1] More information on the MiReCOL project can be found at www.mirecol-co2.eu.

lateral leakage beyond a spill point. 3) Assessment and test of novel approaches and sensing technologies to manage reservoir pressure. This report represents a first step to investigate the conditions that require the deployment of pressure management techniques as corrective measures in case of undesired CO_2 migration in the subsurface.

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1. INTRODUCTION

This report is part of the research project MiReCOL (Mitigation and Remediation of CO_2 leakage) funded by the EU FP7 programme[2]. Research activities aim at developing a handbook of corrective measures that can be considered in the event of undesired migration of CO_2 in the deep subsurface reservoirs. MiReCOL results support CO_2 storage project operators in assessing the value of specific corrective measures if the CO_2 in the storage reservoir does not behave as expected. MiReCOL focuses on corrective measures that can be taken while the CO_2 is in the deep subsurface. The general scenarios considered in MiReCOL are 1) loss of conformance in the reservoir (undesired migration of CO_2 within the reservoir), 2) natural barrier breach (CO_2 migration through faults or fractures), and 3) well barrier breach (CO_2 migration along the well bore).Storing CO_2 geologically in saline reservoirs or depleted gas fields to reduce emissions into the atmosphere is one of the options to mitigate climate change. Storing CO_2 leads to an increase in formation pressure, which is with regard to saline reservoirs, the major risk to damage the storage complex and for CO_2 leakage. Therefore pressure management is an important part of day-to-day CO_2 storage operation. Pressure management can also be used to mitigate the effects of undesired migration of CO_2 in the subsurface. As part of the MiReCOL project's overall aim to develop guidelines on corrective measures to mitigate the effects of undesired CO_2 migration, this report represents a first step to investigating the conditions that require the deployment of pressure management techniques in case of undesired CO_2 migration in the subsurface.

Pressure management is closely connected to the individual configuration of geology and technical site development. There are numerous relevant geological parameters and technical configurations such that a universal solution does not exist. This is typical for highly nonlinear multi parameter systems (Moore and Doherty, 2006). To account for the almost infinite number of combining different technical actions in different geological conditions, the research in the MiReCOL project follows a top down approach. This report consists of 4 sections.

In the first section (chapter 2) the main geological settings and technical conditions will be assessed on a general level. The principal factors of influence will be named and identified such that operators can deduce guidelines for assessing a storage reservoir and estimate the reservoir behavior. This work is carried out in the research topic "Selection of scenarios" of MiReCOL.

In the second section (chapter 3) modeling studies are presented to show exemplarily procedures of pressure management. These studies are about existing field sites. For example, the back production of CO_2 is an important option to lower reservoir pressure and the first field experiment has been carried out at the pilot site Ketzin. An alternative approach is demonstrated by modelling of CO_2 injection scenarios at the P18 field in the Netherlands.

The third section (chapter 4) addresses individual processes related with the general pressure buildup. The reservoir behavior during back production is expected to differ considerably from injection operation. The difference is based on hysteresis effects on the pore scale and well effects. These investigations are closely connected with the back

[2] More information on the MiReCOL project can be found at www.mirecol-co2.eu.

production test at the Ketzin pilot site and will be studied on the laboratory and the reservoir scale, respectively. In addition to more traditional methods that are described above, a novel method of reservoir pressure management is presented. Therein, the infiltration of nanoparticles in the subsurface is applied with the purpose of either increasing mixture of the phases or the dissolution of CO_2.

The fourth section (chapter 5) is a short overview on industry practice on pressure management and field measurement and instrumentation.

2. PRINCIPAL FACTORS RELEVANT FOR PRESSURE BUILD UP IN THE RESERVOIR AND COUNTER MEASURES

1. Reservoir boundaries: The type of boundary conditions is the most important criterion for type and management of pressure buildup. Brine extraction to counteract pressure buildup gains importance the more isolated a reservoir is from surrounding aquifers (Zhou et al., 2008). In case of closed boundary conditions the pressure increases rapidly. Only small amounts of CO_2 can be stored. Open systems are hydraulically connected over large areas wherefore the pressure buildup can dissipate laterally and larger amounts of CO_2 can be stored. The application of pressure relief wells that allow pressure dissipation by means of fluid discharge is therefore of essential relevance for closed systems. The volume of brine production required to reduce seismic and leakage risks to near zero was shown to be approximately equal to the volume of injected CO_2 (Buscheck et al., 2011). But also for semi-closed and open systems also beneficial effects may be obtained. For open systems Wiese et al. (2010) identified the principal factors affecting injection pressure.
2. Interaction of injection wells: The injection pressure decreases with the number of wells to which the CO_2 flux is partitioned. Large CO_2 projects may include a high number of injection wells which affect each other and have a similar effect as semi-closed or closed boundary conditions. As a first approximation their interaction can be described with the superposition theory, but also adapted analytical solutions for simulation of pressure build up with CO_2 injection and brine withdrawal already exist (Mijic et al., 2012). Generally, it has to be considered that the additional benefit decreases continuously with the number of injection wells.
3. Type of pressure buildup: The total pressure buildup consists of two parts: Dynamic and static pressure. The dynamic pressure is induced by the injection well and dissipates through migration of the over-pressured reservoir fluid to regions with a lower hydraulic potential. After this equilibration only the static pressure remains, which is induced by buoyancy of the injected CO_2. Pressure management addresses primarily dynamic reservoir pressure (Zhou and Birkholzer, 2011) since it is typically higher than static reservoir pressure and can be counteracted more efficiently due to its transient nature.
4. Type of storage: Saline aquifers and former gas fields are the two most common storage options Saline aquifers are completely saturated with reservoir fluid prior to injection, during injection the brine is replaced by CO_2. The pore space in former gas fields typically is occupied with residual gas, while reservoir fluid may be present below the gas water contact and residual capillary water may occupy the lower pore spaces. Structural trapping of the caprock is inherent to both storage types, the caprock counteracts the buoyancy of the gas phase and ensures the containment of the stored CO_2.The other trapping mechanisms (capillary trapping, solubility trapping, mineral trapping) differ between the storage types. The Ketzin reservoir is an example for a saline aquifer storage (Task 4.3), while the P18 field is an example for a former gas field (Task 4.4)
5. Caprock integrity: For a former gas fields the caprock has proven to prevent gas migration within geologic time scales, and therefore is likely to form an effective barrier. However, changing pressure conditions during exploitation

potentially may induce open fractures and migration paths. The caprock of a saline aquifer may comprise open fractures and weak zones which have to be identified with geophysical methods. The pressure management has to take into account position and type of the different potential leakage pathways. Lowering the reservoir pressure by removing water or other fluids from the storage structure is one of the remediation options suggested by Benson and Hepple (2005) for CO_2 storage projects within the scenario of leakage up faults, fractures and spill points. Birkholzer et al. (2012) demonstrated the use of brine extraction to minimise pressure build-up at specific locations, such as near a fault zone.

6. Reservoir fluid: The reservoir fluid increases storage safety through capillary forces and dissolution, wherefore both processes are mainly relevant for saline aquifers. This has consequences on potential remediation options. Brine extraction is always a management option for saline aquifers, while it may not be feasible for former gas fields. In contrast, the mobility of gas is higher for former gas fields, therefore, a rather faster release of CO_2 is possible. While the presence of reservoir fluid enhances the storage safety, corresponding effect of water coning may impair the controlled CO_2 release remediation (see also chapter 4, Figure 11).
7. Brine disposal: The practical feasibility of pressure management is closely related to the disposal of extracted reservoir fluid. The main environmental concern is the typically high salt concentration. In the absence of other contaminants, the discharge to the sea is a simple disposal option. Breunig et al. (2013) assessed whether recovered heat, water, and minerals from large volumes of extracted brine can turn the brine into a resource. Brine extraction was also shown to create economic value via beneficial use of treated brine and reduce other costs for CO_2 storage, thereby achieving higher dynamic storage capacity of large-scale CO_2 storage (Bourcier et al., 2011; Maulbetsch and DiFilippo, 2010). Some studies suggest the reinjection in different geological horizons. Depending on the local conditions the effort for brine disposal may preclude the application of pressure management through brine extraction.

The current state regarding the selection of models and scenarios from the data base has been drawn in another report of MiReCOL. The aim of the modelling work is to get a deeper understanding of physical and mechanical parameters which accompany a pressure reduction regime. The requirements to these models and their performance for the various pressure management applications are still under investigation.

3. NUMERICAL MODELLING OF PRESSURE MANAGEMENT

3.1 Numerical Modelling of the Ketzin pilot site

The potential of CO_2 back production and brine withdrawal to reduce the reservoir pressure and divert the CO_2 plume will be assessed. Hypothetical brine extraction wells will be implemented into the applied Ketzin model.

Description of the model selected

A simple inverse model exists for the Ketzin Pilot site. It integrates three hydraulic tests and the first thirty days of CO_2 injection. The model focuses on the joint inversion of the observed pressure during the hydraulic test, injection pressure in the CO_2 injection well and the arrival time of CO_2 arrival data. It contains 30 free parameters and is feasible to model channeling effects due to layered permeability (Figure 1). It is an advanced continuation of the hydraulic modelling work (Chen et al., 2014) and a necessary complement for description of near wellbore modelling effects and consistency with hydraulic testing. These aspects focus on the near wellbore area and are not captured by the former large scale Ketzin reservoir modelling work (Kempka and Kühn, 2013).

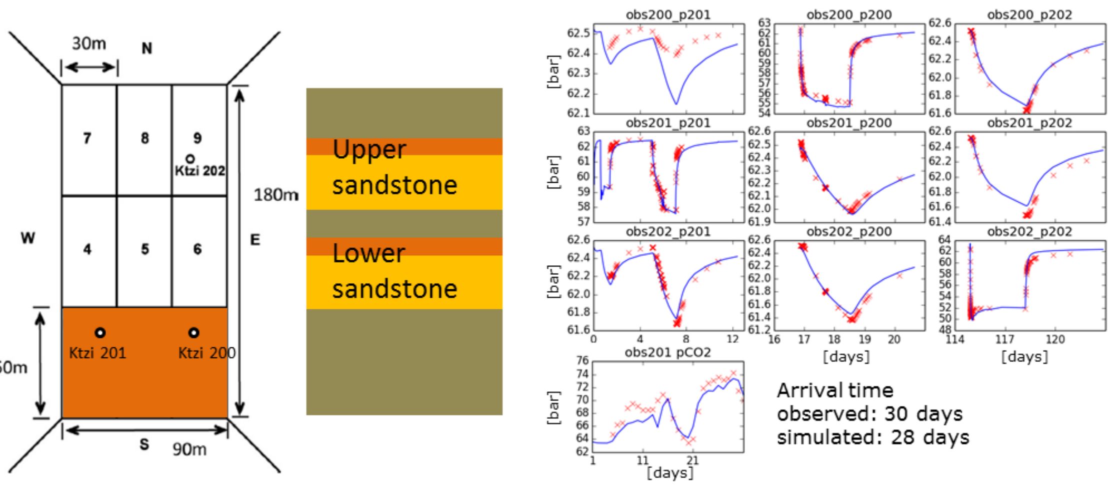


Figure 1: Simple inverse reservoir model including single phase hydraulic data, multiphase injection pressure and arrival time. The orange regions show sandstone areas with high permeability that act as channels for preferential CO_2 flow.

Modelling approaches that consider only single phase hydraulic tests indicate a region of low permeability between the injection well Ktzi 201 and observation well Ktzi 200. Multiphase simulations of CO_2 injection in contrast indicate a high permeability between both wells. Single phase simulations predict a higher effective permeability than constrained multiphase simulations. The problem is resolved by joint inversion of one single and one multiphase model. It is crucial for this calibration to develop a geological concept that contains the relevant features and allows to reproduce the different type of observations. In general, the large amounts of data that are recollected from the tests site represent different aspects of the same geological features. Joint inversion is the only promising approach to achieve a comprehensive interpretation to integrate pressure management in the context of other management objectives, e.g. flow diversion and back production (also called venting).

Hypothetical brine extraction wells will be implemented into the inverse Ketzin model. The potential of brine extraction to reduce the reservoir pressure and to divert the CO_2 plume will be assessed. Different spatial well configurations will be tested for the most effective application of the remediation measure. Due to the high content of dissolved minerals the proper disposal of extracted brine is expected to be expensive if discharge to the sea is not possible. In case that preliminary simulations show the withdrawal is far from economic viability, a change of the focus is suggested.
In 2015, a brine injection test is carried out at the pilot site in Ketzin. Brine injection enhances residual trapping and therefore increases the safety of CO_2 storage. Although this brine injection test is not directly in the scope of the research topic "Pressure management", the safety of CO_2 storage is an elementary remediation measure and generally relevant for the MiReCOL project. It appears worthwhile to slightly shift the focus and consider performing dynamic flow simulations on the Ketzin brine injection field test. Moreover, collaboration with another research topic of MiReCOL, "CO2 flow diversion", appears to be advantageous.

3.2 Numerical Modelling of the P18 field

The rate of brine withdrawal required from the existing wells around a CO_2 injection well in a storage structure where pressure build up due to CO_2 injection is "higher than expected". In order to relieve the pressure, various combinations of brine withdrawal through available wells in the gas reservoir will be examined.

Description of the model selected

The storage complex must exhibit pressure build-up due to CO_2 injection. Therefore the model must be closed or have little pressure communication with the surrounding hydraulic systems. A closed/semi-closed partially depleted gas reservoir based on the P18-A gas fields (near the coast of Rotterdam) from the SP5 database is chosen to carry out brine/water withdrawal simulations in this scenario (Figure 2).

According to Arts et al. (2012), natural gas production in the P18-4 field is projected to end just before the start of the CO_2 injection. The gas fields in block P18-A (P18-2, P18-4 and P18-6) are situated at approximately 3,500 m depth below sea level. The fields are located in a heavily faulted area and consist mainly of fault bounded compartments, which are (at least on production time scales) hydraulically isolated from their surroundings.

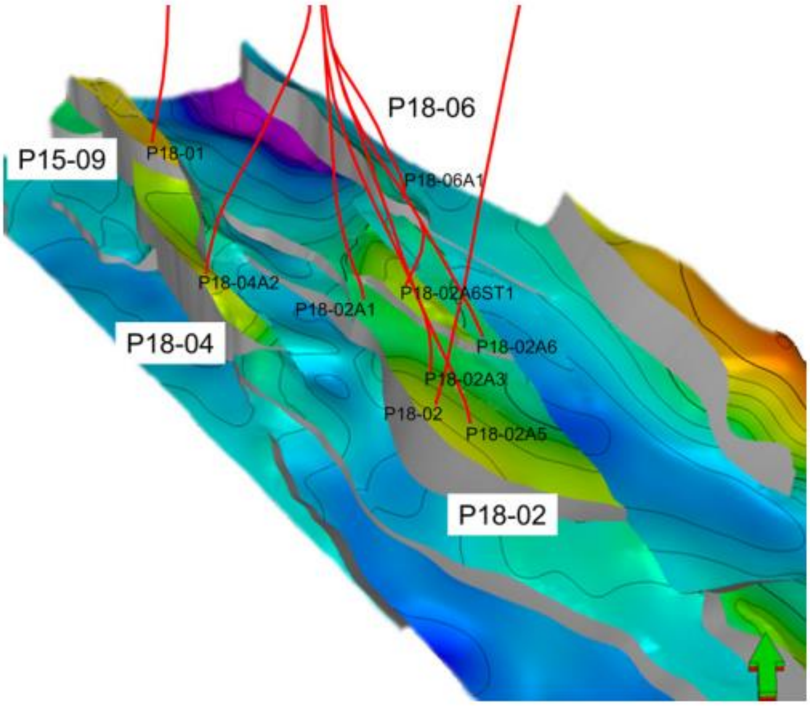
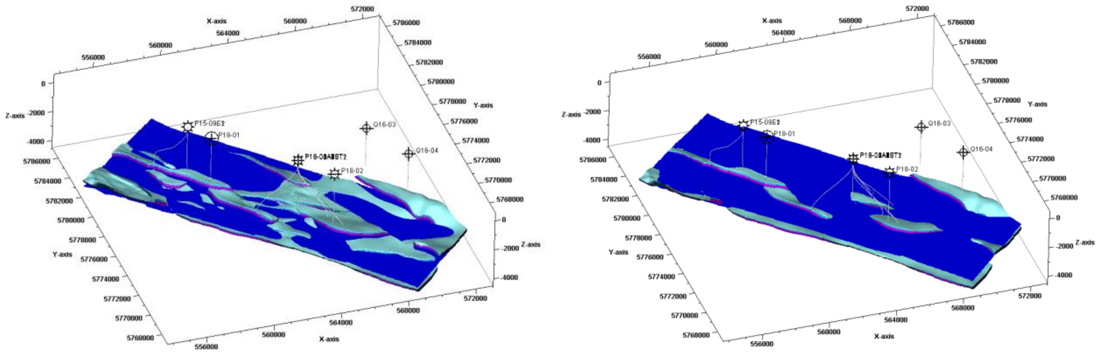


Figure 2: 3D view on the top of the P18 gas fields. Faults are shown in grey; well traces are shown in red (Arts et al., 2012).



(a) (b)

Figure 3: (a) the water-gas contact before gas production, (b) the water-gas contact after gas production.

Pre- and post-gas production gas–water contact (Figure 3) and pressure distribution can be quantified for this reservoir. The isolation of the reservoir could be confirmed by the different compositions of gas produced from P15-9 and P-18-4, and different gas–water contacts in P15-9 and P18-4. Arts et al. (2012) demonstrated that based on the history matched model, they could inject 8 Mt of CO_2 to build-up the original reservoir pressure up to 350 bar. However uncertainty exists for the data regarding the gas production history, the chosen abandonment pressure and the total amount of gas produced. Therefore it is assumed the CO_2 is injected with a rate higher than permissible rate and as a consequence the pressure has exceedingly built-up for the reservoir.

Different strategies of brine production will be utilised to investigate:

- the brine extraction rates required;
- the number of brine extraction wells required;
- the interval of brine extraction required;
- the response time required to relieve the excessive pressure build-up

3.3 Numerical Modelling of a saline deep aquifer

Subject of investigation is a real saline aquifer, which cannot be specified at this stage of work due to non-disclosure agreements. This aquifer was once considered and evaluated as a potential storage site. Even after a thorough feasibility study, several uncertainties concerning the safety of storage in this compartment remained. Like the P18 field, this aquifer is located in a highly faulted area. The seal of this compartment is also unproven. The total projected injection of CO_2 injection in this compartment was around 50 Mt. The fastest method to reduce the overpressure, once a problem occurs, is venting of the CO_2 although hysteresis and well effects might reduce the venting velocity. Both are subject of research in WP4.

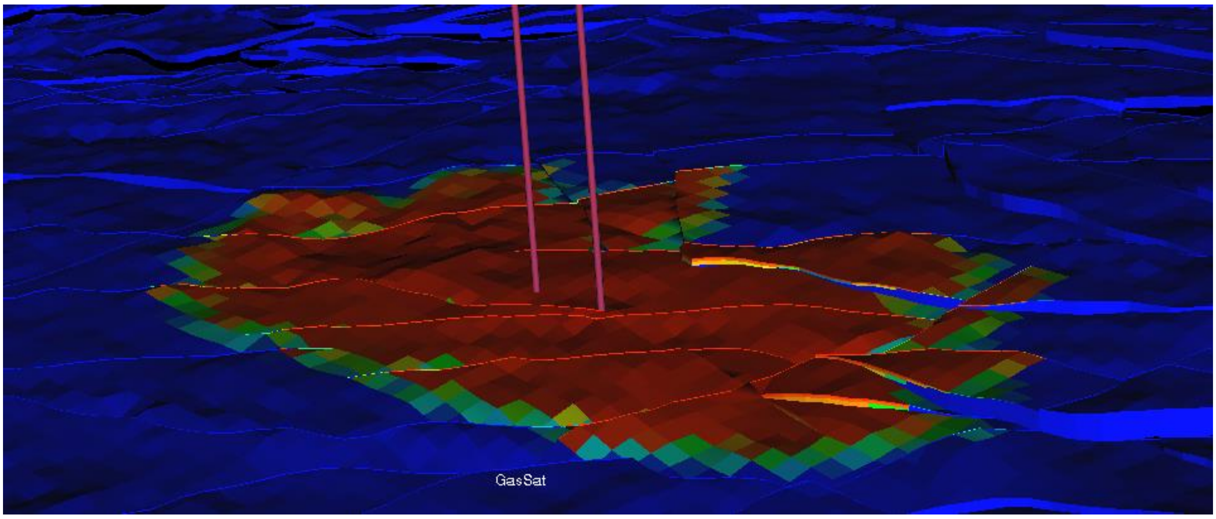


Figure 4: CO_2 saturation profile at the end of the injection.

4. INDIVIDUAL PROCESSES RELATED TO PRESSURE MANAGEMENT

4.1 Hysteresis and CO_2 storage

Relative permeabilities are essential concepts participating to the classical formulation of multiphase flow in porous media. For some time, experimental evidence and analysis of pore-scale physics demonstrate conclusively that relative permeabilities are not single functions of fluid saturations, displaying strong hysteresis effects. In the following subchapter, the relevance of relative permeability hysteresis is evaluated for modeling the geological CO2 sequestration process, with a strong focus on saline aquifer reservoirs. Many authors have presented simulations of CO_2 injection and migration (Ennis-King and Paterson, 2002; Wellmann et al., 2003; Xu et al., 2003; Flett et al., 2004; Kumar et al., 2005; Obi and Blunt, 2006) using a variety of approaches. Because of the density difference between CO_2 and brine, the low-viscous CO_2 tends to migrate to the top of the geologic structure. This upward migration is sometimes delayed or suppressed by low permeability layers that impede the vertical flow of CO_2. Several trapping mechanisms are recognized as affecting the stored CO_2, these being:

- Hydrodynamic trapping; the buoyant CO_2 is mobile, blocked by an impermeable cap rock.
- Solution trapping; dissolution of the CO_2 in the brine (Pruess and Garcia, 2002), possibly enhanced by gravity instabilities due to the larger density of the brine–CO_2 liquid mixture (Riaz et al., 2006)
- Mineral trapping; geochemical binding to the rock due to mineral precipitation (Pruess et al., 2003)
- Capillary trapping, disconnection of the CO_2 phase into an immobile (trapped) fraction (Flett et al., 2004; Kumar et al., 2005)

During the injection period, the less wetting CO_2 displaces the more wetting brine in a drainage-like process. However, after injection, the buoyant CO_2 migrates laterally and upward, and water displaces CO_2 at the trailing edge of the plume in an imbibition-like process. This leads to disconnection of the once-continuous plume into blobs and ganglia, which are effectively immobile. The importance of the ‘‘residual’’ CO_2 saturation has been pointed out in Hovorka et al. (2004), referenced to laboratory and field data from the Frio brine pilot experiment. However, no distinction was made between critical saturation (during drainage) and residual saturation (during imbibition) in their simulations. A study of CO_2 storage in saline aquifers that accounted for dissolution and chemical reaction (Kumar et al., 2005) considered relative permeability hysteresis using a Land-type model (see next subchapter). They concluded that the majority of CO_2 is stored as residual phase and, therefore, the more dominant mechanism than solubility or mineral trapping.

4.1.1 Pore-scale study

Hysteresis refers to irreversibility or path dependence in multiphase flow, and it manifests itself through the dependence of the relative permeabilities and capillary pressures on the saturation path and the saturation history. From the point of view of pore-scale processes, hysteresis has at least two sources. The first one is the contact angle hysteresis: the advancing contact angle (of wetting phase displacing a non-wetting phase) is larger than the receding contact angle (of wetting phase retreating by non-wetting phase invasion) due to chemical heterogeneities or surface roughness. The second source is trapping of the non-wetting phase: during an imbibition process, a fraction of the non-wetting phase gets disconnected in the form of blobs or ganglia, becoming effectively immobile (trapped). Hysteresis effects are larger in processes with strong flow reversals. This is the case of cyclic water and gas injection in a porous medium, in which the gas phase is trapped during water injection after a gas flood. A detailed explanation of trapping and hysteresis at the pore scale can be found in Lenormand et al. (1983).

Hysteresis Models

The most important quantity determining the significance of hysteresis effects is the trapped gas saturation after a flow reversal (from drainage to imbibition). A trapping model attempts to relate the trapped (residual) gas saturation to the maximum gas saturation, that is, the actual gas saturation at flow reversal. Most relative permeability hysteresis models make use of the trapping model proposed in Killough (1976). In this model, the trapped gas saturation S_{gt} is computed as:

$$S_{gt} = \frac{S_{gi}}{1 + CS_{gi}}$$

where: S_{gi} = Initial gas saturation (gas saturation at flow reversal)
C = Land trapping coefficient

The Land trapping coefficient is computed from the bounding drainage and imbibition relative permeability curves as follows:

$$C = \frac{1}{S_{gt,\max}} - \frac{1}{S_{g,\max}}$$

where: $S_{g,max}$ = maximum gas saturation
$S_{gt,max}$ = maximum trapped saturation, associated with the bounding imbibition curve.

All these quantities are illustrated in Figure 5. The Land trapping model has been validated by comparison with experiments in Killough (1976). The bounding drainage and imbibition curves from the experimental data of Figure 5 result in a Land trapping coefficient C ~ 1.

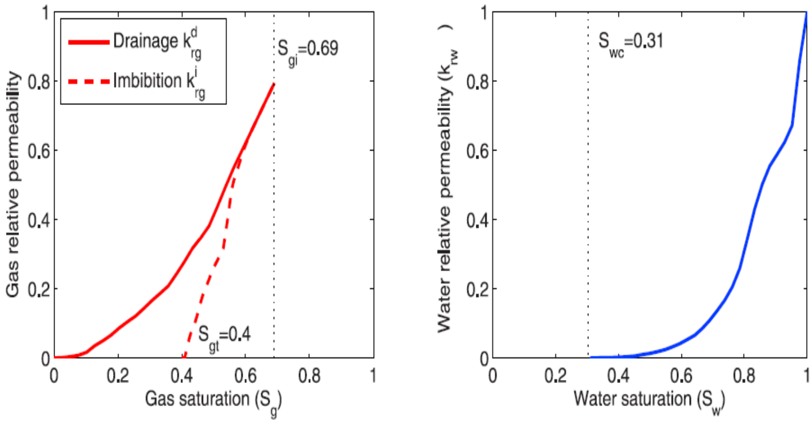


Figure 5: Relative permeability (water-wet Berea sandstone).

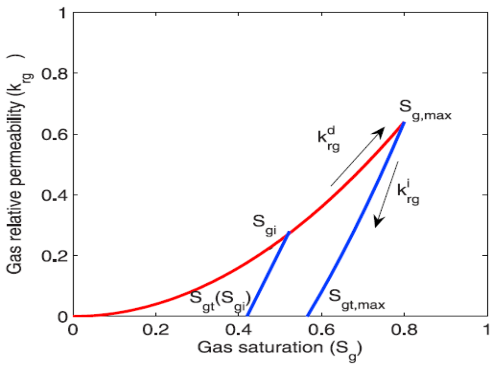


Figure 6: Parameters of Land model.

Another popular relative permeability (Kr) model is the Killough model (Killough, 1976). In Killough's method, the gas relative permeability along a scanning curve, such as the one depicted in Figure 6, is computed as:

$$K_{rg}^{i}\left(S_g\right) = K_{rg}^{ib}\left(S_g^{*}\right)\frac{K_{rg}^{d}\left(S_{gi}\right)}{K_{rg}^{d}\left(S_{gi,\max}\right)}$$

$$S_g^{*} = S_{gt,\max} + \frac{\left(S_g - S_{gt}\right)\left(S_{gi,\max} - S_{gt,\max}\right)}{S_{gi} - S_{gt}}$$

In the above equations, K_{rg}^{d} and K_{rg}^{ib} represent the bounding drainage and imbibition curves, respectively. The bounding imbibition curve is assumed to be available from experiments, or computed using Land's imbibition model. In Killough's model, scanning curves are assumed to be ''reversible'', so that the imbibition curve is representative of a subsequent drainage process. Capillary pressure–saturation relationships also exhibit marked hysteresis effects. Several mathematical models exist to treat hysteretic capillary pressure curves, including the one proposed by Killough. From a practical point of view, however, capillary pressure effects are often negligible at the time of numerically simulating field-scale displacements, when the characteristic capillary length is much smaller than the grid resolution (Aziz and Settari, 1979).

The above mentioned state of the art implies that laboratory data are available. Efforts have been made to obtain the maximum gas saturation values from correlation to other standard petrophysical properties (Keelan and Pugh, 1975; Batycky et al., 1988; Hamon et al., 2001; Holtz and Major, 2002). Maximum residual gas saturation (S_{grm}) is what initially results from imbibition on rock at irreducible water saturation (S_{wirr}). S_{grm} results from gas acting as the non-wetting phase during imbibition hysteresis as pressure is depleted in a gas reservoir and an aquifer encroaches in pore space that was once filled with gas. Numerous influences may affect S_{grm}: (1) how the wetting fluid gets in (either forced or spontaneous imbibition), (2) type of wetting fluid, (3) rate of imbibition, (4) rock type (lithology, grain size and sorting), (5) pore type, (6) wettability and (7) interfacial tensions.
Porosity has been shown to have the strongest relationship to S_{grm}. Nearly all studies involving a porosity-S_{grm} relationship indicate that S_{grm}, increases as porosity decreases (Keelan and Pugh, 1975; Jerauld, 1996; McKay, 1974; Delclaud, 1991). With water acting as the wetting phase and gas acting as the non-wetting phase, S_{grm} results from pore scale capillary forces. S_{grm} is the trapped non-wetting phase when the wetting phase has been imbibed into the rock from a state of irreducible water saturation to a state of zero capillary pressure. The models that describe how this trapping occurs are pore-geometry dependent. Three trapping models are possible (Figure 7). The pore doublet model is more likely to occur in poorly sorted rock or in rock with dual-porosity networks. The pore snap-off and dead-end models are more likely to occur in lower porosity rocks.

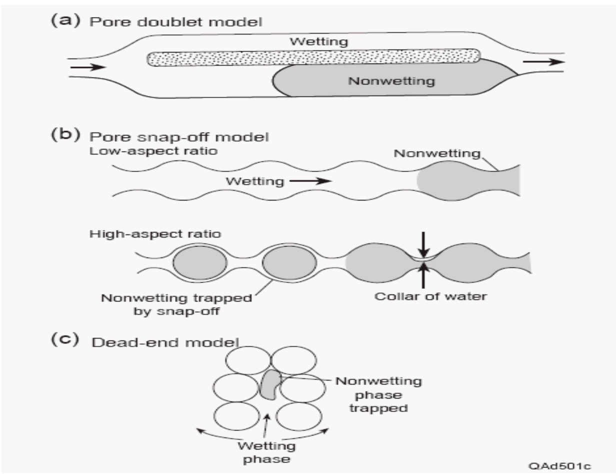


Figure 7: Three conceptual trapping models.

Different S_{gr}-PHI relationships are shown in Figure 8.

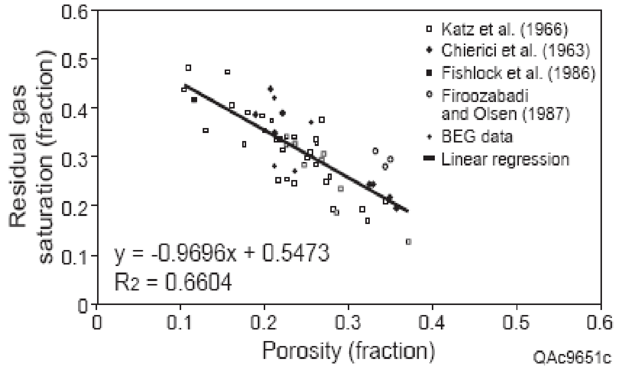


Figure 8: Different experimental data relating porosity to residual gas saturation.

Thus, one can use for S_{grm} the correlation above or make use more generally of a relationship which conciliates petrophysical properties such as permeability (K), irreducible water saturation (S_{wirr}) and S_{grm}. They must be integrated in such a way that S_{grm} is a function of S_{wirr} so that the initial condition of S_{grm} being less than or equal to the initial gas saturation is met. This initial condition is met with the development of an initial residual non-wetting phase curve (IR curve). The general shapes of IR curves are shown in Figure 9 (modified from Lake, 1996). These curves represent the character of an individual rock sample. The end point to the curve is the S_{grm} value. The shape of the initial-residual wetting phase saturation curves displays the effect of rock type. As sandstone becomes cleaner, better sorted, and less cemented (higher porosity), the curves move farther away from the 1 to 1 line, increasing in slope as S_{grm} decreases.

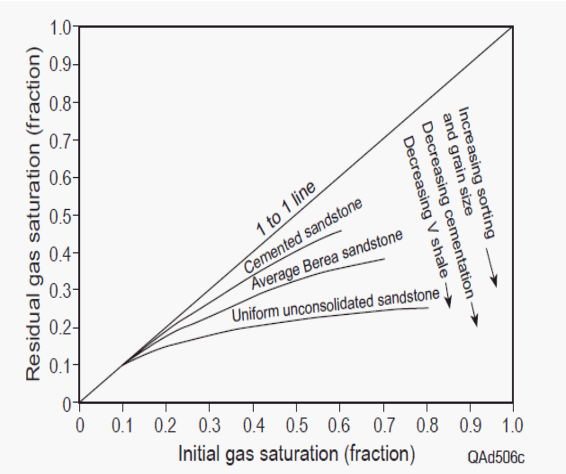


Figure 9: IR curves.

The curves must stay below the 1 to 1 line, terminate at a given S_{grm}-S_{gi} position, and decrease in slope with higher quality rock. The modified Land's equation below meets these criteria:

$$S_{gr} = \frac{1}{\left[\left(\frac{1}{S_{grm}} - 1\right) + \left(\frac{1 - S_{wirr}}{Sg}\right)\right]}$$

Thus, given a set of S_{wirr}-S_{grm} values, the S_{gr} can be determined for a given $S_{g.}$ It is to be noted that a relationship between residual gas saturation and porosity is given with data obtained from the Frio pilot project (Figure 10).

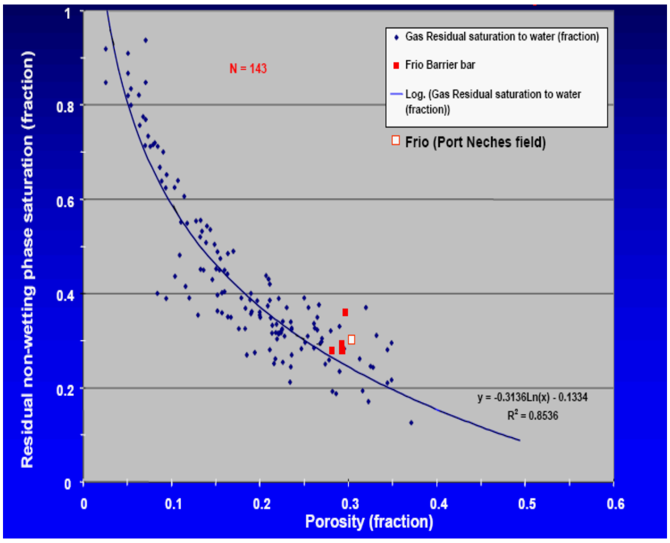


Figure 10: Residual gas saturation vs porosity (Holtz, 2005).

4.1.2 Reservoir-scale study

During injection of CO_2 in a storage compartment, the ambient fluids in the reservoir are displaced. In the case of P18-4, the injected CO_2 enters the available pore-space involving displacement and mixing processes with the remaining natural gas molecules. In this situation the water phase is not or hardly displaced. During the event of venting, the re-production should therefore not be subject to hysteresis. In the case of an aquifer, the CO_2 is injected in a pore-space, which is already occupied by the brine phase. This means that the wetting fluid is displaced (so-called drainage process). Reversal of the flow during the event of venting would result in hysteresis and relative permeability-saturation curves, which are a function of the displacement history (reversal points, entrapment etc.). Several models have been derived for describing hysteretic relationships. Examples are Lenhard and Parker (1987), Parker and Lenhard (1987). Oak (1990), however, mentions that many data sets are at best limited to just a couple of saturation history cases. Besides during venting, reversal of displacement also occurs when brine re-imbibes into areas, vacated by the CO_2 during redistribution within the aquifer. The entrapment, associated with hysteresis, also increases the interfacial area between the CO_2 and the brine. This leads to more rapid dissolution and thus to more rapid pressure reduction.

The starting point was a non-hysteretic reservoir model, which was one of the deliverables of the aforementioned feasibility study. The relative permeability-saturation curves for the carbon dioxide were made hysteretic, while those of the wetting fluid (brine) were left non-hysteretic. With this model, a number of simulations were carried out. Back production of CO_2 as predicted by the reservoir model with and without a hysteretic description was compared. A limited sensitivity analysis was carried out for various bottom-hole pressures, periods between the end of injection and the actual reproduction etc.

Future investigation would involve: 1) The impact of hysteresis on the long term extent of the migration, 2) massive water injection to immobilize (by entrapment) and pushing the CO_2 away from a possible faulty well.

4.2 Well effects during back production

The back production of CO_2 reverses the flow direction and multiphase flow phenomena occur that are fundamentally different as those from the injection. During injection only one operational state exists, changing the injection rate induces gradual differences in the injection pressure. In contrast, the back production phase can be described by three different operational modes. At small production rates $r_{CO2} < r_{c1}$ pure CO_2 can be produced continuously at wellhead elevation (Figure 11a). However, at reservoir elevation both, CO_2 and brine are extracted from the sandstone. The water has a higher density than CO_2 and remains in the lower part of the well where it reinfiltrates into the formation. Therefore a water cone develops (Figure 11a-c).

With increasing rates more water is produced and the reinfiltration capacity of the formation is exceeded. This occurs when the critical rate r_{c1} is exceeded. This rate depends on the CO_2 saturation, distribution and reservoir petrophysical properties. The water level rises above the well filter and the CO_2 passes through the water column in the form of bubbles (Figure 11b). The water column has a higher density than the CO_2 column and therefore, the bottom-hole pressure is reduced. Depending on the control mode at the outlet and the reservoir behavior, the water column may rise such that the CO_2 flux decreases below the nominal rate.

In case the rate of CO_2 exceeds the Turner velocity ($r_{CO2} > v_{Tur}$) the brine is dispersed and entrained by the CO_2, transported upwards and arrives at the wellhead. No accumulation occurs (Figure 11c).

For the Ketzin case, production rates will be between 800 and 3200 kg/h. The magnitude of the critical rate r_{c1} is not known prior to the test. The critical rate r_{Tur} is about 2700 to 3800 kg/h (Bannach et al., 2014), depending on the test conditions.

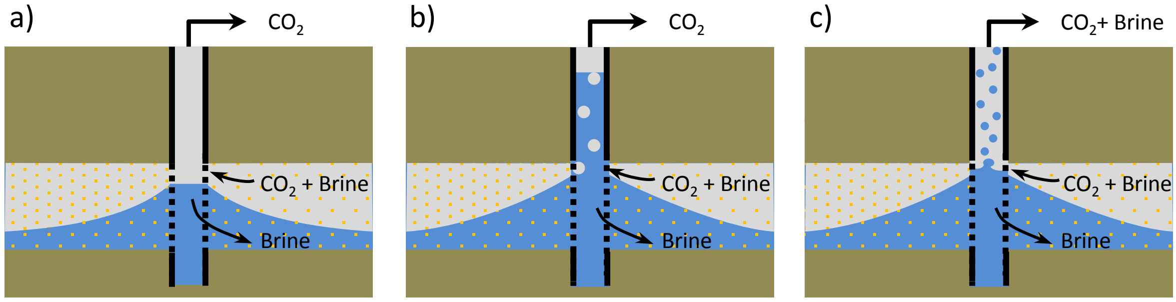


Figure 11: Three operational modes during the back production test.

4.3 Application of nanoparticles

The application of nanoparticles may improve the performance of CO_2 injection and storage and has potential as a remediation method in the case of leakage. Nanoparticles can potentially increase the dissolution of CO_2 and promote the formation of emulsions and foams with the reservoir brine. The main benefits are:

1. Reduction of the pressure
2. Decrease the amount of undissolved CO_2 that can potentially leak: dissolved CO_2 is trapped. An additional benefit is the fact that the density of the brine increases due to the dissolution of CO_2, which makes it less buoyant or even negatively buoyant.

The primary application of nanoparticles that is considered is the remediation of leakage scenarios with comparatively low rates. This is based in the comparatively slow reaction rates in comparison to hydraulic processes.
Task 4.5 addresses enhanced CO_2 dissolution by application of nanoparticles to enhance the process of convective mixing.
Nanoparticles (solid particles in the size range $< \mu m$) can be used to stabilize emulsions by interfacial adsorption to form so-called solid-stabilized or Pickering emulsions. The adsorbed particle layer provides a steric barrier that prevents the coalescence of emulsion droplets. The driving force for interfacial adsorption is the reduction of the interfacial area of the two phases (in our case CO_2 and brine) and a corresponding reduction in the interfacial energy. Molecular surfactants can also be used for the stabilization of emulsions, but the working principle is different. Molecular surfactants stabilize emulsions by reducing the interfacial tension and not so much the interfacial area. In general it can be stated that Pickering emulsions are more stable against coalescence as otherwise stabilized emulsions. To achieve Pickering stabilization, the nanoparticles should have an intermediate wettability with respect to CO_2 and brine. Potential particles might be silica, clay (Planomer® technology), cellulose fibers (Greenanofilm, EU FP7), soot, and carbon black. All particles can be coated (engineered nanoparticles as e.g. Aminzadeh et al., 2013). The major advantage of Pickering stabilization is the stability under the extreme conditions underground (high pressure, temperature, salinity etc.) and the possibility to increase density by selecting nanoparticles with high density.

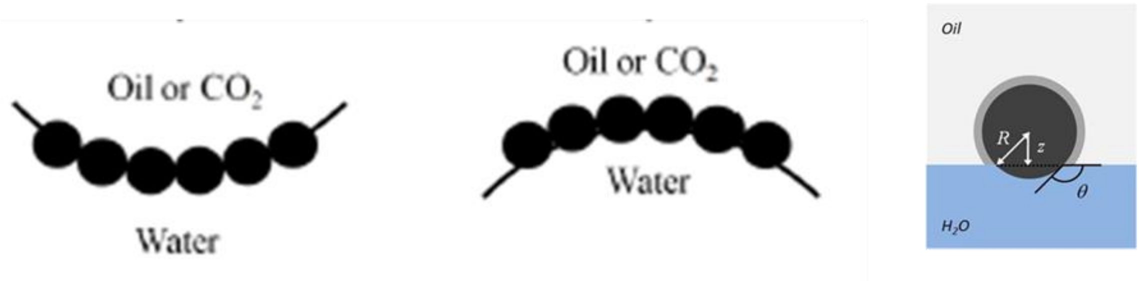


Figure 12: Interfacial adsorption of emulsion by solid nanoparticles.

Most literature on CO_2 and nanoparticles discusses the creation of stable emulsions or foams of CO_2 and brine for different purposes: for CO_2 storage in aquifers (Espinosa et al., 2010; Hariz, 2012; Aminzadeh et al., 2013), for CO_2 storage in deep ocean environments (Golomb et al., 2006; Golomb et al., 2007), or for enhanced oil recovery using CO_2 (e.g. Jikich, 2012; Worthen et al., 2012; Al-Otaibi et al., 2014). The goal of the stable foams or emulsions is always to decrease the mobility of the CO_2, because the mobility of the foam is lower than that of the individual pure phases (DiCarlo et al., 2011). Nanoparticles can be used in three different ways:

1. Increase CO_2 dissolution by enhancing convective mixing.

Convective mixing is a process that occurs in CO_2 underlain by brine (Green and Ennis-King, 2013; Huppert and Neufeld, 2014; Szulczewski et al., 2013). The CO_2 dissolves in the underlying brine via diffusion, which increases the density of the brine and creates an inherently unstable, high density boundary layer. At some point, downward flow will start via fingering, which replaces the saturated brine in the boundary layer with fresh, unsaturated brine. This process significantly enhances the dissolution of CO_2. The nanoparticles could be used to enhance the onset and efficiency of the convective mixing (Javadpour and Nicot, 2011; Singh et al., 2012). The two questions addressed are to determine the injection method and the type of applicable particles.

2. Increase CO_2 dissolution during CO_2 injection and the subsequent convection of the CO_2 plume.

The application of a disperser during CO_2-injection can reduce droplet size and increase the dissolution of CO_2. Reduction of the droplet size could also be achieved by pumping the CO_2 through the porous formation itself. Upon passing through the pores, the super critical CO_2 deforms, increases the interfacial area with brine and allows particle adsorption. The created interfacial area is then stabilized against coalescence. This might have the unwanted side-effect that the smaller CO_2 droplets can pass more easily through pore throats and become more mobile because of that. The question is really how small the droplets will become during injection. The amount of brine present in the vicinity of the well is not sufficient to store the CO_2. The accumulation of CO_2 is the limiting factor, rather than the speed of dissolution of CO_2. This means that CO_2 needs to be mixed with water/brine and disperser in the well. Consequently, research needs to consider that large amounts of water or brine are required. If it becomes apparent that the use of nanoparticles is not suitable as a remediation method, it will not be further investigated in this task.

3. For immediate remediation in case of high-rate leakage through a fault or along a spill point

Nanoparticles could be injected close to the area of leakage with the goal of reducing the mobility of the CO_2 by creating foams and/or emulsions and possibly immobilizing the leaking CO_2 by increasing the dissolution. Main questions are how much the mobility of the CO_2 can be reduced and whether the dissolution can be accelerated sufficiently and whether there is sufficient storage capacity. Also it should be studied how the nanoparticles can be transported to the required location, for example via hydraulic fractures. This scenario and the associated research questions are addressed in Tasks 6.3 and 6.4.

5. INDUSTRY PRACTICE

Flow diversion methods (control of the plume position) are currently applied for oil fields, since these frequently comprise a high number of wells. The operational mode is changed on the breakthrough of gas or water to production wells. There is no knowledge about predictive modelling here. Gas fields in contrast typically have a lower number of wells and typically not a defined breakthrough, wherefore flow diversion is not applicable. Direct CO_2 injection for enhanced gas recovery is not carried out since the natural gas would be contaminated and require subsequent separation. Natural gas storage is carried out in formations with a natural boundary, which may be a close boundary in case of reservoir compartments or an open boundary in case of anticline structures. These boundaries control the plume shape, wherefore active plume management is not carried out.

The plume migration direction is considered the dominating risk at the In Salah test site for CO_2 injection (Dodds et al., 2011). Furthermore, a spill point is another significant risk, wherefore the corresponding plume distance is regularly monitored and the injection was interrupted when spill point was approached.

Traditionally the reservoir pressure is observed top-hole. In the mid 90's the first bottom-hole equipments have been installed in North Sea fields, and in the US this instrumentation spreads out with the beginning of the 2000 years. There is actually a lot of technical progress in this field of application and bottom-hole gauges are almost standard now. Frequently they are based on fiber optics with distributed temperature and pressure management and the possibility to connect additional sensor types. However, the devices can be easily damaged during installation, which was the case at the Cranfield (Mississippi, USA) and In Salah (Algeria) site. At the Ketzin site bottom-hole pressure is observed with a Weatherford optical sensor. Similar pressure and temperature sensors have been installed at the Aquistore test site (Canada). It has to be considered, that bottom-hole pressure frequently means that the sensor is close to the reservoir, but some distance above the reservoir elevation. At the Ketzin test site, the sensor is located at 550m, about 90 m above the reservoir.

The primary control variable for natural gas storage is the maximum pressure. The maximum limit is the allowable pressure to stay well below fracture pressure, but the maximum operational pressure of the compressor type may also be a practical limit. Currently there are no cases known where a remediation of a natural gas storage became necessary.

Heuristic analytical models based on Darcie's Law are used as straightforward solution for vertical wells with either closed or open boundaries. Since horizontal wells became standard and numerical methods improved, most of them are not applicable any more. Numerical models are used instead and are nowadays standard method for reservoir management. A prognosis typically predicts an interval of 3-6 months. There are three big families for reservoir models, they are the Eclipse family from Schlumberger, the Stars system from CMG and Quiklook reservoir simulator from Halliburton.

There is no commercial application of nanoparticles yet.

Suggestions:

- Microgravity is rapidly evolving for reservoir monitoring with the focus to offshore applications. It should be considered to include this in MiReCOL.
- Tracers are important to distinguish injected from natural CO_2 to improve leakage detection. An alternative to SF_6 would be desirable. Some research on this is carried out art Snovit, in Edinburgh research on nitrogen and helium is carried out.

The Interview was based on the following questions

- Are there standard procedures in which flow diversion methods are applied?
- In which cases is the plume shape explicitly considered?
- How is the reservoir pressure observed? Top- or bottom-hole? Which are the most common gauges applied in industrial fields?
- Are there differences for application in
  - natural gas fields?
  - underground gas reservoirs?
  - oil fields?
  - others (e.g. salt caverns)
- Most relevant to MiReCOL are gas reservoirs which comprise an aquifer.
  - Which are the control variables? Which are the parameters to be optimized?
  - Which analytical approximations are applied?
  - Which numerical models are applied for predicting pressure and the effect of management methods?
  - What kind of remedial activities do you consider, when a spill point in natural gas storage may/is reached. How do you monitor that?
  - Under what situation would you consider venting as a final remedial action?
- Nanoparticles
  - Are you aware of any use of substances like nanoparticles used for pressure management (rather than tertiary recovery)?
  - Do you know of any field-scale or test implementations of nanoparticles for CO_2-EOR?

6. SUMMARY

This report should summarize the state of the art of pressure management in petroleum industry practice. As an intensive literature study has shown, pressure management does not play an important role in industrial context of oil and gas production. For CO_2 storage reservoirs, however, pressure is a critical parameter because reservoirs are filled up overpressured and, as consequence, the caprock integrity might be compromised. The leakage from an overpressured reservoir has high potential for environmental pollution. Research is required to assess its potential for operation and remediation of CO_2 storage reservoirs. The present report outlines the state of the art and the planned workflow within the project topic “Pressure management”.

The natural reservoir features, such as type of reservoir, type of boundary conditions, hysteresis properties etc. have a dominating impact on reservoir behaviour and, therefore, on the pressure management. A careful assessment of these conditions is the prerequisite for the choice of an appropriate remediation method. It is crucial to reduce the number of potential remediation methods a priori, because the second step of numerical modelling requires much larger effort and only allow a limited number of simulations. Numerical modelling is necessary for quantification of the remediation efficiency, comparison of different remediation methods and optimization of the operational scheme. The models within this report are site specific but it is intended to derive generally valid best practice rules and to quantify the remediation success.

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