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Current flow diversion techniques in the petroleum industry relevant to CO_2 leakage remediation

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Public abstract

This part of the MiReCOL project sets out to investigate the possibilities for flow diversion and mobility control of an unwanted migration of CO_2 within the storage reservoir. Other elements will consider mitigation of leakage through the caprock, faults or fractures, and the control of unwanted migration beyond the reservoir seals.

More specifically, this work will investigate techniques for controlling CO_2 migration by means of the following techniques:- a revised injection strategy, injection of gel or foam to form a barrier, injection of water or brine, and injection of reactant chemicals which cause the CO_2 to precipitate as a solid.

This deliverable considers any current practices and theoretical techniques in the petroleum industry which are similar, or which might be applied to the CO_2 mitigation techniques to be investigated in this work.

Public introduction (*)
CO_2 capture and storage (CCS) has the potential to reduce significantly the carbon emission that follows from the use of fossil fuels in power production and industry. Integrated demo-scale projects are currently being developed to demonstrate the feasibility of CCS and the first such projects are expected to start operating in Europe under the Storage Directive in the period 2015 – 2020. For the license applications of these projects a corrective measures plan is mandatory, describing the measures to be taken in the unlikely event of CO_2 leakage. This project will support the creation of such corrective measures plans and help to build confidence in the safety of deep subsurface CO_2 storage, by laying out a toolbox of techniques available to mitigate and/or remediate undesired migration or leakage of CO_2. The project is particularly aimed at (new) operators and relevant authorities. One of the elements of the MiReCOL project is to investigate the possibilities for flow diversion and mobility control of an unwanted migration of CO_2 within the storage reservoir. This is distinguished from mitigation of leakage through the caprock and other seals, and the investigation of specific techniques for control of unwanted migration beyond the seals, which are the subjects of other elements of the MiReCOL project. The element of the MiReCOL project of which this is the first report, investigates various techniques for control of CO_2 migration including: i) injection strategy, ii) gel or foam injection, iii) water or brine injection and iv) injection of chemicals which react with CO_2 and precipitate it as a solid. As a first step, this report considers current practices in the petroleum industry which are similar, or which might be applied to the CO_2 mitigation techniques to be investigated in this work. Many concepts for flow diversion have been considered by industry, mainly for increasing the recovery of oil or gas, but several of these have remained theoretical and have not been widely applied in practice. Both applied and theoretical techniques are potentially interesting candidates for this investigation. The results of this work will contribute to later activities that will assess the effectiveness and consequences of all leakage mitigation measures, leading to the production of a Corrective Measures Handbook.

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1 INTRODUCTION

CO_2 capture and storage (CCS) has the potential to reduce significantly the carbon emission that follows from the use of fossil fuels in power production and industry. Integrated demo-scale projects are currently being developed to demonstrate the feasibility of CCS and the first such projects are expected to start operating in Europe under the Storage Directive in the period 2015 – 2020. For the license applications of these projects a corrective measures plan is mandatory, describing the measures to be taken in the unlikely event of CO_2 leakage. This project will support the creation of such corrective measures plans and help to build confidence in the safety of deep subsurface CO_2 storage, by laying out a toolbox of techniques available to mitigate and/or remediate undesired migration or leakage of CO_2. The project is particularly aimed at (new) operators and relevant authorities.

One of the main objectives of MiReCOL project is to investigate the possibilities for flow diversion and mobility control of an unwanted migration of CO_2 within the storage reservoir. This is distinguished from mitigation of leakage through the caprock and other seals, and the investigation of specific techniques for control of unwanted migration beyond the seals, which are the objectives of other elements of the MiReCOL project.

This report reviews current flow diversion techniques in the petroleum industry which are similar, or which might be applied to mitigating against non-conformal behaviour of CO_2 within the storage reservoir. These include: i) injection strategy, ii) gel or foam injection, iii) water or brine injection and iv) injection of chemicals which react with CO_2 and precipitate it as a solid. The first of these techniques is only introduced briefly since it is covered in detail in Deliverable D4.1 "Report on current reservoir pressure management measures in the petroleum industry".

Many concepts for flow diversion have been considered by industry, mainly for increasing the recovery of oil or gas, but several of these have remained theoretical and have not been widely applied in practice. Both applied and theoretical techniques are potentially interesting candidates for this investigation.

The results of this work will contribute to later activities in the project, which will assess the effectiveness and consequences of all measures taken against non-conformal behaviour, leading to the production of a Corrective Measures Handbook.

2 BACKGROUND AND REVIEW OF THE VARIOUS FLOW DIVERSION TECHNIQUES CONSIDERED

2.1 Injection strategies

The position of a CO_2 plume is crucial in determining the leakage risk. It is desired to keep the plume away from geologically weak zones, such as faults, spill points, old abandoned wells or weak regions of the cap rock. Therefore, MiReCOL will investigate whether possibilities exist to affect the plume's position by reservoir management methods.

In the hydrocarbons industry context, the concept of plume control is mainly applied to oil fields, where the presence of numerous wells allows a comparatively accurate spatial determination and allows the choice of optimal production and injection from/into wells as a control device. In CO_2 storage the number of wells may be limited primarily due to cost, but also due to the wish to minimise the number of potential leakage sites. Therefore, new strategies for CO_2 flow diversion shall be investigated within this part of MiReCOL.

Flow diversion and pressure management are physically closely connected to the same processes in the reservoir. During injection and plume expansion water is replaced by CO_2 and the resulting pressure gradient is a direct consequence of this replacement. Despite the fact that the same physical process underlies both phenomena, the position and shape of the plume are much more difficult to predict or monitor compared with pressure. The pressure is rather similar at different reservoir positions, regardless of whether CO_2 or brine is present, but multiphase flow phenomena such as fingering, channelling and hysteresis allow many different saturation states for the same reservoir pressure (Lu and Lichtner, 2007, Wang et al., 2013). Heterogeneities can significantly alter flowrate and the flow field, while the pressure may be less affected. Furthermore, pressure is typically monitored at a limited number of wells, while the spatial distribution of a CO_2 plume contains many more degrees of freedom and can be determined by seismic or geoelectrical methods.

These techniques are covered in detail in Deliverable D4.1 "Report on current reservoir pressure management measures in the petroleum industry".

2.2 Gel and foam injection

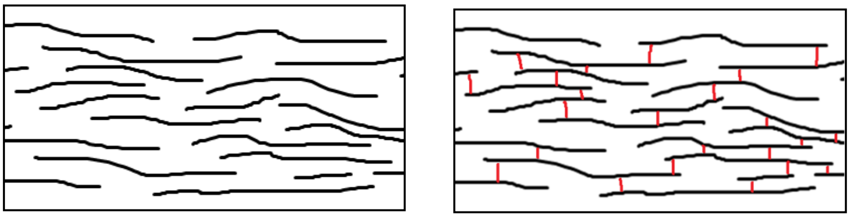
2.2.1 Gel injection

Cross-linked hydrolysed polymer-gel injection is used in petroleum industry to improve conformity of fluid flow in the reservoir, remediate leakage around wells and also used in conjunction with the prospect of enhanced oil recovery under various temperature and pressure conditions (Sydansk, 1988; Hunter et al., 1992; Gao et al., 1993; Whitney et al., 1996; Hutchins et al., 1996; Bryant et al., 1996; Kantzas et al., 1999; Ricks and Portwood, 2000; Sydansk and Southwell, 2000; Wouterlood et al., 2002; Herbas et al., 2004; Sydansk et al., 2004; Sydansk et al., 2005; Norman et al., 2006; Zhao et al., 2006;

Turner and Zahner, 2009; Al-Muntasheri et al., 2010) and to improve miscible CO_2 floods (Hild and Wackowski, 1999; Saez et al., 2012).

The majority of field practice in applying gel treatments aimed to reduce channelling in high-pressure gas floods and to reduce water production from gas wells (Seright, 1995; Raje et al., 1999; Grattoni et al., 2001; Sydansk and Seright, 2007). Often referred to as relative permeability modification (RPM) or disproportionate permeability reduction (DPR) and water shut off (WSO) treatments, there are many examples of production performance modelling data for gel treated wells in the literature (Wassmuth et al., 2004; Herbas et al., 2004). In the early days of the technology, RPM treatment was mainly used in controlling flow in matrix-rock porous media. More recent research have reported successful treatment of fractured rock where relatively strong gels impart RPM/DPR to fluid flow within gel filled fractures and achieve total shutoff (Sydansk et al., 2005).

Hydrolysed polyacrylamide (*Figure 1a*), in various proportions, is one of the widely used polymers within the petroleum industry (Flew and Sellin, 1993; Rodriguez et al., 1993). The polymer exists as loose molecular chains in the aqueous solution. When appropriate cross-linker is added, these polymer chains are aligned and this polymer solution is turned into a solid gel which resembles the structure illustrated in *Figure 1b*. Metal ions such as Cr^{3+} (Prud'homme and Uhl, 1984; Sydansk, 1990; Albonico and Lockhart, 1993; Lu et al., 2010) and Aluminium (Dovan, 1987; Smith, 1995) have been used as a crosslinkers, although occasional use of organic cross-linkers such as formaldehyde (Albonico et al., 1995) was also observed. Polyacrylamide based-gel solutions are used in the industry to selectively shut off undesired gas influx in production fields (Sanders et al., 1994; Sydansk et al., 2004; Simjoo et al., 2009; Reddy et al., 2012) and sometimes in combination with other surfactants (Woo et al., 1999). Application of polyacrylamide-gel solution for modifying injectant flow profile are also noted (Chan, 1989) in addition to remediating non-conformal flow within the reservoir (Mebratu et al., 2004).



(a) (b)

Figure 1. *Artistic representation of polymer chains in carrier fluid and (b) effect of cross-linker on the arrangement of polymer molecules in the solution.*

The rheological characteristics of polymers injected into the subsurface reservoir are modified in time either by adding an additive, or just by interaction with the environment such as variation in temperature, pressure or surrounding fluids. These changes are observed to be accomplished either through the injection of individual components i.e., monomer, cross-linker and other additives or through injection of cross-linked polymer directly into the reservoir (Hubbard et al., 1988).

The time taken for hydrolysed polymer to be converted into polymer gel upon the addition of cross linker is generally termed as gelation time, which is also an indicator of the possible penetration of the injected polymer gel solution into the reservoir before it solidifies. Gelation time is also defined as the time when the elastic and viscous moduli of the gel are equal (Tung and Dynes, 1982). This time is dependent on the characteristics such as chemical composition, molecular weight and concentration of the polymer, temperature and cross-linker type. Hence, the temperature and salinity of the reservoir are important factors in the selection of appropriate concentration of a polymer and the cross-linker. Addition of organic ligands and pre formed Cr^{3+} complexes with suitable ligands added to the polymer solution were found to control the gelation time over the temperature range of 60-135°C (Albonico et al., 1993). Furthermore, aqueous solution of dilute polyacrylamide was reported to be reasonably stable under shear (Bruce and Schwarz, 1969). The stability of a polymer-gel system was reported to be dependent on the stability of polymer molecules themselves (Albonico and Lockhart, 1993; Moradi-Araghi et al., 1993).

Preliminary laboratory characterisation and assessment for field application of one polyacrylamide based polymer gel system was carried out as part of the EU funded CO_2CARE project. The important conclusions of the work are summarised here:

1. The gelation time decreases with increase in polyacrylamide concentration; furthermore, for identical combination of polyacrylamide and a cross-linker, the gelation time was found to decrease with increase in temperature.
2. CO_2 permeability reduction of more than 99% can be achieved in high permeability sandstones
3. It was found that an increase in brine salinity generally leads to the destruction of the polymer chains and a notable reduction in effectiveness of the gel. However, almost 90% reduction in permeability was still achieved in higher salinity (12 to 25%) environments.
4. Water slug injection experiments in the laboratory have confirmed that the negative impact of high salinity can be reduced by this technique.
5. In summary, high molecular weight, anionic and hydrolysed polymer chains such as polyacrylamide along with cross-linker such as Cr^{+3} can be used to remediate leakage of CO_2 if the area of influence is carefully evaluated and the injection process designed accordingly.

The design of an efficient remediation strategy using polymer gel for possible CO_2 leakage would depend on engineering the gelation time of the polymer and cross-linker combination for the targeted subsurface reservoir conditions, which would be investigated though the current research.

2.2.2 Foam injection

Foams have been used in EOR as a very promising and cost effective means to alleviate the drawbacks associated with gas-based processes leading to early gas breakthrough. Foams can be used for in-depth gas mobility control, as blocking agents in thief zones and for conformance control in fractures or layered reservoirs. Thus, besides their use for EOR purposes, they can be also used to secure gas storage operations through gas confinement and gas leakage remediation.

A foam system consists of a continuous water phase with dispersed gas bubbles at a given volumetric fraction. Gas bubble formation requires a certain amount of energy provided by shear, and is stabilized by surfactant foaming agents dissolved in the water phase, or the gas phase in the case of CO_2.

Among the properties of foams, stability is of most importance. Foams are dispersed systems and as such they are intrinsically unstable with time. However for gas mobility control in EOR, foam should be stable and propagate within the reservoir, while for conformance and blocking purposes they should remain stable in place for a given time to ensure the economic viability of the process.

For CO_2, the mobility reduction factor is usually much lower than with hydrocarbon gas and the maximum attainable effect decreases rapidly with CO_2 density (Chabert et al., 2012; Solbakken et al., 2013). With supercritical CO_2 it was inferred from a laboratory study using a classical foaming agent that probably only coarse foam-emulsions could be formed. However, more recent results have shown that using dedicated surfactant formulations, high gas mobility reduction factors could be obtained, even with dense-phase CO_2, indicating the formation of strong foams (Chabert et al., 2014).

Currently, large uncertainties still remain regarding the actual physics underlying foam flow in porous media. Though previous studies have not proposed a satisfactory physical model for foam flow and propagation, they have generated a general, though useful, phenomenological description of the rheological behaviour of foams in porous media (Gauglitz et al., 2002; Skauge et al., 2002; Tanzil et al., 2002; Farajzadeh et al., 2009; Enick et al., 2012; Chabert et al., 2013).

2.2.2.1 Foam use

Foams have been widely used during EOR operations both for conformance improvement and in-depth gas mobility control, with varying success. The main successes have been for conformance purposes while disappointing results have been obtained for in-depth gas mobility control. A detailed literature review, including pilot trial analyses, can be found here (Enick et al., 2012)

The use of foams to improve underground gas storage has been investigated by several authors (Bernrad et al., 1964; Persoff et al., 1990; Smith et al., 1993). The use of foam for leak remediation in such operations could benefit greatly from the experience gained from the oil industry, especially in conformance remediation and limitation of gas coning from the gas cap (Albrecht and Marsden, 1970; Wong et al., 1997).

For the use of foams as gas flow blocking agents, the foam emplacement, its resistance to gas flow and its durability and stability are of the outmost importance for the efficiency and economics of the process. Though the use of "classical" foams has been considered as a promising technology for controlling excessive GOR, it was shown that these foams have limited lifetime (weeks to months) and the treatment needs to be repeated often (Albrecht and Marsden et al., 1970; Wong et al., 1997; Wassmuth et al., 2001; Cubillos et al., 2012)

These aspects are even more crucial in the case of the use of CO_2-foams for gas leakage prevention/remediation during CO_2 storage operations. Indeed, compared to others foam systems such as N_2-foams or natural gas-foams, CO_2-foams usually generate much lower Mobility Reduction Factors due to the impact of CO_2 on the interfacial tension (Gauglitz et al., 2002; Chabert et al., 2012; Solbakken et al., 2013; Chabert et al., 2014).

In addition, CO_2-foam-induced mobility reduction is very sensitive to the CO_2 density and thus to injection and reservoir conditions of pressure and temperature (Solbakken et al., 2013). Chabert et al. (2014) inferred from a laboratory study that (supercritical) $scCO_2$-dedicated surfactant could improve foam resistance to flow and showed that better mobility reduction could be obtained even with high CO_2 density, but not enough to block gas leakage.

2.2.2.2 Gel Foams

Alternatively, several improvements have been proposed with the objective of increasing the foam-system strength, its resistance to gas flow and its durability once emplaced in the targeted area. This includes mainly polymer enhanced foams and gel foams (Dalland and Hanssen., 1997; Friedmann et al., 1999; Hughes et al., 1999; Wassmuth et al., 2001). From these previous studies, gel-foam appeared to be the more promising technology for gas flow blockage, but it requires a careful design together with an optimization of the strategy of injection and emplacement.

Gel foams consist of gas bubbles in a liquid solution that is able to undergo gelation. They are formed using a surfactant foaming agent usually consisting of a high molecular weight polymer with reactive ends distributed along the molecular chains. Gelation is invoked by a specific cross-linker that is able to react with the polymer reactive ends to form intermolecular bridges and polymer gel. This reaction is controlled using a delaying chemical agent. However, gel-foam application is a very complex process that requires careful investigation to identify an effective solution for a given reservoir application.

One of the most interesting applications of gel foams is to increase well productivity by blocking gas influx. Similarly, they can be used also for confinement purposes to prevent CO_2 leakage across the cap-rock in CO_2 storage.

2.3 Brine/water injection

Brine or water injection has a long history of use for secondary oil recovery worldwide, either to support reservoir pressure or to displace oil towards producing wells. There is a correspondingly wide range of techniques and theories about how water injection can be used to increase oil recovery. Volumetric sweep management and realignment of production in contiguous layers are the nearest analogues in the oil industry to the use of water injection to stop migration of CO_2 (Omorgie et al., 1995).

In CO_2 geological storage there are several mechanisms by which water injection can be used to reduce CO_2 migration. The first and most obvious of these is to form a zone of high pressure in front of the migrating CO_2, sufficient to resist the buoyancy and pressure forces driving the CO_2 forward. This mechanism has been described in general terms by Kuuskraa and Gedec. (2007) as attempting to create an over-pressure in the formation above a leaking caprock and by Réveillère and Rohmer. (2011) with a numerical simulation analysis.

Within MiReCOL this mitigation technique will be addressed both in the context of an overall reservoir management approach to mitigation, and by investigating the local pressure effects of water injection.

The second mechanism is to inject relatively dense brine to form a curtain in front of the advancing CO_2. The aim in this case is to generate sufficient gravitational force on the brine together with local over-pressure from injection to overcome the buoyancy and pressure forces advancing the CO_2, thereby preventing the CO_2 from entering the brine curtain.

This work will concentrate on CO_2 moving in a general lateral direction, under the caprock. Control of vertical migration of CO_2 representing leakage from a fracture in the caprock or a leaking fault will be studied in another part of the project.

The nearest analogue of such a gravity technique in the oil industry is a variant of Water Alternating Gas injection (WAG), namely Simultaneous Water and Gas injection (SWAG) with the aim of increasing secondary oil production. In this case the water and gas are injected at the same time but in separate horizontal wells, with the water being injected higher in the reservoir than the gas in order to restrain the buoyancy effect of the gas by the higher density of the water. Thus the gas sweep in the reservoir is prolonged resulting in additional oil recovery. This technique has been studied first by Stone (2004) and by many later authors such as Jamshidnezhad et al. (2010).

The third mechanism to be considered is that of injecting water directly into the advancing CO_2 plume. This will promote contact between the CO_2 and virgin water, thereby enhancing dissolution of the CO_2 into the water and by reducing the saturation of CO_2 will cause capillary trapping. These mechanisms are normally associated with the tail-end of the CO_2 plume, where the bulk of the CO_2 has moved away and the concentration is dropping. Thus directed water injection is intended to accelerate these processes.

This technique has been studied before e.g. by Esposito and Benson (2010) with respect to leakage mitigation and Anchliya et al. (2012) with the aim of accelerating immobilization of injected CO_2 thus decreasing the storage volume required in a reservoir and the overall risk of leakage. Esposito and Benson (2010) also point out that water injection into the plume spreads the remaining CO_2, making extraction more difficult.

It is intended to investigate the three mitigation techniques outlined above in this part of the project.

2.4 Solid reactants

Limited literature is available on actively changing the permeability of a reservoir to prevent or remediate leakage. More is available on unplanned precipitation by a variety of causes which can clog the reservoir pore space. Injection (and production) of water could induce chemical reactions during oil and gas production (EOR) or geothermal energy. According to Headlee (1945), mineral precipitates formed during oil and gas production are mostly chlorides, sulphates, and bicarbonates of sodium, calcium, magnesium, potassium, strontium and barium. Especially water injection may cause precipitation issues such as the formation of calcium carbonate during re-injection of production water (Rocha et al., 2001; Moghadasi et al., 2004; Birkle et al., 2008) and strontium, barium and calcium sulphates for seawater injection (Delshad and Pope, 2003; Mota et al., 2004; Bedrikovetsky et al., 2006). Mineral clogging in the reservoir is reported to occur in geothermal systems under a wide range of temperature and chemical conditions and may involve precipitation of carbonates, silica (polymorphs), metal compounds (oxides, hydroxides, sulphides, sulphate) and clays (e.g. Kühn et al., 1997; Tarcan, 2005; Izgec et al., 2005; Regensprug et al., 2010). In addition to fluid-fluid reactions, evaporation reactions could also yield mineral precipitation. Salt precipitation and induced clogging of the reservoir porosity is commonly regarded as a potential issue in natural gas and oil production (e.g. Kleinitz et al., 2001) and CO_2 storage in saline aquifers (e.g. Pruess and Müller, 2009; Zeidouni et al., 2009) and depleted gas fields (Giorgis et al., 2007 and Tambach et al., 2014). CO_2 interaction with the host reservoir rock and the pore fluid can also lead to mineral precipitation in the pore space. Much research has been done on this topic since these reactions trap and immobilize the CO_2 which increases the storage safety (e.g. Gaus, 2010). Concerning intentional precipitation within the reservoir, all the mentioned minerals are potential candidates, since there formation has proven to occur 'naturally'.

A couple of studies report on controlled precipitation and permeability decrease (Wasch et al., 2013) proposed salt precipitation around the wellbore as a method for leakage prevention. To precipitate salt in the reservoir, the process of water evaporation into dry gas and subsequent salting-out of the dissolved halite was used. TOUGH2 simulations of multiple cycles of brine and CO_2 injection in the reservoir showed that alternating brine-CO_2 injection could be a promising method for intentional salt-clogging of the near-wellbore area. Intentional salt clogging appears to be particularly suitable for application in depleted gas fields with relatively immobile water and accordingly little chance of re-dissolution of the salt seal by the back-flow of displaced water (Tambach et al., 2014). Selective plugging of well perforations is already practiced in the context of water shut-off during oil production. Plugging reduces water production and enhances oil production from low permeable layers. Plugging agents such as foams and polymers are usually used to clog parts of the reservoir. Selective plugging has also been reported by chemical reactions due to injection of a fluid that is chemically incompatible to the reservoir brine, causing mineral precipitation (Nasr-El-Din et al., 2004). This process is similar to the studies on unplanned precipitation during water injection described above. Looking into specific leakage remediation, bio-mineralization has been proposed (Mitchell et al., 2009, Cunningham et al., 2011). This technique involves engineered biofilms covering grains which will subsequently result in carbonate precipitation by the process of ureolysis. The work of Ito et al. (2014) relates closely to the work planned within MiReCOL. This work reports experiments and modelling of a chemical substance that will react with CO_2 to form a barrier for further CO_2 leakage. They injected both silica and calcium grouts into synthetic porous medium of glass beads. The experimental and modelling work indicates that especially silica has potential as a leakage remediating reactive substance.

3 CONCLUSIONS

This report reviewed flow diversion techniques currently used within the hydrocarbons industry and focused mainly on three processes, namely:

i) Injection of gel or foam,
ii) Injection of water or brine, and
iii) Injection of reactant substances.

A fourth technique, that of injection strategies, has been introduced briefly and is covered in more detail in Deliverable D4.1 "Report on current reservoir pressure management measures in the petroleum industry".

The petroleum industry uses cross-linked hydrolysed polymer-gel injection to improve conformity of fluid flow in the reservoir and to remediate leakage around wells. Polymer-gel solutions are injected to reduce channelling in high-pressure gas floods and to reduce water production from gas wells. More recently, the same process has been suggested for the treatment of fractured rock where relatively strong gels achieve total shutoff due to gel filled fractures. Preliminary laboratory characterisation and assessment for field application of one polyacrylamide based polymer gel system carried out by one of the MiReCOL partners have shown that CO_2 permeability reduction of more than 99% can be achieved in high permeability sandstones. This will form the basis for the characterisation and assessment of a number of polymer gel solutions for the purposes of MiReCOL, which will be used in numerical evaluation of the use of these solutions in diverting flow within the storage reservoir.

The hydrocarbons industry also used foams for gas mobility control, as blocking agents in thief zones and for conformance control in fractures or layered reservoirs. Therefore, besides their use for EOR purposes, they can also be used to secure gas storage operations through gas confinement and gas leakage remediation. However, foams are dispersed systems and are intrinsically unstable with time, yet for conformance and blocking purposes they should remain stable for a given time. It is believed that, in order to increase the foam-system strength, and its resistance to gas flow, polymer enhanced foams and gel foams can be considered. This potential use for flow diversion purposes will be explored by the researchers within MiReCOL.

In CO_2 geological storage there are several mechanisms by which water injection can be used to reduce CO_2 migration. The options to be considered in MiReCOL include: i) forming a zone of high pressure in front of the migrating CO_2 which will be sufficient to resist the buoyancy and pressure forces driving the CO_2 forward; ii) injecting relatively dense brine to form a curtain in front of the advancing CO_2; iii) injecting water directly into the advancing CO_2 plume to enhance dissolution of the CO_2 into the water and achieve capillary trapping.

MiReCOL researchers have, in the past, studied controlled precipitation and permeability reduction by salt precipitation around the wellbore as a method for leakage prevention. In this project, researchers will consider experiments and modelling of chemical grouts, which will react with CO_2 to form a barrier for further CO_2 migration.

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