MUSTANG

A MUltiple Space and Time scale Approach for the quaNtification of deep saline formations for CO2 storaGe

Project Number:227286

Work-Package: WP04

Laboratory experiments and natural analogies

Deliverable D4.7
Guidelines for optimal storage efficiency and injection procedure

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Executive summary

This deliverable summarizes the work conducted in MUSTANG with regard to the optimization of the CO_2 storage and injection. The issue is approached as a reservoir management problem, which can be formalized as a multi-criteria optimization exercise. Optimization measures, which are often conflicting, would include maximizing injectivity, minimizing the volume of the stored CO_2, minimizing the spatial footprint of the CO_2 body etc. Analytical expressions for these measures are provided using quasi-analytical solutions of the CO_2 storage problem of various complexities (single-phase flow, two-phase with sharp interface, full two-phase).

Keywords Injectivity, capacity, containment, two-phase flow, sharp interface, multi-criteria optimization.

Table of Contents

1. Introduction

The optimization of the storage efficiency and injection is a reservoir management problem, which can be defined as a multiple objective problem, characterized by objectives of conflicting nature.

We could define the storage efficiency of a reservoir as the amount of CO_2 that can be sustainably stored per unit volume of a given reservoir

Optimization of injection is a well-known measure of injectivity, I, defined commonly as:

$$I = \frac{Q^m_{CO_2}}{\Delta P}$$

Where $Q^m_{CO_2} = Q^m_{CO_2}(t)$ denotes the, possibly time-dependent, CO_2 mass flow injected into the reservoir and ΔP is the pressure build-up, subsequent to the injection. Pressure build-up can be at the well vicinity or at a selected location within the reservoir.

We could also define an integral measure of the injectivity as:

$$I_I = \frac{\int_{t=t_s}^{t_f} Q^m_{CO_2}(t)dt}{\frac{1}{t_f - t_e}\frac{1}{V_f - V_s}\iint_{t_s,s}^{t_f,V_f} \Delta P(t,x)dV}$$

Where t_e and t_f denote the starting and ending times of the injection and V_s and V_f denote the volume of the stored CO_2 in the reservoir at the start time and end time of the CO_2 injection.

These definitions seem obvious but calculating them for a given reservoir is far from being trivial.

Accordingly, optimization objectives that could be taken into consideration would include: maximizing the volume of the stored CO_2, minimizing the foot-print (specific surface) of the CO_2 body, maximizing the trapping mechanisms (dissolution, capillary, etc.), minimizing environmental impacts (pressure build-up, brine migration, induced seismicity, mineral mobilization), minimization investment in wells, minimization the energy impacts (reducing the energy needed for the injection), preventing and or minimizing leakage, avoid fault reactivation.

The optimization is then conditioned by the reservoir properties (geology, hydraulic properties, thickness, depth, spatial extent, boundary conditions, and pressure and temperature conditions) and the thermodynamic properties of the injected CO_2.

Most of the CO_2 injection projects have not addressed this problem, which is fundamentally a management problem. However, there is an abundant literature addressing these topics, usually punctually and most by means of modelling. This deliverable summarizes the state of the art on the work done, possibly in the field and describes the field experiments at Heletz that aim to address, at least partly, this problem.

2. Literature review

A IEA GHG Literature review and discussion of efficient and cost-effective injection strategies for large scale projects (2011) suggest that Pressure build-up in saline reservoirs is to be considered as the most limiting factor for large scale storage. Pressure management strategies include increasing the number of wells, and adding water production wells - pressure control/relief wells. Both strategies have a substantial economic impact. There are conflicting results in the literature concerning the number of wells. The conclusions drawn from some estimates (Economides, 2009), (Ehlig-Economides, 2010) are that the recommended number of wells renders large scale projects economically infeasible. On the other hand, (Cavanagh et al , 2010) there are only 9 wells in the new large scale Gorgon field in Australia. Water production wells are costly, need a solution for disposal, yet could allow operators to manage to some degree the migration of the co2 plume. This benefit has proven a significant safety benefit in CO2EOR operations and can increase co2 dissolution. (IEAGHG report, 2010). Strategies for increase of dissolution rate and residual trapping include alternate or simultaneous injection of water/brine and co2. As the largest uncertainties are associated with the economics of large scale CCS, the following conclusions refer to the impact of each injection parameter separately on cost: Low permeability values are associated with a large number of injection wells and increased costs. Injection rate: increase leads to increased cost for the same reason. Formation depth has contrasting implications: increase allows increase of pressure buildup and co2 capacity, but increased cost of well digging. Formation thickness: costs increase when thickness decreases.

A technical conflict is encountered towards the optimal operating conditions for simultaneous objectives of higher recovery and higher CO2 storage. In this study, horizontal injection wells have proved to be efficient for CO2 flooding process to improve recovery while increasing the storage of anthropogenic CO 2. Twenty-one different scenarios for two different schemes have been simulated and investigated simultaneously for storage and recovery. The incremental recovery is related to the flood injection operating strategies employed, introducing back pressure on the reservoir through injectors and producers. The CO2 flood front is controlled through horizontal well adjusting pressure, simultaneously adjusting water injection in the offsetting vertical injection wells and holding back pressure on the associated production wells. Efficient back pressure, achieved is by limiting high operating bottomhole pressure of the producers corresponding to those of injectors that helped maximise the vertical sweep. In addition, opting GOR strategy, location of the horizontal well, optimal injection rates helped to achieve conformance within the reservoir that enabled one to overcome the conflict of achieving the simultaneous objectives. (Malik & Islam, 2000).

2.1 Maximizing the storage of CO_2 as a free phase

In its simplest form (assuming storage by displacement and neglecting compressibility) the mass of CO2 that can be stored in a reservoir is determined by the part of the pore space that can be made available for the CO2, can be written as (Bachu et al, 2007):

$$M_{CO_2} = \rho_{CO_2} \phi V_S (1 - S_{wr}) - V_{WB}$$

Where, M_{CO_2} is the mass of the stored CO_2, ρ_{CO_2} is the density of the CO_2, ϕ is the porosity, V_S is the rock volume of the structural trap (underneath a seal), $M_{CO_2} = S_{wr}$ is the residual water saturation and V_{WB} is the volume of the water displaced outside the borders of the residual trap.

Storativity is an additional storage component and depends on the rock compressibility, defined as:

$$C = \frac{1}{V}\frac{\partial V}{\partial p}$$

From the above, it is clear that we can achieve optimal storage by increasing as much as possible the available volume for CO_2 storage. This means for a given reservoir, maximizing the density of the CO_2, both for increasing the overall mass but not less importantly for avoiding/limiting the vertical segregation of the CO_2 due to buoyancy forces, subsequent to the fact that the density of the CO_2 is less than the density of the formation water.

Conditions prevailing at the reservoir boundaries are therefore critical: open boundaries will easily allow water displacement outside the domain of the residual trap. Compressibility plays a role only when the amount of the injected CO2 is substantially smaller than the reservoir volume.

The degree of vertical segregation is driven by the gravity number, which provides information on the relative importance of the gravity forces over the viscous forces:

$$N_g = \frac{Lk_V \Delta\rho g \cos\alpha}{H\mu u_{inj}}$$

Where L is the reservoir characteristic length, H is the reservoir characteristic thickness, k_V is the vertical permeability, $\Delta\rho$ is the density contrast (between CO_2 and the formation water), g is the gravity acceleration, α is the dipping angle of the reservoir, μ is the viscosity of the CO_2 and u_{inj} denotes the injection velocity. The larger the gravity number the larger the impact of buoyancy and vertical segregation. Therefore, dense and viscous CO_2 injected at large rates would tend to limit the vertical segregation. Large anisotropy and small dipping angles would contribute too.

2.1.1 Conditioning of the CO_2

Measures for increasing the CO_2 density would include temperature and or pressure control of the injected CO_2 and mixing the CO_2 stream with additives (usually hydrocarbons) having the capability to modify the thermodynamic properties (the phase envelope) of the injected mixture.

Nazarian et al (2013) suggest the concept of “active plume management (APM)”. The addition of hydrocarbon to the CO_2 stream has the potential to move the critical point to a higher temperature and pressure and thus provide a wider phase envelope within which the density of the CO_2 is much higher at the pressure and temperature conditions of the reservoir. The drawback of this approach is the cost of the hydrocarbons needed for the mixture. Another possibility is to apply cold injection of CO_2, the drawback being the possible adverse geomechanical impacts, mainly on the caprock in reverse faulting stress regimes at early times of injection (Vilarrasa et al., 2013a; 2014).

Nazarian then suggest as part of the APM the concepts Chemical Injection Swings (CIS), Thermal Injection Swings (TIS) or pressure injection swings (PIS). The idea is to judiciously alternate injection of pure (original) CO_2 with conditioned CO_2 of much higher density, where the higher density CO_2 would act as a barrier to the vertical migration of the original CO_2. They demonstrated by means of modeling of the Sleipner and Snohvit reservoir that such approach would dramatically reduce the foot-print of the injected CO_2 body.

They suggest, as part of the APM to use CO_2 from different sources that could be very close to the operational conditions of the Swings (CO_2 rich in hydrocarbons, cold CO_2 etc.). Additional decision variables would include the duration of the swings (time interval of the original CO_2 injection versus the time interval of the conditioned CO_2 injection).

Thermal conditioning of the CO_2 was also suggested by Vilarrasa et al (2013a). They point at a substantial saving of the total energy cost of the CO_2 injection, by injecting cold CO_2, thus reducing the energy cost of the heating and the pressurization cost, as cold CO_2 in the borehole would add substantial driving pressure. Injecting CO_2 in liquid state is energetically more efficient than in supercritical state because liquid CO_2 is denser than $scCO_2$, leading to a lower overpressure not only at the wellhead, but also in the reservoir because a smaller fluid volume is displaced. Cold

CO_2 injection cools down the formation around the injection well. Further away, CO_2 equilibrates thermally with the medium in an abrupt front. The liquid CO_2 region close to the injection well advances far behind the SC CO_2 interface. While the SC CO_2 region is dominated by gravity override, the liquid CO_2 region displays a steeper front because viscous forces dominate (liquid CO_2 is not only denser, but also more viscous than scCO_2). The temperature decrease close to the injection well induces a stress reduction due to thermal contraction of the media. This can lead to shear slip of pre-existing fractures in the aquifer for large temperature contrasts in stiff rocks, which could enhance injectivity. In contrast, the mechanical stability of the caprock is improved in stress regimes where the maximum principal stress is the vertical. (Vilarrasa et al, 2013a).

2.1.2 Pressure control/relief and pore-space optimization

This is probably the most effective and powerful control measure for optimizing CO_2 storage. In order to achieve pressure relief, there is a need to drill abstraction wells in the reservoir. When judiciously placed, pumping wells can dictate the migration direction of the CO_2 body and keep the pressure buildup in the reservoir within desired limits. Pressure relief can also minimize the brine migration and freshwater aquifer pollution. The drawback, however, is the need to drill deep and costly wells, and the need to dispose of the brine that is abstracted. Also care has to be taken in order to avoid breakthrough of the CO_2 body at the abstraction wells.

Possible solutions are to dispose the brine to the sea in coastal areas or to desalinate it in areas where there is no suitable disposal option. These options have been investigated by Buschek et al (2011) and further developed into an integrated platform of water resources management and CO2 storage (see Court et al, 2011). While these concepts are novel, they have not passed yet the techno-economic feasibility analysis. Desalination produces brine that must be disposed (and can't be re-injected as it is far more concentrated).

Bergmo et al (2011) investigated the simultaneous injection of CO_2 and passive production of water, using simulation of passive water production in the Utsira/Johansen formation. While this production method may save costs in the production and operation of the wells, this requires that the aquifer pressure exceeds the hydrostatic pressure near the production wells. A residual pressure increase will therefore propagate past the production wells and into the far parts of the aquifer. The cost of this full-aquifer pressurisation in terms of detrimental effects for future storage operations or other underground resources should be balanced against the increased cost of more active water extraction such as pumping. It is seen that even with passive water production the produced water volume is a significant fraction of the reservoir volume of the injected CO_2. For a large injection operation the produced volumes will be on the order of 1 km^3 water produced per Gigaton of injected CO_2. Both the Utsira and Johansen formations are located far from the shore in the North Sea and it is assumed that an emission permit for the formation water with 3–5% salinity can be obtained. To utilise more than 1–2% of the available pore space massive water production from the formation will be necessary to constrain pressure build-up to within safe limits and to avoid interference with other potential storage projects in the same hydraulic unit. Results from the reference simulations on the full field models indicate that if no water is produced pressure increase in the far parts of the formations is still significant. After 50 years the eastern parts of the Johansen formation have a pressure increase of 20–25 bar, and the pressure increase 80km north of the injection wells in Utsira is 2 bar.

Dempsey et al (2014) developed a Strategy of Passive injection aimed at mitigating reservoir pressurization, induced seismicity and brine migration. Passive injection relies on the strategic placement of brine production wells to create negative pressure gradients that result in CO_2 entering the formation at ambient pressure. Injection occurs at the intersection of pressure-depth profiles for a surface-pressurized, low-density CO_2 column and a hydrostatic column of formation fluid. A multi-stage, square-ring well configuration is envisaged, in which brine production wells are repurposed for CO_2 injection upon CO_2 breakthrough, and the next concentric ring of production wells installed at a greater distance. Numerical simulations confirm the expected outcome of these ideas. However, passive injection produces large quantities of brine, the treatment and disposal of which represents an additional economic burden to CO_2 geologic storage operations. Unless additional revenue streams or economies of scale can be leveraged, these costs are likely to limit the viability of the proposed scheme to only the most economically favourable sites. An alternative to dispose of the pumped brine would be to reinject it together with CO_2, and mix them at the bottom of the well (Pool et al., 2013). In this way, CO_2 would enter the storage formation already dissolved into the brine, eliminating the risk of leakage.

Active pressure relief is actually implemented in the Chevron Gorgon gas reservoir (Australia). The CO_2 produced with the gas (~15%) will be injected in the Dupuy formation, at a depth of 2,500 m. 120 Million tons of CO_2 will be stored. This formation does not have the capacity for this volume of CO_2 and therefore water abstraction wells will be drilled in order to reduce pressure buildup and free pore space for the CO_2.

In reality, chances are that pressure will be relieved by natural leakage across the caprock. While caprocks are selected to ensure low permeability, the reality is that what limits CO2 leakage is entry pressure (i.e., capillarity). Experience dictates that even if local permeability is very small, large flow rates of water can occur across aquitards because (1) the area through which water is flowing increases linearly with time, and (2) scale effects ensure a sizable value for the large scale effective vertical permeability. Therefore, a CO2 leakage free storage can probably be ensured with moderate pressure buildups in most aquifers. The real challenge is whether the leakage is concentrated and, if so, can be properly monitored for adequate control.

2.2 Maximizing the CO_2 trapping

The key trapping mechanisms are dissolution and capillary trapping. Since CO_2 dissolution can be of the order of 5-7% and capillary trapping requires sweeping (migration of the CO_2, pushed by water), this implies actual injection of water together with the CO_2 or in swings.

Nghiem et al. (2009) show that water injection located above the CO_2 injection can enhance both residual gas trapping and solubility trapping. Using simulation, the optimal location and operating conditions for the water injector are determined for both a low-permeability aquifer and a high-permeability aquifer. It is shown that low vertical permeability and water injection at a larger depth favour residual gas trapping while high vertical permeability and water injection at a smaller depth favour solubility trapping. It is also shown that for high-permeability aquifers, water injection does not increase the total CO_2 trapping.

Hassanzadeh et al (2009) suggest to accelerate CO_2 dissolution using the same approach. They investigate the effects of different aquifer properties and determine the rate of solubility trapping in an idealized aquifer geometry. The acceleration of dissolution by brine injection increases the rate of solubility trapping in saline aquifers and therefore increases the security of storage. We show that, without brine injection, only a small fraction (less than 8%) of the injected CO_2 would be trapped by dissolving in formation brine within 200 years. For the particular cases studied, however, more than 50% of the injected CO_2 dissolves in the aquifer as induced by brine injection. Since the energy cost for brine injection can be small (<20%) compared to the energy required for CO_2 compression for a 5-fold increase in dissolution, such reservoir engineering techniques might be viable and practical for accelerating dissolution of CO_2. The environmental benefit would be to decrease the risk of CO_2 leakage at reasonably low cost.

Gilfillan et al. (2009) studied the trapping from natural analogues. Seven natural analogue gas fields has been examined and quantified. Solubility trapping has been found to be the dominant CO_2 sink compared with mineral fixation. In view of these findings that geological mineral fixation is a minor CO_2 trapping mechanism in natural gas fields, it is recommended that long term anthropogenic CO_2 storage models in similar geological systems should focus on the potential mobility of CO_2 dissolved in water.

Juanes et al (2006), Taku et al. (2007) and QI et al (2009) suggest alternating brine and CO_2 injections at high rate as a mean to maximize CO_2 trapping, thus reducing the need for a compact sealing layer (QI et al, 2009). Also Gas injection processes in which gravitational forces are weak compared to viscous forces (low gravity number) tend to trap significantly more CO_2 than do flows with strong gravitational forces, yet the rate at which trapping occurs is higher at high gravity number values. The value of the latter can be adjusted most easily by controlling the CO_2 injection rate. Thus, entrapment through capillary snap-off is optimized for the highest possible injection rate consistent with compression capacity and any formation fracture pressure limitations. Injection schemes such as alternating injection of brine and CO_2 or brine injection after CO_2 injection can also enhance the trapping behaviour. CO_2 dissolution can also be eenhanced by injecting CO_2 under temporal pressure fluctuations (Bolster et al., 2009). The effect of the reservoir inclination on the amount and rate of trapping can be quite significant. When the reservoir is inclined, reduction of gas saturation after injection ceased continued to trap CO_2 as the gravity tongue migrates upward.

2.3 Optimizing injection

The characteristic measure of the injection optimization is the injectivity. For this, we need the capability to calculate the pressure build-up, subsequent to the injection of CO_2. There is abundant literature in oil production, addressing the injectivity (productivity) problem. Many analytical expressions, mostly assuming single phase, steady state flow conditions and simple geometries are available for the case of oil and are applicable for CO_2 storage. One could also consider vertical and horizontal wells.

We can define three levels of increasing complexity for the calculation of the pressure build-up:

1. Assuming single phase flow;
2. Assuming a sharp interface between the injected CO_2 and the formation water;
3. Assuming two-phase CO_2 – H_2O flow.

For relatively simple settings and geometries there are analytical or semi analytical solutions providing close expressions of the pressure build-up. Analytical solutions are very useful as they allow fast though preliminary estimation of the pressure build-up and its dependence of the reservoir conditions.

2.3.1 Injectivity with single-phase flow assumption

This assumption allows deriving a relatively large number of analytical solutions (mostly developed for the purpose of oil reservoir management). The single-phase flow assumption allows considering relatively complex reservoir settings (anisotropy) and well configuration (partial penetration, horizontality).

(Lu, 2009), provides an analytical solution of the injectivity, of a partially penetrating well in anisotropic reservoir of cylindrical geometry as:

$$I = \frac{\rho g k_h}{\mu} \frac{H}{ln\left(\frac{\left(\frac{R_i}{L}\right)\left(\frac{k_a}{k_h}\right)}{\left(\left(\frac{k_h}{k_v}\right)^{\frac{1}{4}} + \left(\frac{k_v}{k_h}\right)^{\frac{1}{4}}\right)\frac{R_w}{2L}}\right) + S_{ps}}$$

Where ρ is density, μ is the viscosity, g is the gravity acceleration, k_h is the reservoir horizontal permeability, k_v is the reservoir vertical permeability, $k_a = k_h^{\frac{2}{3}} k_v^{\frac{1}{3}}$ is the average permeability, R_w is the well radius, R_i is the radius of influence (drainage) of the well, L is the length of the perforation, H is the reservoir thickness ($H \geq L$) and S_{ps} is the pseudo-skin factor representing the pressure losses resulting from the partial penetration.

For no-flow conditions at the top and bottom of the reservoir and constant pressure at the radius of influence, Lu (2009) developed an analytical expression for the pseudo-skin term.

$$S_{ps} = \frac{8H_D^2}{\pi^2 L_{pD}^2} \sum_{n=1}^{\infty} \frac{1}{n^2} K_0\left(\frac{n\pi R_{wD}}{H_D}\right) sin^2\left(\frac{n\pi L_{pD}}{2H_D}\right) cos^2\left(\frac{n\pi (L_{2D} + L_{1D})}{2H_D}\right)$$

Where K_0 is the modified Bessel function of order 0 and:

R_{wD}	$\left(\left(\frac{k_h}{k_v}\right)^{\frac{1}{4}} + \left(\frac{k_v}{k_h}\right)^{\frac{1}{4}}\right)\frac{R_w}{2L}$
H_D	$\frac{H}{L}\left(\frac{k_a}{k_v}\right)^{\frac{1}{2}}$
L_{2D}	$\frac{L_2}{L}\left(\frac{k_a}{k_v}\right)^{\frac{1}{2}}$
L_{1D}	$\frac{L_1}{L}\left(\frac{k_a}{k_v}\right)^{\frac{1}{2}}$
L_{pD}	$L_{2D} - L_{1D}$

Where L_1 denotes the vertical coordinate of the top of the perforation and L_2 is the coordinate of the bottom perforation (vertical coordinate positive downwards).

In case of full well penetration ($H = L$) the pseudo skin term, $S_{ps} = 0$. If in addition to full penetration the reservoir is isotropic $(k_h = k_v = k)$ the injectivity term reduces to the well-known formula:

$$I = \frac{k\rho g}{\mu} \frac{H}{\ln\left(\frac{R_i}{R_w}\right)}$$

For a horizontal well in an anisotropic reservoir and no-flow conditions at the top and constant pressure at the bottom, the injectivity is given by:

$$I = \frac{\alpha\rho g\sqrt{k_h k_v}}{\mu}\frac{L}{\ln\left(\frac{4H_D}{\pi R_{wD}}\right) + \ln\left(\tan\left(\frac{\pi z_{wD}}{2H_D}\right)\right)}$$

Where α is a scalar, L is the length of the well, k_h and k_v are the same as above and

z_{wD}	$\frac{z_w}{L}\left(\frac{k_a}{k_v}\right)^{\frac{1}{2}}$
R_{wD}	$\left(\left(\frac{k_h}{k_v}\right)^{\frac{1}{2}} + \left(\frac{k_v}{k_h}\right)^{\frac{1}{2}}\right)\frac{R_w}{2L}$
H_D	$\frac{H}{L}\left(\frac{k_a}{k_v}\right)^{\frac{1}{2}}$

Where z_w denotes the vertical position of the well (the z coordinate equals 0 at the reservoir bottom and is positive upwards).

These relatively simple expressions assume single-phase flow (no impact of capillary pressure and relative permeability), no chemical reactions (such as salt precipitation), no biological reactions (bacterial development at the well perforation) or mechanical impacts (such as layer degradation). Accordingly, one should use them as first order evaluations.

2.3.2 Injectivity with two-phase flow with sharp interface assumption

Nordbotten et al (2005) developed an analytical solution for the pressure build-up in case of a fully penetrating well in an isotropic and confined reservoir, assuming constant densities and viscosities of the CO2 and the water. The resulting injectivity is given by:

$$I = \frac{2\pi k\rho_c}{\mu_w \int_{R_w}^{R_i} \frac{dr}{r\left(\frac{\mu_w - \mu_c}{\mu_c}(B - h_c) + B\right)}}$$

Where h_c is the water CO_2 interface elevation from the reservoir bottom. It is given by:

$$h_c = B\left[1 - \frac{\mu_w - \mu_c}{\mu_c}\left(\sqrt{\frac{\mu_w Q_c^m t}{\rho_c \mu_c \phi\pi B r^2}} - 1\right)\right]$$

Where:

ρ_c	CO_2 density.
μ_c	CO_2 viscosity.
ρ_w	Water density.
μ_w	Water viscosity.
B	Reservoir thickness.
ϕ	Reservoir porosity.
t	Time.
r	Radial distances.

This time dependent solution can provide information on the evolution of the injectivity with time and with time-varying injection rates. However, it neglects gravity and assumes the dominance of viscous forces.

Dentz and Tartakovsky (2009) with further improvement of Villarasa (2012) for including compressibility suggest a solution that is more representative of flow regimes dominated by gravity. Accordingly, they define three domains at radial distances from the well as follows:

$$D_1:\ r < r_b$$
$$D_2:\ r_b \le r \le R_i$$
$$D_3:\ r > R_i$$

Where r_b and r_t denote the radial distance of the CO_2-Water interface at the reservoir bottom and reservoir top, respectively. From their solution we can derive the following expression for the injectivity:

$$I = \frac{2\pi k \rho_c B}{F(r)}$$

$$F(r) = \begin{cases} \mu_w \ln\left(\frac{R_i}{r_b}\right) + \mu_c \ln\left(\frac{r_t}{r}\right) - \frac{\pi k g B^2 g \rho_c (\rho_w - \rho_c)}{Q_c^m}, r \in D_1 \\ \mu_w \left[\ln\left(\frac{R_i}{r_b}\right) + \gamma_{cw} \ln\frac{r}{r_b} \ln\frac{r_b}{r}\right] + \mu_c \ln\frac{r_b}{r}\left(1 - \gamma_{cw}\ln\frac{r}{r_b}\right) - \frac{\mu_w - \mu_c}{2\gamma_{cw}}, r \in D_2 \\ \mu_w \ln\frac{R_i}{r}, r \in D_3 \end{cases}$$

Where γ_{cw} is a known dimensional number defined as:

$$\gamma_{cw} = \frac{Q_c^m}{2\pi k B^2 \rho_c g} \frac{\mu_w - \mu_c}{\rho_w - \rho_c}$$

And the radial distance of the bottom the interface position at the bottom of the reservoir is given by:

$$r_b(t) = \sqrt{\frac{2 Q_c^m t}{\rho_c \pi \phi B \gamma_{cw}} \frac{1}{e^{\frac{2}{\gamma_{cw}}} - 1}}$$

This time dependent solution addresses flows dominated by gravity.

Both of the above formula assume constant properties of the fluids (CO2 and water) and therefore there is a need to adjust iteratively the values of the CO2 density and viscosity while applying either one of the above solutions (see Vilarrasa, 2010).

2.3.3 Injectivity with two-phase flow

Vilarrasa et al. (2013b) developed a semi-analytical solution for the two-phase flow of CO_2 injection in deep saline formations. They assumed injection of CO_2 through a vertical well, considering both CO_2 compressibility and buoyancy effects in the injection well. Thus, the CO_2 plume does not necessarily occupy the whole thickness of the aquifer. Interestingly, even in the cases in which the CO_2 plume reaches the bottom of the aquifer, most of the injected CO_2 enters the aquifer through the top portion of the aquifer.

Vilarrasa et al. (2013b) formulated the problem in terms of a CO_2 potential that facilitates solution in horizontal layers, with which they discretized the aquifer. Assuming that CO_2 density varies linearly with CO_2 pressure

$$\rho_c = \rho_0 + \beta(P_c - P_0),$$

where ρ_0 is the reference density for the reference pressure P_0 and β is CO_2 compressibility, the injection overpressure is given by

$$\Delta P = \sqrt{\frac{\mu_c}{\pi k \beta}\Phi_c + \frac{\rho_0^2}{\beta^2}e^{-2g\beta(z-z_0)}} - \frac{\rho_0}{\beta},$$

where z_0 is the reference depth and the potential Φ_c reads

$$\Phi_c = \frac{\pi k \rho_0^2}{\mu_c \beta}e^{-2g\beta(z-z_0)}\left(e^{2g\beta h_c} - 1\right),$$

where the head at the well, h_c, and the CO_2 plume thickness are calculated from the solution of the system of two equations given by

$$\frac{\mathrm{d}P_\alpha}{\mathrm{d}z} = -g\rho_\alpha(P_\alpha),\ \alpha = c, w$$

and

$$Q_m = \sum_{j=1}^{m} J_{c,j}\Delta z_j + \bar{\rho}_c \pi r_{if}^2 \varphi(1 - S_{rw})\frac{\Delta z_f}{\Delta t}$$

where Q_m is the prescribed CO_2 mass flow rate, m is the total number of layers in which CO_2 is present, $\bar{\rho}_c$ is the mean CO_2 density in the layer that coincides with the bottom of the CO_2 plume, r_{if} is the interface position at the bottom of the CO_2 plume and Δz_f is the increment of the CO_2 plume thickness at the well at a given time step. The CO_2 mass flow rate at the injection well (r_p) for layer j is

$$J_{c,j} = \frac{\Phi_{c,j}(r_p) - \Phi_j - J_{cz,j+1}\ln(r_j/r_{j+1})}{\ln(r_j/r_p)},$$

The vertical mass flow rate of a layer to its adjacent one is given by

$$J_{cz,j} = \frac{2\pi k k_{rc}\rho_c^2 g}{\mu_c \Delta z_j}(u_j - u_{j+1})\left(r_{j+1} - r_p - r_{j+1}\ln\frac{r_{j+1}}{r_p}\right)$$

and the position of the CO_2 plume at layer j is

$$r_j^{l+1}(z) = \sqrt{\left(r_j^l\right)^2 + \frac{J_{c,j}^l(r_j)\Delta t^{l+1}}{\pi\varphi(1 - S_{rw})\rho_{ci,j}^l}},$$

where superscript l denotes the time step, Δt is increment of time between step l and step $l+1$ and $\rho_{ci,j}$ is the CO_2 density at the interface in layer j.

This solution was programmed in a spreadsheet that can be downloaded from www.h2ogeo.upc.es/publicaciones/2011/Semianalytical_solution.xlsx.
Both CO_2 plume position and fluid pressure compare well with numerical simulations.

Mathias et al. (2011) develop a semi-analytical solution for the two-phase flow brine+CO_2 in a radial geometry.

$$\Delta P = \frac{M_0}{4\pi\rho_C Hk}\begin{cases} \frac{\mu_C q_{D1}}{k_{rs}}\ln\left(\frac{z_T}{z}\right) + \mu_g q_{D2}F_2(z_T) + \mu_b q_{D3}F_1(z_L), & 0 \le z < z_T \\ \mu_g q_{D2}F_2(z) + \mu_b q_{D3}F_1(z_L), & z_T \le z \le z_L \\ \mu_b q_{D3}F_1(z), & z > z_L \end{cases}$$

$$F_1(z) = \begin{cases} E_1(\alpha z), & z_E > \frac{0.5615}{\alpha} \\ (\alpha z_E)^{-1} - \frac{3}{2} + \ln\left(\frac{z_E}{z}\right) + \frac{z - z_L}{z_E}, & z_E < \frac{0.5615}{\alpha} \end{cases}$$

$$\alpha = \frac{M_0\mu_b(c_r + c_b)}{4\pi H\rho_C k}$$

$$z_E = \frac{H\pi\phi\rho_C r_E^2}{M_0 t}$$

$E_1(x) \stackrel{\text{def}}{=} -E_i(-x)$, Ei(x) is the exponential integral function.

$$F_2(z) = \frac{2}{k_{rg0}}\begin{cases} \frac{1}{2}ln\left(\frac{z_c}{z}\right) + \frac{z_L^{1/2} - z_c^{1/2}}{z_c^{1/2}}, & z \le z_c \\ \frac{z_L^{1/2} - z^{1/2}}{z_c^{1/2}}, & z > z_c \end{cases}$$

Where

$z = \frac{H\pi\phi\rho_C r^2}{M_0 t}$ The similarity variable (r is the distance from the injection point, t – time)

z_T, z_L, – Locations of trailing and leading shocks,

z_c – Location of the continuous transition (within the inner zone $z_T \le z \le z_L$) between a constant gaseous saturation and a varying gaseous saturation.

Fluid Properties (input data for the pure CO2 injection case)

P_0 - Initial reservoir pressure

r_W - Well radius

ω_{sb} - Mass fraction of salt for brine free of CO2

ω_{ca} – Mass fraction of CO2 in the aqueous phase.

ω_{wg} – Mass fraction of water in the gaseous phase.

S_{gc} – Critical gas saturation

r_E - Radial extent
M_0 – Injection rate
H – Formation thickness
ϕ - Porosity
$\rho_C = \rho_g$ - Density of CO2
ρ_a - Density of aqueous phase
ρ_b - Density of brine free of CO2
ρ_s – Density of salt
μ_C, μ_g, μ_b – Viscosities of CO2, gaseous phase and brine, respectively
k_{rs} – Permeability reduction factor because of salt precipitation
k - Permeability
k_{rg0} - End-point relative permeability for CO2
k_{ra0} - End-point relative permeability for brine
c_r - Rock compressibility
c_b - Brine compressibility
S_{ar} - Residual brine saturation
In case the injection involves pure CO2:
q_{D1}, q_{D2}, q_{D3} – Total non-dimensional fluxes (in the regions: dry-out $0 \le z < z_T$, where $q_{D1} = 1$, $z_T \le z \le z_L$, and $z > z_L$ respectively.

$$q_{D1} = 1$$

$$q_{D2} = \frac{G_{wT}}{\omega_{wg}(G_{c1} - G_{cT}) + (1 - \omega_{wg})G_{wT}},$$

where

$$G_{wT} = \frac{\rho_a}{\rho_g}(1 - \omega_{ca})(1 - \omega_{sb})S_{ar} + \omega_{wg}(1 - S_{ar})$$

$$G_{c1} = 1 - \frac{\omega_{sb}\rho_b S_{ar}}{\rho_s}$$

$$G_{cT} = \omega_{ca}\frac{\rho_a}{\rho_g}S_{ar} + (1 - \omega_{wg})(1 - S_{ar})$$

$$q_{D3} = q_{D2}\frac{a_{wL}G_{cL} + a_{cL}(G_{w3} - G_{wL})}{a_{w3}G_{cL}}$$

$$a_{wL} = \frac{\rho_a}{\rho_g}(1 - w_{ca}) * (1 - w_{sb})(1 - f_{gL}) + \omega_{wg}f_{gL}$$

$$f_{gL} = \left[1 + \gamma\left(\frac{1 - S_{gL} - S_{ar}}{S_{gL}}\right)\right]^{-1},$$

Where

$$\gamma = \frac{\mu_g k_{ra0}}{\mu_a k_{rg0}}$$

And

$$S_{gL} = A_4 + \sqrt{\frac{m_1}{m_2}} \quad ,$$

$$A_4 = -\gamma(1 - S_{ar})\omega_{ca}\frac{\rho_a}{\rho_g} / \left(\gamma\omega_{ca}\frac{\rho_a}{\rho_g} + 1 - \omega_{wg}\right)$$

$$m_1 = \gamma(1 - S_{ar})(\ A_4\left(1 - \omega_{wg} - \omega_{ca}\frac{\rho_a}{\rho_g}\right) + \ \omega_{ca}\frac{\rho_a}{\rho_g})$$

$$m_2 = (1 - \gamma)\left(-\gamma\omega_{ca}\frac{\rho_a}{\rho_g} + (1 - \omega_{wg})\right)$$

$$G_{cL} = \omega_{ca}\frac{\rho_a}{\rho_g}(1 - S_{gL}) + (1 - \omega_{wg})S_{gL}$$
$$G_{w3} = a_{w3} = \omega_{wb}\frac{\rho_b}{\rho_c}$$
$$G_{wL} = \omega_{wa}\frac{\rho_a}{\rho_g}(1 - S_{gL}) + \omega_{wg}S_{gL}.$$

Finally,

$$z_c = \frac{q_{D2}\gamma}{(1 - S_{ar})}$$
$$z_T = \frac{q_{D2}\omega_{wg}}{\omega_{wa}\frac{\rho_a}{\rho_g}S_{ar} + \omega_{wg}(1 - S_{ar})}$$

Where $z_T < z_c$

$$z_L = \frac{z_c}{\left(\gamma + \frac{S_{gL}}{(1 - S_{ar})}(1 - \gamma)\right)^2}$$

For long times (after 1 year of injection), Mathias (2011 and 2014) suggest a fast solution for the determination of the pressure build-up.

Defining:

$$\Delta P_D = \frac{\mu_w}{\mu_c}(C_r + C_w)\Delta P$$

We can express the injectivity as:

$$I = \frac{4\pi k\rho_c}{\mu_c}\frac{1}{\varepsilon W_{-1}\left(-\frac{\Delta P_D}{\varepsilon}e^{-\frac{\beta}{\varepsilon}}\right)}$$

Where $W_{-1}(x)$ is the Lambert function for negative arguments, which can be approximated as (Mathias, 2014):

$$W_{-1}\left(-\frac{\Delta P_D}{\varepsilon}e^{-\frac{\beta}{\varepsilon}}\right) \approx L_1 - L_2 + \frac{L_2}{L_1} + \frac{(-2 + L_2)L_2}{2L_1^2} + \frac{(6 - 9L_2 + L_2^2)L_2}{6L_1^3}$$

Where

$$L_1 = \ln\left(\frac{\Delta P_D}{\varepsilon}\right) - \frac{\beta}{\epsilon}$$

$$L_2 = \ln(-L_1)$$

$$\beta = P_{rpD} - \frac{\ln\zeta}{k_{rs}} - \frac{\mu_w q_{D3}\gamma}{\mu_c}$$
$$\varepsilon = \frac{\mu_w q_{D3}}{\mu_c} - \frac{1}{k_{rs}}$$

$$\zeta = \frac{\phi\mu_w(C_r + C_w)r^2}{4kt}$$

$$\gamma = \begin{cases} 0.5772 \; if \; \zeta_E > 0.5615 \\ \frac{3}{2} - \frac{1}{\zeta_E} - \ln \zeta_E \; if \; \zeta_E < 0.5615 \end{cases}$$

$$\zeta_E = \frac{\phi\mu_w(C_r + C_w)R_E^2}{4kt}$$

$$P_{rpD} = \frac{1}{\mu_c}\left[\frac{\mu_c}{k_{rs}}\ln Z_T + \mu_g q_{D2} F_2(Z_T) - \mu_b q_{D3} \ln Z_L\right]$$

k_{rs}, the permeability reduction due to salt precipitation is expressed as a power law of the porosity reduction, subsequent to the salt precipitation:

$$k_{rs} = \frac{k}{k_0} = \left[\frac{\phi}{\phi_0}\right]^\eta, \eta \approx 5.7$$

Mathias compares well with the results of the LBNL - TOUGH2 simulations. He obtains goods match between the injection rates obtained from both methods for a given value of the pressure build-up.

In all the calculations we need to determine the radius of influence of the injecting well. Vilarrasa et al. (2010) derived a time dependent expression, equating the steady state Thiem's (1906) solution with the transient Jacob's (1946). Equating these two terms implicitly assumed instantaneous steady state. The resulting expression of the radius of influence is:

$$R_i = \sqrt{\frac{2.25kt}{\mu_\alpha(\phi C_\alpha + C_r)}}$$

Another possibility is the Sichardt formula:

$$R_i = 3000 \, \Delta P \sqrt{\frac{k}{\rho_\alpha \mu_\alpha g}}$$

Where α denotes the phase occupying the reservoir (=w or c). Using the Sichardt would add non-linearity to the calculation of the pressure build-up.

In the case of vertical well, injectivity will increase with permeability, reservoir thickness, well radius and anisotropy. It will decrease with viscosity and radius of influence. In the case of a horizontal well the injectivity increases with the well length. It will decrease with anisotropy.

Thus, optimal storage and optimal injectivity seem to be in conflict. For instance, a small viscosity improves injectivity but degrades the storage as it enhances vertical segregation. A large anisotropy will degrade the storage and injectivity of a vertical well. However, it will degrade the injectivity of a horizontal well.

Other factors that have an impact on injectivity are salt precipitation. According to Pruess and Müller (2009), Peysson et al. (2013) the injection of CO_2 may induce the development of a dry-out zone around the injection well there are salt precipitates. This would reduce permeability followed by induced high pressure. They suggest injection of pure water prior to beginning of CO_2 injection to reduce the extent of precipitation. According to the analytical model of Matthias, flux reduction resulting from salt precipitation is of a few percent of the original injected flux. Also injection of fresh water as a mean to prevent salt precipitation can lead to adverse effects, such as bacteria development at the well perforation, metal precipitation and or clay swelling, all this leading to well clogging. This has been experienced in Ketzin where they injected fresh water prior to injecting CO2 and at Heletz where use was made of freshwater in order to flush the casing after the cementation and before the perforation.

Malik and Islam (2000) suggest optimizing Enhanced Oil Recovery and Greenhouse Gas Storage via Horizontal Wells. A technical conflict is encountered towards the optimal operating conditions for simultaneous objectives of higher recovery and higher CO_2 storage. In this study, horizontal injection wells have proven to be efficient for CO_2 flooding process to improve recovery while increasing the storage of anthropogenic CO_2. Twenty-one different scenarios for two different schemes have been simulated and investigated simultaneously for storage and recovery. The incremental recovery is related to the flood injection operating strategies employed, introducing backpressure on the reservoir through injectors and producers. The CO_2 flood front is controlled through horizontal well adjusting pressure, simultaneously adjusting water injection in the offsetting vertical injection wells and holding backpressure on the associated production wells. Efficient backpressure, achieved is by limiting high operating bottom-hole pressure of the producers corresponding to those of injectors that helped maximise the vertical sweep. In addition, opting GOR strategy, location of the horizontal well, optimal injection rates helped to achieve conformance within the reservoir that enabled one to overcome the conflict of achieving the simultaneous objectives.

Petvipusit et al (2013) suggest using multiple well CO_2 injection and subsequent management of the system through a multi-criterion optimization to handle the conflicting objectives: economic efficiency, sufficient capacity and long-term security of the storage formation. In addition, the CO_2 injection management is robust against model uncertainty. For the uncertainty assessment, the impact of the model uncertainty to the outcomes is significant. They suggest using the mixture distribution of the objective-function values, as opposed to the traditional Gaussian distribution to cover model uncertainty.

3. Summary of main findings

We summarize below the main findings for the literature review:

1. The storage of CO_2 will be enhanced by maximizing the pore space occupation per unit area of reservoir by limiting the gravity segregation. This would require injecting heavy and viscous CO_2. This approach should be preferred when there is a high degree of certainty with regard to the sealing properties of the caprock.

2. Dissolution and capillary trapping could remove substantial amounts from the CO_2 body (up 15-20%) but this would require the injection of large amounts of water for sweeping purposes. Therefore, this would reduce the volume available for storage. This approach should be preferred when there is substantial uncertainty with regarding to the sealing properties of the caprock.

3. Brine abstraction is a key measure in reservoir management as it can contribute to controlling pressure build-up and keep its impacts within safe and acceptable limits.

4. CO_2 conditioning (by temperature control, addition of chemicals and or pressure control) can tune the thermodynamic properties of the injected CO_2 to the reservoir conditions in order to achieve optimal storage conditions.

5. Well injectivity depends heavily on the reservoir conditions (permeability, anisotropy, reservoir thickness, perforation length), well design (horizontal, vertical, position within the reservoir, length of perforation), and CO_2 properties (essentially the viscosity).

Some of the objectives seem to be contradictory: we cannot maximize trapping and CO_2 pore space filling per unit area of reservoir. Minimizing vertical segregation by injecting cold CO_2 would reduce injectivity but also the energy cost of the injection. High anisotropy would reduce injectivity but increase vertical segregation. This is a multiple-criteria decision making process that could be formulated as a multiple objective optimization problem that should be constrained by the reservoir properties (permeability, anisotropy, compressibility, depth, pressure and temperature, integrity of the seal etc.). Decision variables would be CO_2 pressure, temperature and injection flow-rate, rates of water abstraction. Objective functions minimizing the pressure build-up, maximizing the trapping, maximizing the amount of stored CO_2, minimizing the energy of injection.

4. Experiments to be conducted at Heletz

The experimental sequence at Heletz (in the frame of both the MUSTANG, TRUST and CO2Quest) projects will provide the opportunity to validate some of the storage and injectivity optimization aspects and to generate datasets for model validation. These include:

1. Investigation of injectivity and its evolution with time;
2. Impact of pressure relief;
3. Impact of CO_2 temperature / pressure;
4. Investigation of the trapping mechanisms;
5. Impact of impurities.

4.1 Injectivity and its evolution with time

CO_2 will be injected and pressure and temperature will be continuously monitored over time. Pressure will be measured also in the monitoring well thus providing the opportunity to measure field values of the injectivity, as the mass flow-rate of the CO_2 will be measured too.

4.2 Impact of pressure relief

The two well dipole experiment to be conducted at Heletz (injecting CO_2 in the injection well and simultaneously abstracting fluid from the monitoring well) will allow having field data on pressure relief, by comparing with pressure data obtained when injecting CO_2 without abstraction. The available dataset would be used in order to determine the key factors affecting pressure relief at field scale and to form a dataset for model validation and for the determination of validity limits of the simplified solutions.

4.3 Impact of trapping

The single well push-pull experiment and two-well dipole experiment to be conducted at Heletz in the frame of MUSTANG, will allow determining field values of key trapping parameters and their sensitivity on reservoir heterogeneity. A by-product of these experiments will be a better understanding of the dependence of these parameters on the reservoir properties and on the conditions of the stored CO_2.

4.4 Impact of the injected CO_2 temperature/pressure

The injection module at Heletz allows a wide flexibility for setting the pressure and temperature conditions of the CO_2 at the wellhead and thus and the well bottom. It is planned to conduct an injection of cold CO_2 at Heletz, in the frame of the TRUST project. The monitoring system in place will allow determining the degree of vertical segregation and the energy foot-print of the injection.

4.5 Impact of impurities in the CO_2 stream

An experiment aimed evaluating the impact of SO_2 and N_2 in the injected CO_2 will be conducted at Heletz. While keeping impurities in the CO_2 stream can greatly reduce the cost of the CO_2 separation, there is a need to determine their impact on the reservoir properties and responses. Impact on the trapping (dissolution and capillary trapping) will be evaluated too.

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