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Coupled reservoir-geomechanical analysis of CO_2 injection and ground deformations at In Salah, Algeria

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Abstract: In Salah Gas Project in Algeria has been injecting 0.5-1 million tonnes CO_2 per year over the past five years into a water-filled strata at a depth of about 1,800 to 1,900 m. Unlike most CO_2 storage sites, the permeability of the storage formation is relatively low and comparatively thin with a thickness of about 20 m. To ensure adequate CO_2 flow-rates across the low-permeability sand-face, the In Salah Gas Project decided to use long-reach (about 1 to 1.5 km) horizontal injection wells. In an ongoing research project we use field data and coupled reservoir-geomechanical numerical modeling to assess the effectiveness of this approach and to investigate monitoring techniques to evaluate the performance of a CO_2-injection operation in relatively low permeability formations. Among the field data used are ground surface deformations evaluated from recently acquired satellite-based inferrometry (InSAR). The InSAR data shows a surface uplift on the order of 5 mm per year above active CO_2 injection wells and the uplift pattern extends several km from the injection wells. In this paper we use the observed surface uplift to constrain our coupled reservoir-geomechanical model and conduct sensitivity studies to investigate potential causes and mechanisms of the observed uplift. The results of our analysis indicates that most of the observed uplift magnitude can be explained by pressure-induced, poro-elastic expansion of the 20 m thick injection zone, but there could also be a significant contribution from pressure-induced deformations within a 100 m thick zone of shaly sands immediately above the injection zone.

Keywords: geological CO_2 sequestration; In Salah; geomechanics; ground surface deformations; modeling, InSAR

1. Introduction

The In Salah Gas project (a joint venture between Sonatrach, BP, and StatoilHydro) located in the central region of Algeria, is the world's first industrial scale CO_2 storage project in the water-leg of a depleting gas field (Figure 1). Natural gas produced from the area is high in CO_2 and the CO_2 is being returned to the earth for geological storage. About 0.5-1 million tonnes CO_2 per year has been injected since August 2004 into a relatively low-permeability, 20 m thick, water-filled carboniferous sandstone at a depth of about 1,800 to 1,900 m, around the Krechba gas field (Wright, 2006; Mathieson et al., 2008). To ensure adequate CO_2 flow-rates across the low-permeability sand-face, the In Salah Gas Joint Venture (JV) decided to use long-reach (about 1 to 1.5 km) horizontal injection wells.

The storage formation is an excellent analogue for large parts of North-West Europe and the US Mid-West, where large CO_2-storage will be required if CO_2 Capture and geological storage (CCS) is to make a significant contribution to addressing CO_2 emissions (Wright, 2006). The In Salah Joint Industry Project (JIP) has been launched for research and development and CCS demonstration at In Salah with widespread participation from research and development organizations in both academia and private industry. The storage location is instrumented and data is being collected and analyzed, to monitor location and behavior of the CO_2.

Because of a relatively deep reservoir, a relatively stiff overburden, and the volume of CO_2 being injected is fairly small compared to the overburden, the initial view of the In Salah JIP was that no significant ground deformations would occur. However, in the fall of 2006 a preliminary reservoir-geomechanical analysis conducted at the Lawrence Berkeley National Laboratory (LBNL) using the TOUGH-FLAC numerical simulator (Rutqvist et al., 2002) indicated that surface deformations on the orders of centimeters would be feasible. As a result, the LBNL decided to explore the possibility of using the satellite-based inferrometry (InSAR) for detecting ground surface deformations related to the CO_2 injection. InSAR data were acquired and analyzed by Tele-Rilevamento (TRE), using a state-of-the-art permanent scatterer method (PS) enabling determination of millimeter-scale surface deformations. The results processed in 2007 and later published in Vasco et al. (2008a, b) were remarkable, because the observed uplift could be clearly correlated with each injection well (with uplift bulges of several km in diameter centered around each injection well). Measured uplift occurred within a month after start of the injection and the rate of uplift was approximately 5 mm per year amounting to about 1.5 cm in the first 3 years of injection. (Vasco et al., 2008a, b). Subsequently, a similar uplift pattern was obtained by Onuma and Ohkawa (2008) using the alternative processing technique of Differential InSAR (DInSAR). One reason for the success of the InSAR technology at Krechba is the fact that the ground surface consists of relative hard desert sediments and bare rock.

The uplift data and its correlation with underground reservoir structures are currently under investigation by several research groups within the In Salah JIP using various strain inversion techniques and coupled modeling approaches (Mathieson et al., 2008; Vasco et al., 2008a and b; Ringrose et al., 2009). Vasco et al. (2008a and b) used the observed uplift pattern and performed semi-analytical coupled mechanical-hydraulic inversions of reservoir properties. Specifically, Vasco et al. (2008a and b) estimated reservoir volume changes, then mapped such changes into pressure change and finally inferred a reservoir permeability field.

In this paper we present a completely different approach from that of Vasco et al. (2008a and b). We not conducting an analytical inversion, but a forward coupled reservoir-geomechanical modeling of the actual CO_2 injection at Krechba. In this approach we simulate the CO_2 injection in a 3-dimensional model around one horizontal injection well, and conduct sensitivity studies to determine the cause and mechanism of the uplift. We apply the TOUGH-FLAC simulator that has been previously applied to both generic and site specific studies involving supercritical CO_2 injection, geomechanics, and ground surface deformations (Rutqvist and Tsang 2002; Todesco et al., 2006; Rutqvist et al., 2007; Rutqvist et al., 2008; Cappa et al., 2009). In this first preliminary study on the Krechba CO_2 injection, we are not attempting to make an exact inversion of the uplift pattern around the three injection wells, but rather we focus on a simplified geological representation, yet involving all the key geological features (including reservoir, caprock, and overburden), and processes (multi-phase CO_2-brine flow interactions and coupled geomechanical changes). In particular we investigate whether the observed uplift can be explained by injection-induced pressure changes and deformations within the injection zone. If the uplift can be explained by pressure changes within the injection zone it would indicate that the injection-induced fluid migrations and the injected CO_2 are confined within the injection zone itself.

2. Krechba site and observed ground deformations

The Krechba field is defined by the structural high of a northwest-trending anticline. Gas produced from this field and two nearby fields contains CO_2 concentrations ranging from 1% to 9%, which is above the export gas specification of 0.3%. The CO_2 from the three fields is separated from the hydrocarbons and reinjected into three adjacent wells "KB-501, KB-502, and KB-503" at the rate of tens of millions of cubic feet per day (Figure 1 and 2). The injection is restricted to a 20-m-thick layer, at about 1,800 to 1,900 m depth (Wright, 2006). The reservoir is overlain by more than 900 m of low permeability mudstones, which forms a significant barrier to flow (Figure 1). LBNL and TRE, in partnership with BP, examine the utility of satellite distance change data for monitoring the reservoir during CO_2 injection. Of particular interest is the identification of features controlling flow and the possibility of detecting CO_2 migration out of the reservoir and into the lower parts of the caprock. Because the reservoir initially is water filled, the injection of CO_2 into the water column induces multiphase flow. The CO_2 behaves supercritically at reservoir pressures, with a viscosity and density only moderately different from water (Vasco et al., 2008a).

Figure 2a presents average rate of distance between the satellite and the groundsurface. The distance is measured at a steep angle along the line site and the resulting average distance change is close to the average vertical surface displacements. The CO_2 injection commence in August 2004 at KB501 and KB503, and April 2005 at KB502. During injection, the bottom hole pressure is limited to below the fracturing gradient leading to a maximum pressure increase of about 10 MPa above the ambient initial formation pressure. Figure 2a shows the average vertical uplift of about 5 mm per year above each of the three injection wells. In the Krechba gas field, located between the three injection wells, a small surface subsidence is believed to be a result of production-induced pressure depletion.

Figure 2b shows the time evolution of vertical displacement for one PS point located above KB501, indicating a gradual uplift from August 2004, when CO_2 injection commenced. The KB501 injection data shows continuous CO_2 injection at a more or less constant well head pressure from the start of the injection and the injection rate averaged at about 10 to 15 MMscfd (million standard cubic feet per day). The gradual vertical uplift with time observed in Figure 2b indicates that the uplift does not react instantaneously to injection pressure, but rather appears to be correlated with the injected volume. However, processed and smoothed distribution of surface uplift data presented in Vasco et al. (2008a) shows a clear uplift signature around KB501 already after 24 days of injection. The injection and uplift responses at the KB503 injection well show similar behavior as at KB501. At the KB502, on the other hand, the injection scheme has been more complex with more variations of the injection rates and the uplift pattern is also more complex with two parallel uplift lobes rather than one single uplift lobe. The two uplift lobes was interpreted in Vasco et al. (2008b) to be caused by pressure diffusion along two parallel permeable zones within reservoir. That would suggest that permeability at KB502 is strongly heterogeneous affected by the degree of fracturing and perhaps by intersecting faults (Ringrose et al., 2009).

3. Model Setup

The simulation problem was discretized into a 3-dimensional mesh, 10 by 10 km wide and 4 km deep around one horizontal injection well, which was located at a depth of about 1,810 m below ground level within the 20 m thick injection formation, the so-called C10.2 sandstone (Figure 3). The model consists of four main geological layers as published in the literature (IPPC 2005; Raikes et al. 2008; Iding and Ringrose 2008): (1) Cretaceous sandstone and mudstone overburden (0-900 m), (2) Carboniferous mudstones (900-1,800 m), C10.2 sandstone (1,800-1,820 m), and (4) D70 mudstone base (below 1,820 m).

Table 1 presents the material properties for the coupled reservoir-geomechanical simulation of the In Salah CO2 injection. Initial estimates of the elastic properties of the injection formation were derived from laboratory experiments by the University of Liverpool, U.K, whereas the properties of other geological layers were estimated using sonic logs. For the injection zone, a Young's modulus E = 6 GPa and a Poisson's ratio ν = 0.2 were adopted from a few laboratory experiments on C10.2 samples that had a porosity ranging from 15 to 20 %, consistent with estimates of in situ porosity. From the sonic logs we estimated that the caprock (Carboniferous mudstone and tight sandstone) is somewhat stiffer and that the shallow overburden (Cretaceous sandstones and mudstones) is somewhat softer (Table 1).

The permeability of the injection zone was estimated to 1.3×10^{-14} m^2 (13 mDarcy) by model calibration to achieve a reasonable pressure increase of about 10 MPa (approximate value of pressure increase in the field) for an adopted injection rate of 15

MMscfd. This is within the range of observed permeability range (Iding and Ringrose, 2008). The caprock permeability was varied from 1×10^{-21} to 1×10^{-19} m^2, a reasonable range for shale and mudstone seals (Zhou et al., 2008) and also within the range of recent results from laboratory experiments conducted by the University of Liverpool. The porosity of the injection zone was set to 17% based on in situ estimates from borehole logging and seismic surveys. The parameters defining the capillary pressure and relative permeability functions of the different layers are taken from previous modeling studies of CO_2 injection in deep reservoir-caprock systems (Zhou et al., 2008; Rutqvist et al., 2008; Pruess et al., 2001).

An initial temperature, pressure and stress gradients were derived from site investigations at Krechba. With the adopted gradients, the initial temperature and pressure at the depths of the modeled injection zone is about 90°C and 17.9 MPa, respectively.

The lateral boundaries are set to a constant fluid pressure, temperature and stress, whereas the bottom (at 4 km depth) is a no flow boundary with vertical displacement fixed to zero. At the site, a strike-slip stress regime has been inferred, in agreement with regional data, where the maximum horizontal stress (NW-SE) is greater than the vertical stress (Iding and Ringrose, 2008). In fact, the horizontal CO_2 injection wells were drilled perpendicular to the maximum stress and dominant fracture orientation to maximize injectivity (Ringrose et al., 2009). However, in the current simulation the applied stress magnitude has no impact on the calculated surface uplift since a linear poro-elastic medium is assumed. Thus, it is assumed that the injection does not give rise to any significant in-elastic geomechanical responses such as shear slip or fracturing. This is consistent with the injection pressure being limited to below the fracturing gradient that has been estimated by leak-off tests at the site.

The modeling was conducted for a constant injection rate of 15 MMscfd over a time period of 3 years, approximately representing the average injection rates at KB501 and KB503.

4. Simulation results with comparison to measured surface uplift

Figure 4 shows the simulation results of vertical displacement and changes in reservoir fluid pressure in the case of a very low permeability caprock. Also in Figure 5, the calculated results are compared to measured uplift above CO_2 injection wells KB501 and KB503. In general, the simulation results show consistently with measured data that the uplift increases gradually with time during the simulated 3-year CO_2 injection. Figure 5 indicates a significant impact of caprock permeability on the magnitude of surface uplift. When caprock permeability is set to 1×10^{-21} m^2, the uplift is determined by the volumetric expansion of the injection zone as a result of injection induced pressure changes and associated reduction in vertical effective stress. Increased fluid pressure within the injection zone results in a vertical displacement of about 1.6 cm at the top of the injection zone and an attenuated uplift of about 1.2 cm of the ground surface (Figure 4a). Figure 4b shows that the uplift is correlated changes in fluid pressure within the reservoir, whereas the spread of the CO_2 is much smaller.

When increasing the caprock permeability from 1×10^{-21} m^2 to 1×10^{-19} m^2, the maximum uplift of the ground surface increases from 1.2 to 2.0 cm (Figure 5). When the caprock permeability is 1×10^{-19} m^2 a slight amount of fluid migrates into the caprock and causes an increase in fluid pressure within the caprock, just above the injection zone (Figure 6). This increased caprock fluid pressure causes additional volumetric expansion that significantly contributes to the magnitude of ground uplift. For a permeability of 1×10^{-19} m^2 this pressure increase occurs only in the very lowest part of the caprock, i.e. limited to within about 100 m above the injection zone. It is caused by a small amount of water permeating into the lower pars of the caprock, which has a relatively small effective porosity of 0.01.

The comparison of calculated and measured results in Figure 5 shows that the measured uplift spans the range of the calculated uplift from an impermeable caprock ($k_{cap} = 1 \times 10^{-21}$ m^2) and to a slightly permeable caprock ($k_{cap} = 1 \times 10^{-19}$ m^2). The measured uplift at KB501 closely follows the calculated uplift for the case of a caprock permeability of 1×10^{-21} m^2. Thus, this could be interpreted such that the observed uplift at KB501 is caused by pressure-induced vertical expansion of the C10.2 injection zone itself. The result of measured uplift at KB503 closely resembles the calculated uplift for the case of a caprock permeability of 1×10^{-19} m^2. This could be interpreted such that the uplift at KB503 is caused by pressure-induced vertical expansion of the C10.2 injection zone with an additional contribution from pressure-induced changes within the lowest part of the caprock. In Krechba, this lowest part of the caprock is the approximately 100 m thick sandy shale layer located just above the injection zone (Iding and Ringrose, 2008) and considered to be a secondary storage zone for the injected CO_2.

5. Concluding remarks

This paper present the progress in coupled reservoir-geomechancial modeling of CO_2 injection and ground surface deformations at In Salah, Algeria. We used surface deformations evaluated from recently acquired satellite-based inferrometry (InSAR). The InSAR data shows a surface uplift on the order of 5 mm per year above active CO_2 injection wells and the uplift pattern extends several km from the injection wells. Figure 7 summarizes the preliminary results achieved from the model simulations presented in this paper. Our analysis shows that the observed uplift is consistent with volumetric expansion of reservoir rocks within the 20 m thick injection zone and perhaps within the approximately 100 m thick zone of shaly sands located just above the injection zone. The uplift depends on the magnitude of pressure change, injection volume, and elastic properties of the reservoir and overburden. Future studies will included a refined model, exact variable rate injection scheme, as well as comparison to both uplift magnitude and shape of uplift lobes.

Acknowledgments

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Figure 1. Schematic vertical cross section through the Krechba field (modified from Wright [2006] and Mathieson et al., [2008]).

Figure 2. InSAR data of distance change evaluated by TRE: (a) Rate of vertical displacements at 3 years, and (b) time evolution of vertical displacement for one PS point located above KB501.

Figure 3. Model geometry for the TOUGH-FLAC coupled reservoir-geomechanical analysis of CO_2 injection and ground surface deformations at Krechba. The model is centered on one CO_2 injection well and consists of about 10,000 gridblocks.

Figure 4. Simulated vertical displacement (a) and changes in fluid pressure (b) after 3 years of injection with an impermeable caprock ($k=1\times10^{-21}$ m^2).

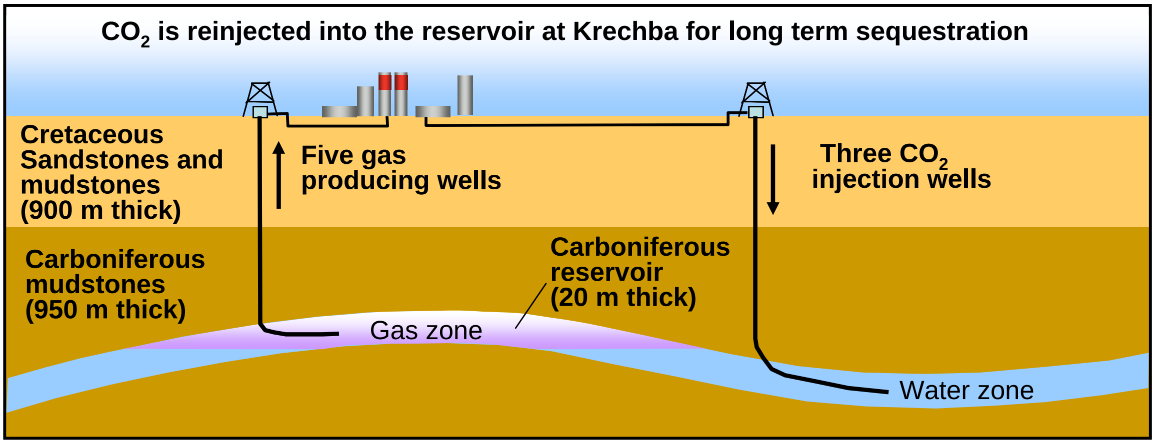
Figure 5. Comparison of simulated vertical ground uplift for two different values of caprock permeability (solid lines) to that of measured ground uplift above injection wells KB501 and KB503 (symbols). The measured data at KB501 and KB503 was evaluated from InSAR data by TRE on the behalf of LBNL.

Figure 6. Vertical profiles of (a) change in fluid pressure and (b) vertical displacement. The figure shows how increased fluid pressure in the lower part of the caprock causes significant uplift in the case of a slightly permeable caorck ($k=1\times10^{-19}$ m^2).

Figure 7. Schematic vertical cross section summarizing results achieved in this study. The dashed lines represent isobar of fluid pressure that propagates from the injection well laterally within the injection zone as well as upwards into the secondary storage zone of shaly sands.

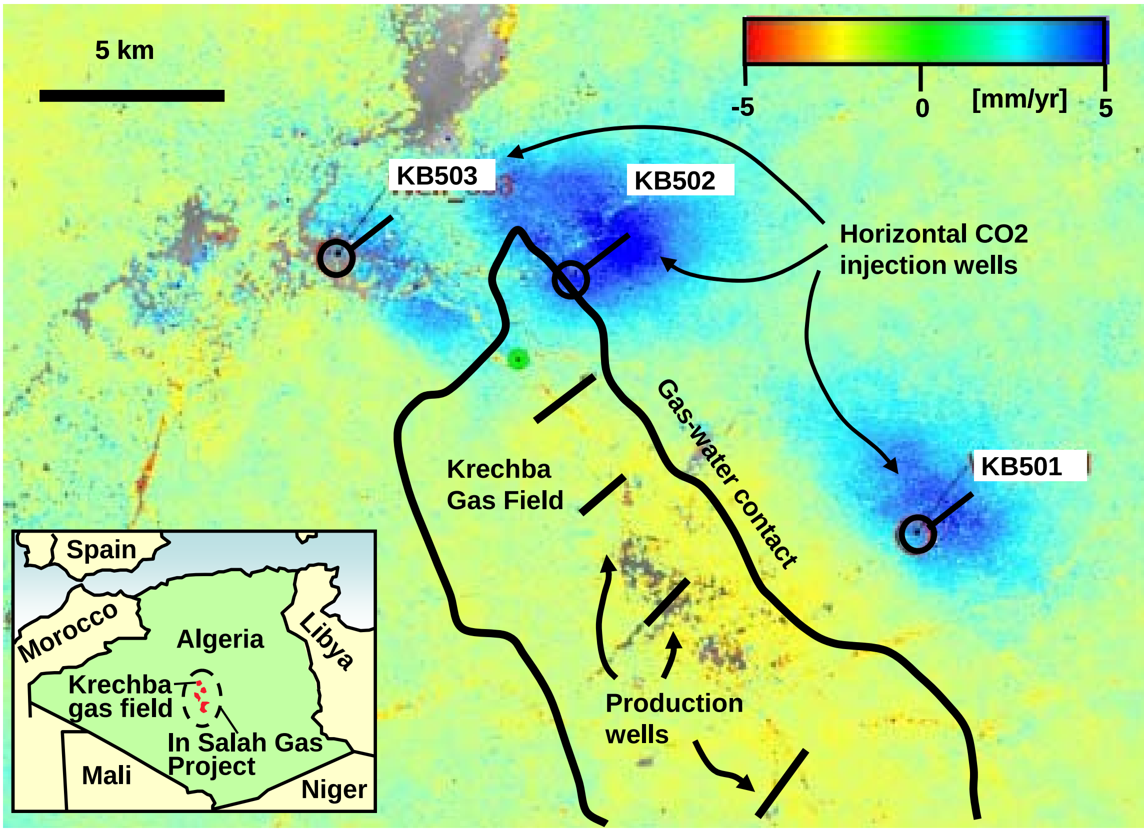
Table 1. Material properties used in the modeling CO_2 injection at In Salah

Layer	**Shallow Overburden (0-900 m)**	**Caprock (900-1800 m)**	**Injection zone (1800-1820 m)**	**Base (below 1800)**
Lithology	**Cretaceous sandstones and mudstones**	**Carboniferous mudstones**	**Carboniferous Sandstone (C10.2)**	**Mudstone (D70)**
Young's modulus, E (GPa)	1.5	20	6	20
Poisson's ratio, ν (-)	0.2	0.15	0.2	0.15
Effective porosity, ϕ (-)	0.1	0.01	0.17	0.01
Permeability, k, (m^2)	1×10^{-17}	1×10^{-21}, 1×10^{-19}	1.3×10^{-14}	1×10^{-19}
Residual gas (CO_2) saturation (-)	0.05	0.05	0.05	0.05
Residual liquid saturation (-)	0.3	0.3	0.3	0.3
van Genuchten (1980), P_0 (kPa)	19.9	621	19.9	19.9
van Genuchten (1980) m (-)	0.457	0.457	0.457	0.457

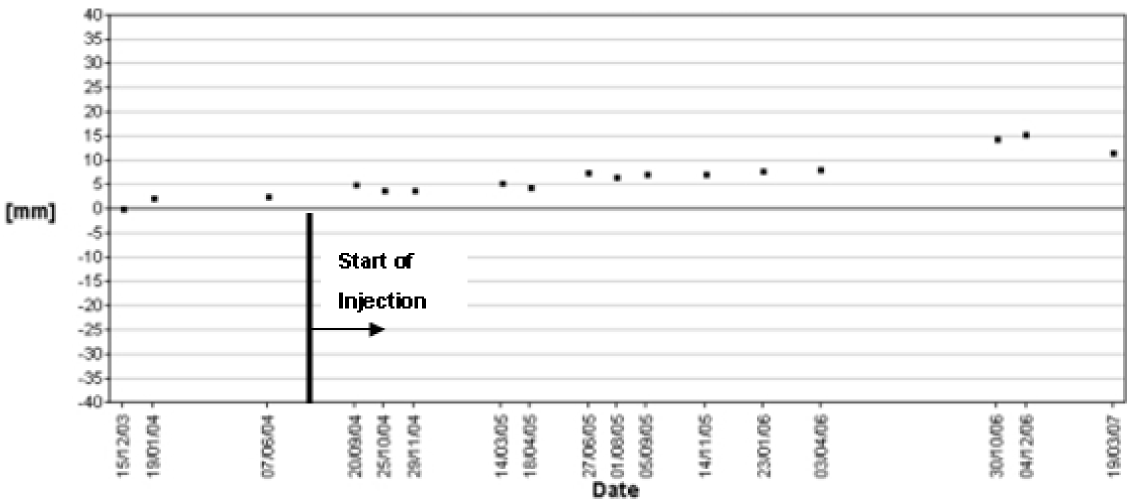


CO_2 is reinjected into the reservoir at Krechba for long term sequestration
Cretaceous Sandstones and mudstones (900 m thick)
Five gas producing wells
Three CO_2 injection wells
Carboniferous mudstones (950 m thick)
Carboniferous reservoir (20 m thick)
Gas zone
Water zone

Figure 1.

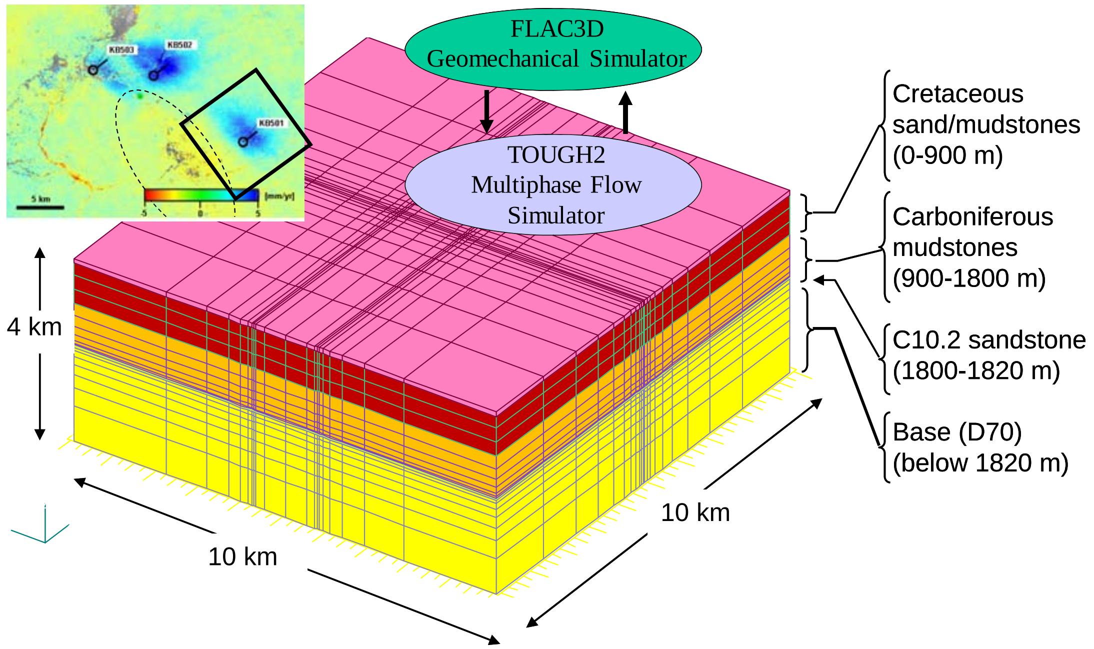

5 km
-5
0
[mm/yr]
5
KB503
KB502
Horizontal CO2 injection wells
Gas-water contact
Krechba Gas Field
KB501
Production wells
Spain
Morocco
Algeria
Libya
Krechba gas field
In Salah Gas Project
Mali
Niger

(a)


[mm]
Start of Injection
Date
15/12/03
19/01/04
07/06/04
20/09/04
25/10/04
29/11/04
14/03/05
18/04/05
27/06/05
01/08/05
05/09/05
14/11/05
23/01/06
03/04/06
30/10/06
04/12/06
19/03/07

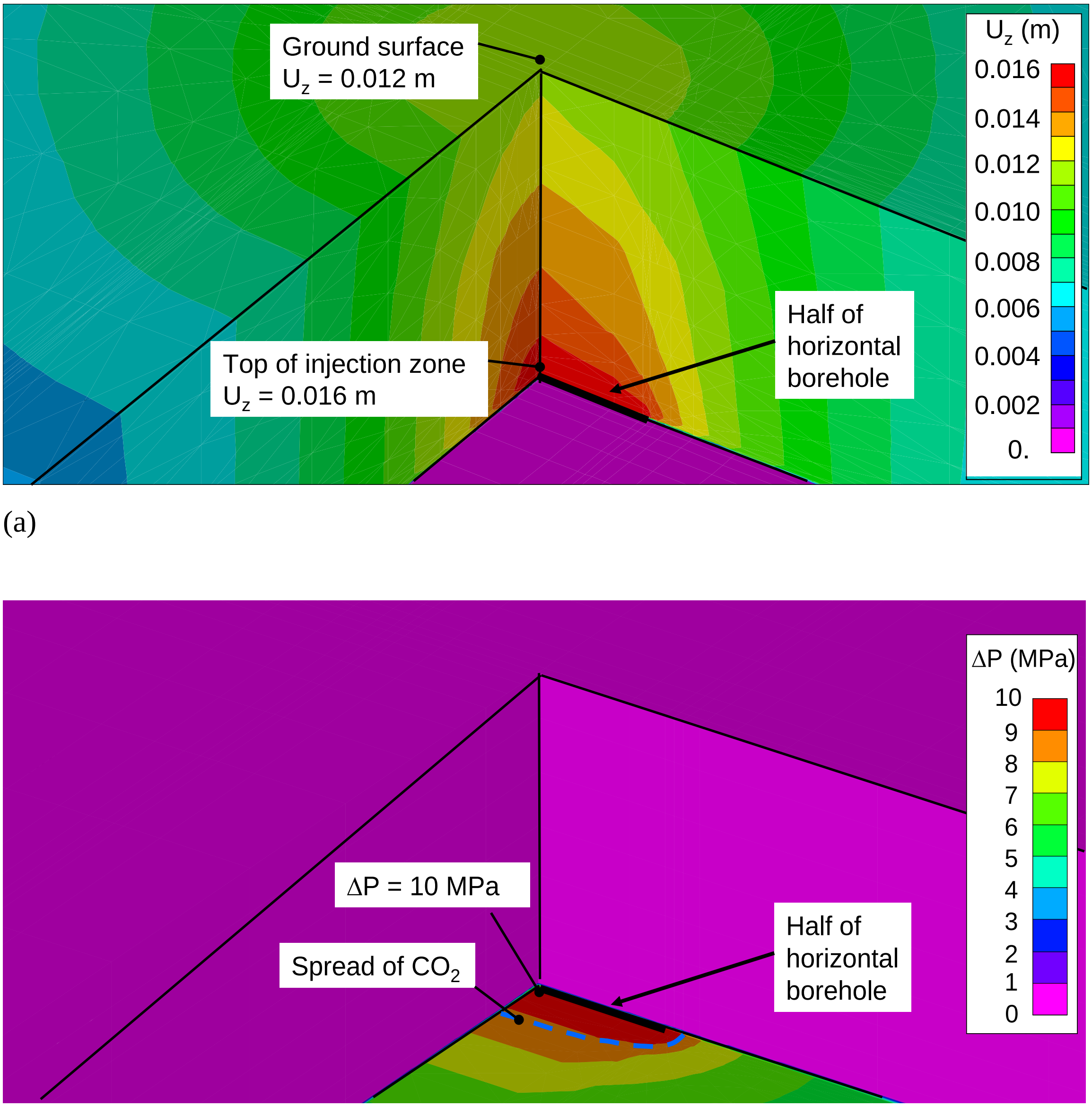
(b)

Figure 2.



KB503
KB502
KB501
5 km
[mm/yr]
FLAC3D
Geomechanical Simulator
TOUGH2
Multiphase Flow
Simulator
Cretaceous
sand/mudstones
(0-900 m)
Carboniferous
mudstones
(900-1800 m)
C10.2 sandstone
(1800-1820 m)
Base (D70)
(below 1820 m)
4 km
10 km
10 km

Figure 3.


Ground surface
U_z = 0.012 m
Top of injection zone
U_z = 0.016 m
Half of horizontal borehole
U_z (m)
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.

(a)

(b)_

ΔP = 10 MPa
Spread of CO_2
Half of horizontal borehole
ΔP (MPa)
10
9
8
7
6
5
4
3
2
1
0

Figure 4.

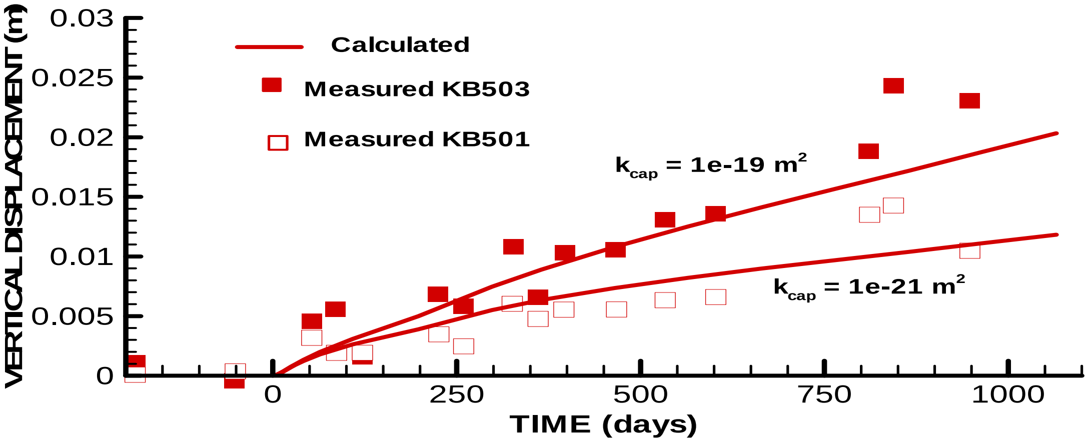
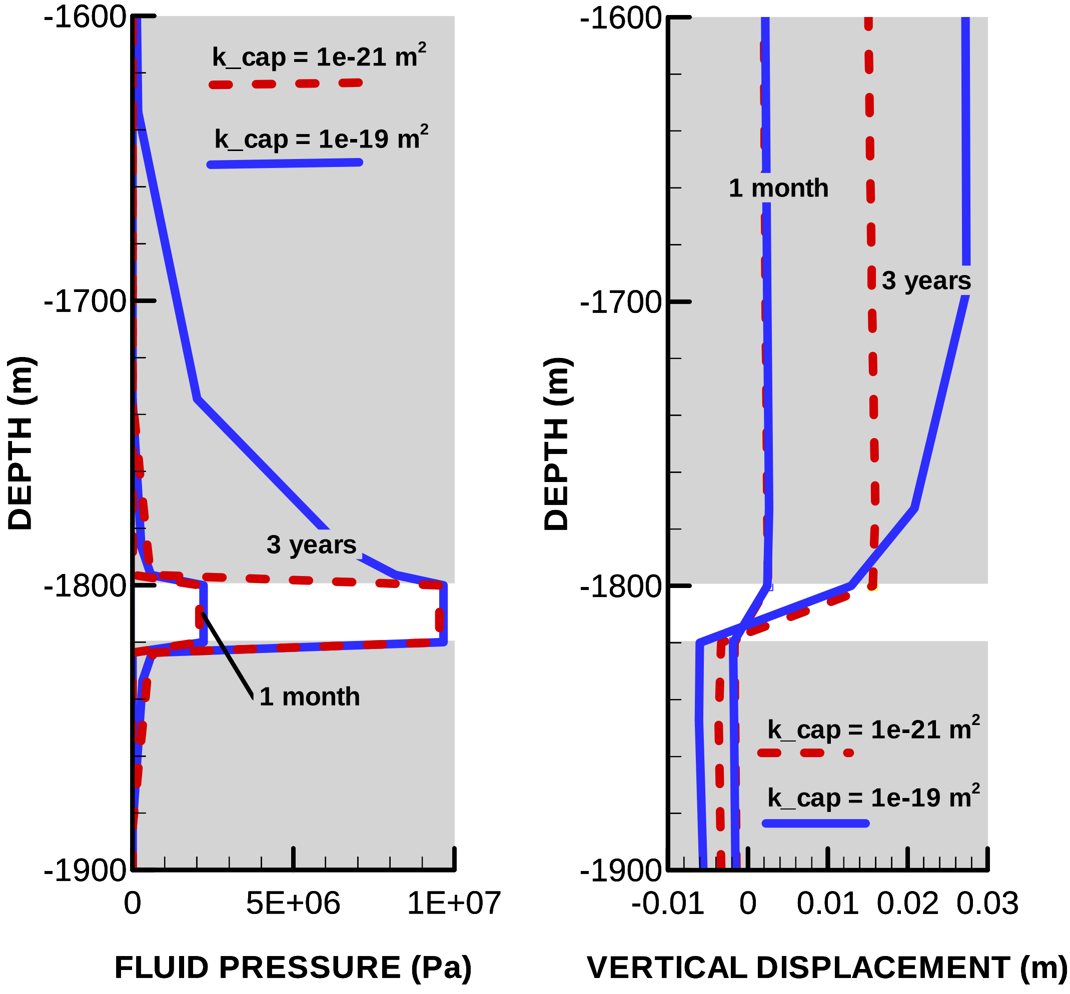

VERTICAL DISPLACEMENT (m)
0.03
0.025
0.02
0.015
0.01
0.005
0
Calculated
Measured KB503
Measured KB501
k_{cap} = 1e-19 m^2
k_{cap} = 1e-21 m^2
0
250
500
750
1000
TIME (days)

Figure 5.



-1600
-1700
-1800
-1900
DEPTH (m)
0
5E+06
1E+07
FLUID PRESSURE (Pa)
k_cap = 1e-21 m2
k_cap = 1e-19 m2
3 years
1 month
-0.01
0
0.01
0.02
0.03
VERTICAL DISPLACEMENT (m)

(a) (b)

Figure 6.

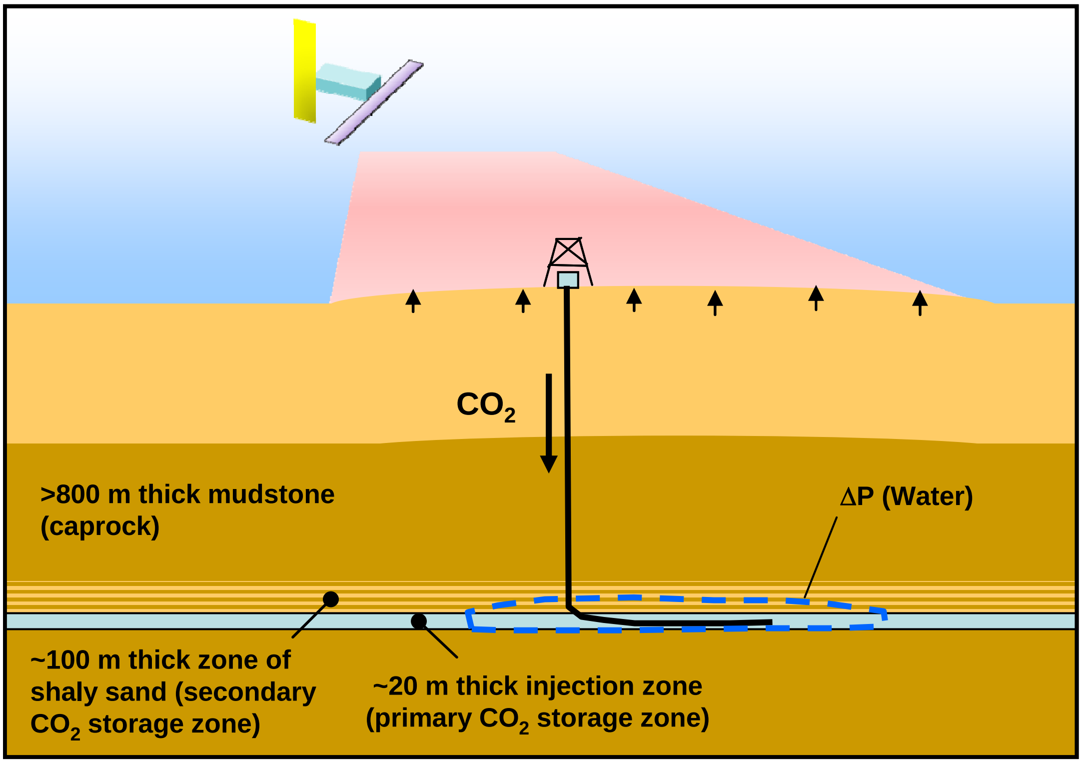

CO2
>800 m thick mudstone
(caprock)
ΔP (Water)
~100 m thick zone of
shaly sand (secondary
CO2 storage zone)
~20 m thick injection zone
(primary CO2 storage zone)

Figure 7.