Geomechanical behavior of the reservoir and caprock system at the In Salah CO₂ storage project

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Almost 4 million metric tons of CO₂ were injected at the In Salah CO₂ storage site between 2004 and 2011. Storage integrity at the site is provided by a 950-m-thick caprock that sits above the injection interval. This caprock consists of a number of low-permeability units that work together to limit vertical fluid migration. These are grouped into main caprock units, providing the primary seal, and lower caprock units, providing an additional buffer and some secondary storage capacity. Monitoring observations at the site indirectly suggest that pressure, and probably CO₂, have migrated upward into the lower portion of the caprock. Although there are no indications that the overall storage integrity has been compromised, these observations raise interesting questions about the geomechanical behavior of the system. Several hypotheses have been put forward to explain the measured pressure, seismic, and surface deformation behavior. These include fault leakage, flow through preexisting fractures, and the possibility that injection pressures induced hydraulic fractures. This work evaluates these hypotheses in light of the available data. We suggest that the simplest and most likely explanation for the observations is that a portion of the lower caprock was hydrofractured, although interaction with preexisting fractures may have played a significant role. There are no indications, however, that the overall storage complex has been compromised, and several independent data sets demonstrate that CO₂ is contained in the confinement zone.

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In Salah is an industrial-scale carbon capture and storage project located in central Algeria. Between 2004 and 2011, 3.8 million metric tons of CO₂ were injected into an anticlinal structure at ~1,800 m depth. Storage integrity at the site is provided by a massive, 950-m-thick caprock that sits above the injection interval (Fig. 1). It consists of a number of low-permeability units that work together to limit vertical fluid migration. These are grouped into main caprock units, providing the primary seal, and lower caprock units, providing an additional buffer and some secondary storage capacity.

In June 2011, injection operations halted at the site to allow reevaluation of the injection strategy (1). At the time, several monitoring observations suggested that pressure, and probably CO₂, had migrated vertically into the lower portion of the caprock. Although there are no indications that overall storage integrity has been compromised, these observations raise interesting questions about the geomechanical behavior of the reservoir and lower caprock system.

Several hypotheses have been put forward by various groups to explain these observations. These include fault leakage, flow through preexisting fractures, or the possibility that injection pressures hydraulically fractured a portion of the lower seal (2–13). In this work, we evaluate these hypotheses in light of the available data. We suggest that the most likely explanation for the observed behavior is that the lower caprock was hydrofractured, although interaction with preexisting fractures may have played a significant role. Previous studies by Bissell and colleagues (4) and Oye and colleagues (8) have shown that

injectivity and microseismic data show indications of fracturing behavior, at least in the reservoir and possibly in the overburden. Here, we use well data to constrain the state of stress in the reservoir and lower caprock, providing strong support for the hydrofracture hypothesis.

This work also highlights those monitoring and analysis methods that have been most useful for understanding the field behavior, as well as lessons learned and potential improvements. This perspective can guide future carbon storage projects.

Storage Reservoir

The storage project is colocated with a large natural gas operation. The field, Krechba, has an anticlinal structure with gas accumulation at the cap (Fig. 2). The produced gas has a high CO₂ content, which must be reduced before exporting gas to the European markets (14, 15). A surface separation facility is used to remove the CO₂, after which it is reinjected through three wells into the down-dip water limbs of the anticline. The three CO₂ injectors, denoted KB-501, KB-502, and KB-503, are long-reach horizontal wells that extend for several hundred meters through the ~20-m-thick reservoir.

Fig. 1 summarizes the major stratigraphic units at the site. The primary storage reservoir is a Carboniferous Tournasian sandstone unit (C10.2), which is overlain by a tight sandstone and siltstone unit (C10.3). Above this lies 900 m of Carboniferous Viséan mudstone (C20 units). The sealing layers below the C20.4 (the Hot Shale) are collectively referred to as the lower caprock, whereas those above are the main caprock. Above the main caprock is the Cretaceous Continental Intercalaire, a pan-Saharan aquifer and key water resource for the region (16, 17). Similar to other CO₂ storage projects, the caprock at In Salah is not a single sealing unit. Instead, a system of low-permeability barriers works together to create the confinement zone.

An advantage of colocating the injection and production wells is that data collection efforts could be leveraged by both operations

Significance

In Salah is one of the largest carbon capture and storage projects to date and has played a central role in demonstrating the feasibility of onshore sequestration of CO₂ in deep saline aquifers. The unique field experience at In Salah provides a valuable case study in managing commercial-scale CO₂ injections. In particular, the current work highlights the importance of geomechanics and integrated monitoring in understanding field behavior and managing storage risk.

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Fig. 1. Stratigraphic column with interval depths at well KB-502. Depth is given as meters of true vertical depth below the rotary table (m TVD brt) of the drilling rig, a common elevation datum in the oil and gas industry.

(3). Available data include well logs, leak-off and formation integrity tests, core measurements, 3D and time-lapse seismic, interferometric synthetic aperture radar (InSAR) monitoring of surface deformations, water quality monitoring of the shallow aquifer, and surface gas monitoring (1, 14, 18). Microseismic recording at the site is limited, however, and only comes from a single geophone string in a shallow well (KB-601). This recording was started in July 2009, well after injection operations had begun (8, 15).

Evidence of Lower Caprock Pressurization

The first interesting observation at Krechba was an earlier-than-expected breakthrough of CO₂ at well KB-5, an abandoned appraisal well 1.3 km to the northwest of KB-502. Injection at KB-502 began in April 2005, and gas reached KB-5 sometime between wellhead inspections in August 2006 and June 2007. Perfluorocarbon tracers injected at KB-502 in June 2007 were detected at KB-5 in March 2008, confirming the source of the CO₂ (19). The early breakthrough suggested that a highly permeable pathway connected the two wells.

The In Salah project was groundbreaking in its use of InSAR satellite data as a storage monitoring technology. A number of groups have demonstrated that surface deformation can be used to monitor pressure migration in the subsurface (2, 10, 20–22). Fig. 3 provides a snapshot of the measured surface deformations in March 2010. The measurements are in terms of the line-of-sight movement toward or away from the satellite (range change). Positive values indicate uplift. Significant uplift was observed above all injectors, but the deformation around KB-502 had an unusual, double-lobe pattern. A central trough is superimposed on the overall uplift, running perpendicular to the well. This trough is also parallel to the estimated present-day maximum horizontal stress (S_{Hmax} at ~135° Az). The operator was able to determine this northwest–southeast stress orientation on the basis of stress indicators in formation microimager (FMI) logs of several wells at the site. The authors have reviewed sections of these logs and concur with this interpretation. Additional stress indicators, such as focal mechanisms, are unavailable in the nearby region to further constrain S_{Hmax} orientation (23).

Vasco and colleagues (2) were the first to suggest that this unusual double-lobe pattern may be indicative of fluids migrating vertically into the lower caprock. As the reservoir was being pressurized, one would expect an approximately elliptical uplift pattern. The unusual pattern at KB-502 suggested that either the reservoir had a highly heterogeneous permeability structure that was compartmentalizing the pressure or, alternatively, pressure

was migrating into the caprock. It is known that a vertical, dilating crack in an elastic half space will create trough-like deformations at the surface (Fig. 4) (24). Vasco and coworkers suggested that a plausible explanation for the double-lobe pattern was that pressure was creating dilation along a narrow vertical zone. The resulting trough was then superimposed on the elliptical uplift associated with normal reservoir pressurization.

Although the other two injectors do not show the same double-lobe morphology, a subsequent two-component inversion analysis of the same InSAR data by Rucci and colleagues (10) suggests that surface deformations above all three injectors are consistent with vertical dilation zones in the lower caprock. The estimated dilation magnitudes at the other two injectors are smaller, however, so that the reservoir pressurization overwhelms any double-lobe signature at the surface.

Two 3D seismic surveys were shot at the site: a baseline survey in 1997 and a repeat survey over the northern portion of the field in 2009 (Fig. 2) (15, 18). Using the two surveys, the operator was able to identify time-lapse differences created by injection. It should be noted that the 2009 survey was much higher quality than the 1997 survey, creating processing and interpretation challenges (18). Their analysis revealed a change in the velocity structure above KB-502. In the 2009 data, a NW–SE trending feature crosses the well and extends into the lower caprock (Fig. 5). This feature was not visible in the 1997 survey, suggesting it is a seismic velocity anomaly arising from injection-induced changes. This anomaly and the InSAR trough are perfectly aligned and correlate well with the fast migration pathway from KB-502 to KB-5. A second anomaly was also found near KB-503, with the same orientation (Fig. 5). This anomaly is most visible to the southeast of the injector, near the gas/water contact, but the lineation intersects KB-503 and is parallel to the anomaly at KB-502. KB-501 was not covered by the 2009 survey and therefore could not be analyzed. This second anomaly suggests that at least two, and maybe all three, injectors are behaving similarly. Fig. S1 provides a vertical cross-section through the anomaly at KB-502. The exact vertical extent is difficult to determine, given limited seismic resolution, but it appears to be contained within roughly 200 m of the injection interval, below the Hot Shale.

It is unclear at this point if the seismic velocity changes are caused by excess pressure, CO₂ saturation, or mechanical effects.

Fig. 2. Map of the Krechba field. Numbered dots denote wellhead locations. Heavy lines indicate trajectories of horizontal wells.

Fig. 3. InSAR measured surface deformations as of March 2010.

At the time of the 2009 survey, KB-502 had been shut-in for approximately 2 years, and the reservoir pressure had nearly returned to background. This suggests that the velocity anomalies are more likely to be a saturation and/or mechanical effect.

These field observations all provide indirect indications that fluids may have migrated vertically, but none is definitive on the mechanism. A variety of hypotheses have therefore been put forward by various groups to explain these observations. Table 1 summarizes four plausible mechanisms, along with published studies relevant to each hypothesis. The remainder of this article examines these hypotheses in greater detail and discusses the supporting and contradictory evidence. Note that these mechanisms are not mutually exclusive (except for hypothesis 1), and more than one may have occurred at the site. For example, injection pressures could have hydrofractured the lower caprock by extending and coalescing preexisting fractures (combining hypotheses 3 and 4). Finally, much of the analysis to date has focused on vertical propagation upward. For many of the proposed mechanisms, however, there are physical grounds to expect that fluids could also migrate downward into the Devonian units. For example, Morris and coworkers (5) considered both downward and upward fluid migration on a preexisting fault. For obvious reasons, however, upward movement presents a greater concern with respect to storage integrity.

It should be emphasized that neither the InSAR nor seismic data suggest that the overall storage integrity has been compromised. In addition, if a significant flow path had formed through the 950 m of caprock, a noticeable drop in reservoir pressures should have been observed (9). This has not been the case. Finally, no water quality degradation has been observed at monitoring wells in the shallow aquifer (17).

Hypothesis 1: Reservoir-Only Behavior

The first hypothesis is that all monitoring observations are consistent with excess pressure and CO₂ saturation contained in the reservoir interval. That is, there has been no vertical migration of fluids into the caprock. As suggested by Vasco and colleagues (20), it is possible that the observed surface deformations above KB-502 could result from a heterogeneous permeability distribution in the reservoir interval alone. A low-permeability zone intersecting the injector and extending to the northwest could partition the reservoir pressurization into two zones, each responsible for one of the uplift lobes. Although inversion models including a vertical dilation zone provide a better fit to the data, one can conclude that InSAR data alone are ambiguous on whether fluid migration has been contained in the reservoir.

The observed velocity anomalies, however, make hypothesis 1 less plausible. The anomalies require a mechanism to change the velocity structure of the lower caprock (i.e., pressure, saturation, and/or mechanical changes). The reservoir-only hypothesis implies the only significant changes to the caprock that have occurred are far-field geomechanical deformations. The diffuse nature of such deformations would not explain the narrow tabular zones that are observed. We therefore conclude that hypothesis 1 has a low probability. Although it cannot definitively be excluded, it does not provide a simple explanation for the similarity of the InSAR and seismic anomalies and requires a complete discounting of the seismic evidence.

Hypothesis 2: Fault Leakage

In response to indications of possible caprock damage around KB-502, much of the initial investigation focused on the potential for leakage through preexisting faults at the site (5–7). This work was motivated by a fault interpretation of the 1997 seismic survey, which suggested a fault or lineation intersecting the horizontal leg of KB-502 (Fig. 6). The strike of this lineation (120° Az) is rotated $\sim 15^\circ$ with respect to the estimated maximum horizontal stress. A later interpretation of the higher-quality 2009 survey did not pick out this same lineation. The inferred stress regime for the site is strike-slip, with the vertical stress being the intermediate stress (3). Faults with a similar orientation to the “phantom” fault from the 1997 survey could potentially be reactivated by injection pressure.

The fault interpretation was performed by the operator and is briefly described in ref. 18. It is based on reflector offsets in the seismic volume, supplemented with attribute analysis and other methods to help identify smaller features. The 20-m-thick reservoir (C10.2) is never fully offset, and all identified faults were close to the limit of resolution. The same faults are not visible at the C20.1 horizon, ~40 m above the reservoir. No substantial faults are observed in the caprock, suggesting that any faulting in the seals is minor and below seismic resolution. An important caveat is that the caprock in general contains fewer reflectors, making identification more challenging.

Drilling records for KB-502 suggest that the reservoir interval contains unobserved faults. While drilling the horizontal well section through the C10.2, cuttings and logging while drilling revealed that the well suddenly reentered the C10.3 unit. The interpretation was that the well had passed through a vertically

Table 1. Four plausible hypotheses to explain available observations

Hypothesis	References*
1. Reservoir-only behavior: Observations are consistent with excess pressure and CO ₂ contained in the reservoir	12, 19, 20
2. Fault leakage: The reservoir intersects one or more faults, providing a vertical migration pathway	1–3, 5–7, 9–12, 18–20
3. Hydrofracture: Injection has created new fracture pathways, through tensile hydrofracture	1, 2, 4, 7–11, 13, 20
4. Preexisting fractures: Preexisting fractures are intrinsically permeable, or reactivated by pressure	1–4, 7–13, 18–20

*Published studies by various groups relevant to each mechanism.

Fig. 4. Plausible mechanism to explain double-lobe deformation.

offset fault. The well was then deviated downward to once again enter the C10.2 a few hundred meters further on. This encounter occurred well away from the observed linear feature, however.

There is no indication of large-scale shear deformations in InSAR. Such deformations would likely induce asymmetric uplift patterns because of opposing lateral displacements on either side of a strike-slipping fault. Only minor asymmetry is observed, all of which can be attributed to the nonvertical look angle of the satellite. The data, rather, indicate a tensile opening mode, which could correspond to a fault zone dilating as pressurization occurs.

It is possible that the reservoir intersects one or more undetected faults that can provide a vertical leakage pathway. The consistency of observations at each injector, however, makes hypothesis 2 problematic. Seismic velocity anomalies are observed at two injectors, and InSAR data suggest all may have tensile opening in the overburden (10). The fault hypothesis would imply that all three have intersected (by chance) leaking faults that are aligned with the in situ stress field. The interpreted faults display a number of orientations but show no preferential alignment with the present-day stress field. Therefore, although still plausible, we conclude that the evidence in support of hypothesis 2 is weaker than for other explanations.

Hypothesis 3: Hydrofracture

The third possibility we examine is that injection pressures caused hydrofracturing in the reservoir and lower caprock units. Leak-off tests and formation integrity tests were performed during the drilling of all wells at the site. A step-rate test was also performed in well KB-9. These well tests can be used to estimate the minimum principal stress and fracture pressure of the formation. A detailed introduction to the test procedures and their interpretation can be found in ref. 25. Compiled test data for production wells 9–14 and injection wells 501–503 are summarized in Fig. 7. Well locations are marked in Fig. 2. To compare tests performed at different depths, all results are presented in terms of equivalent mud weight (EMW); that is, the pressure gradient, rather than the pressure itself. Hydrostatic conditions correspond to an EMW = 1.0 specific gravity (sg) = 0.1 bar/m. Furthermore, because stratigraphic contacts in different wells occur at different depths because of the anticlinal structure, we have converted the vertical depth to a height above the C10.2 interval at the given well. This allows for an easier visual comparison of Viséan and Tournaisian data points. Layer thicknesses are marked using depths from KB-502. There is some variation in layer thicknesses across the site. During drilling, significant wellbore stability issues were often encountered near the base of the C20 units, requiring an increase in mud weight. This “unstable zone” is inferred to be a layer of high tectonic stress.

The most direct measurement of fracturing behavior in the C10.2 interval comes from the step-rate test in KB-9. The raw pressure and flow rate data measured during this test are provided in Fig. S2. Summary results are included in Fig. 7 as an error bar symbol. The lowest bracket is the measured instantaneous shut-in

pressure, the middle is the fracture propagation pressure, and the highest is the fracture initiation pressure. The leak-off pressure is approximately the same as the instantaneous shut-in pressure. Hollow symbols denote formation integrity test data; that is, the formation could sustain the applied pressure without leak-off. Filled symbols are tests in which leak-off was observed. There are no leak-off tests for the C10.3 interval. There is also one leak-off test in the C15 interval (filled triangle), a mudstone/limestone unit encountered over part of the field.

It should be emphasized that estimating fracture pressures from well measurements is always difficult, given limited and scattered data. These tests also have considerable uncertainties. They are influenced by drilling performance, wellbore damage, and near-wellbore fractures. They only measure behavior in a small region near the wellbore, and only the step-rate test actually exceeds the fracture initiation pressure. The tests are also performed with drilling mud, which behaves differently from low-viscosity, cold CO₂. Therefore, extrapolating these measurements to kilometer-scale behavior should be done cautiously. They can only be used as a general insight into minimum principal stress and fracturing behavior.

From the data, there appears to be a consistent EMW = 1.35 sg leak-off trend through most of the Viséan C20 caprock. In the unstable zone, there is a noticeable jump, however, to at least 1.55 sg. In the C10.3, only formation integrity test measurements are available, but one could infer a leak-off value of at least 1.6 sg. For C10.2, there is one step-rate test measurement with leak-off observed at 1.25 sg.

The data suggest that fractures could likely be initiated and propagated in sandstone and mudstone units at an EMW somewhere in the range of 1.35–1.70 sg, although the uncertainties mentioned earlier should be kept in mind. For the interval depths at KB-502, this corresponds to a pressure range of 239–301 bar at the top of the C10.2 and 237–298 bar at the top of the C10.3. Fig. 8 shows the estimated bottom-hole pressure (BHP) for KB-502. Daily-averaged values are presented for clarity, as the averaging smooths out hourly fluctuations. BHP was not measured directly, and all BHP measurements are

Fig. 5. Two-way time image of the C20.1 top (~40 m above the injection unit) in the 2009 3D seismic volume. Red-to-blue color indicates shallower-to-deeper depth to the anticlinal horizon. Northwest-southeast trending features indicated by black arrows were not seen in the 1997 survey and are interpreted to be seismic velocity anomalies correlated with injection. Image courtesy In Salah Joint Industry Project.

Fig. 8. Time history of estimated BHP at KB-502.

Fractures striking parallel to the maximum horizontal stress would likely be reopened when the fluid pressure exceeded the minimum horizontal stress. Furthermore, there are preexisting fracture orientations that are well-oriented for shear. These fractures could be reactivated at injection pressures lower than the minimum horizontal stress, depending on the cementation and frictional properties of the fractures. In fact, the low leak-off pressure observations at many places in the caprock could be caused by shear along preexisting fractures, rather than tensile initiation of new fractures in intact rock.

Unfortunately, no data are available on the strength and frictional properties of fractures at the site. Nevertheless, it seems likely that peak injection pressures are sufficient to reactivate any existing fractures in both tensile and shear modes. These fractures could also propagate and coalesce through hydrofracture or hydroshearing, improving the connectivity of the initial fracture network. The role that preexisting fractures play in the permeability behavior of the caprock remains a large and important uncertainty.

Summary

In this work, we have explored possible mechanisms to explain observed InSAR deformations, seismic velocity anomalies, and injection behavior. We argue that the evidence favors the hypothesis that injection pressures hydrofractured the reservoir and lower caprock. Vertical hydrofractures provide a simple explanation for the observed narrow, linear features running perpendicular to the minimum in situ stress. An analysis of leak-off and formation integrity test data supports the notion that

injection pressures exceeded the fracture pressures for the reservoir and lower caprock units. The timing of the injection pressure increase at KB-502 correlates well with the appearance of the double-lobe in InSAR.

High pressures could also reactivate and coalesce preexisting fracture pathways (a combination of hypotheses 3 and 4), and their role should not be discounted. The evidence in favor of fluid migration from the reservoir along faults is weak, but there are small faults present at the site that could serve as partial migration pathways (7).

In Salah benefitted greatly from the diversity of monitoring techniques applied at the site. Individually, each of the data sets contains ambiguities that make interpretation difficult. Together, however, a clearer picture begins to form. The field experience also highlights the benefits of careful site selection. The 950-m caprock provides a number of thick, resilient seals. As a result, the formation can sustain a breakdown of lower caprock units without compromising the overall storage integrity. This robustness should be a major priority during site selection for future carbon capture and storage projects. At Krechba, robustness is achieved through the massive nature of the seals, but other sites could achieve a similar level of resilience by relying on multiple, thinner seals interleaved with permeable thief zones.

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