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# A Full Field Simulation of the In Salah Gas Production and $CO_2$ Storage Project Using a Coupled Geo-mechanical and Thermal Fluid Flow Simulator.

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**Abstract**

We report results from a full field simulation model of the combined production and injection reservoirs, extending from a depth of 3.5 km to ground level, and with a lateral, x and y, extent of approximately 50 km. The model couples geomechanical calculations to fluid flow with an energy transport equation. It simulates two-phase immiscible flow with four components ($CH_4$, $CO_2$, NaCl and $H_2O$) in the gas and aqueous phases. $CO_2$ may dissolve into the aqueous phase. Fractures are modelled explicitly in the grid.



*In Salah; $CO_2$ storage; simulation; geomechanics; thermal*

## 1. Introduction

Since 1 August 2004, the In Salah Gas project in Algeria has injected about 3 million tonnes of $CO_2$ into a 20m thick Carboniferous interval at a depth of about 2 km in a saline aquifer. Simultaneously, hydrocarbon gas has been produced, starting on 18th July 2004, from the same interval in a reservoir adjacent to the $CO_2$ injection site [1].

Interferometric Synthetic Aperture Radar (InSAR) satellite surveillance data shows surface uplift around the injection site, and subsidence at the production site, of the order of a few millimetres per year. The uplift is elongated in a north-westerly direction at each of the injection wells [2, 3].

The purpose of this study was to assemble a coherent model, consistent with all observations, and predict future data to aid monitoring and risk assessment. This was not done using a single piece of software but, rather, an interlinked series of products [4]. It is not just a plume model.

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The work is organized by following the $CO_2$ from the injection wellheads, down the wells and through the completions and into the storage interval. At each stage of the workflow the modelling parameters are uncertain and this feeds errors into subsequent stages. The result is a set of models, each of which is a possible interpretation of the data. There is no single correct model but we can specify our Most Likely case.

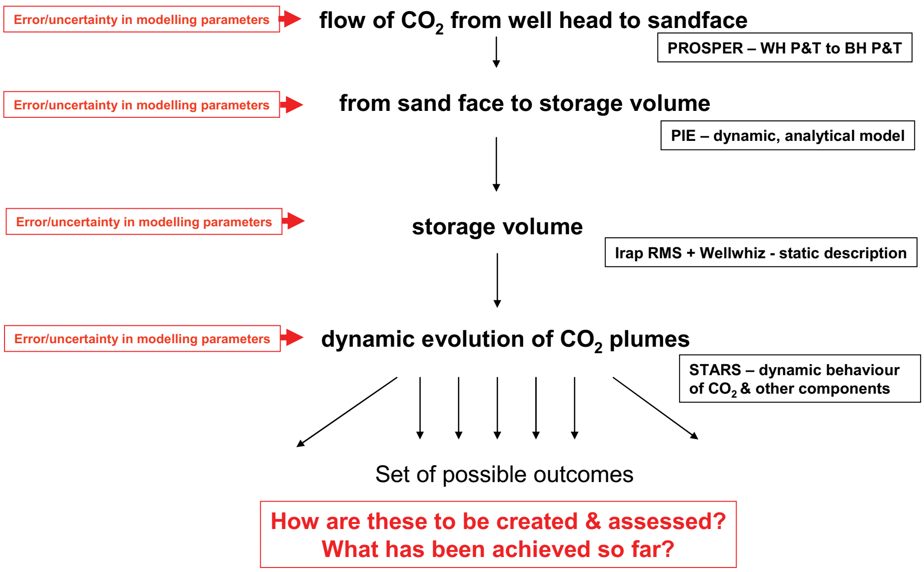



**Figure 1: Workflow**

In this instance we have mapped this workflow to the following software; Prosper, PIE, Irap RMS, Wellwhiz and STARS

**2. Modelling $CO_2$ from Wellhead to Bottom Hole**

Wellhead (WH) pressures, temperatures and flow rates were taken from field data for each of the injection wells (KB-501, -502 and -503) and converted to bottom hole (BH@1330 m TVD ss) values using Prosper. Different correlations gave similar results for the estimated BH flowing pressures (FBHP) and temperatures (FBHT).

Three shut-in pressure measurements were available, one for each of the injection wells and these were used to calibrate the Prosper models.

The resulting estimates of BH flowing pressures are plotted in the figure 2, together with an estimate of the fracturing pressure ($P_{frac}$) at 1330 m TVD ss. Figure 3 plots the estimated FBHT. It is emphasized that there is uncertainty in the estimate of $P_{frac}$ and in the estimated FBHP and FBHT data. No estimate of the errors in the data is given. Fractures at the injection interval were intended to aid injectivity in the original field development plan.

In summary, we see that in all the injection wells the FBHP may exceed $P_{frac}$ (at the injection interval, not in the caprock) at some times and that the temperature of the $CO_2$ as it flows into the formation is about 40 $^oC$ less than the initial formation temperature. Simulations with the STARS model showed that the cooling effect of the injected $CO_2$ was limited to a decrease of ~ 8 $^oC$ over a period of six months from the start of injection at KB-502 over a range of about 5-10 metres from the wellbore. Similar results have been obtained by Rutqvist et al [5]. Using an expression from Perkins and Gonzalez [6], we estimate that the cooling of the formation may reduce $P_{frac}$ by 15-50 bars from its initial value of ~286 bara @ 1330 m TVD ss, see section 3.

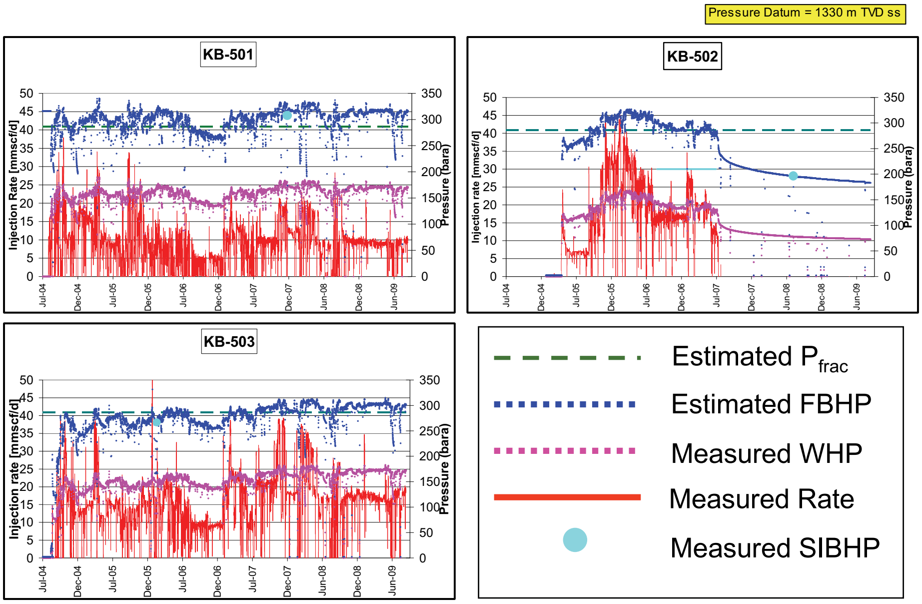
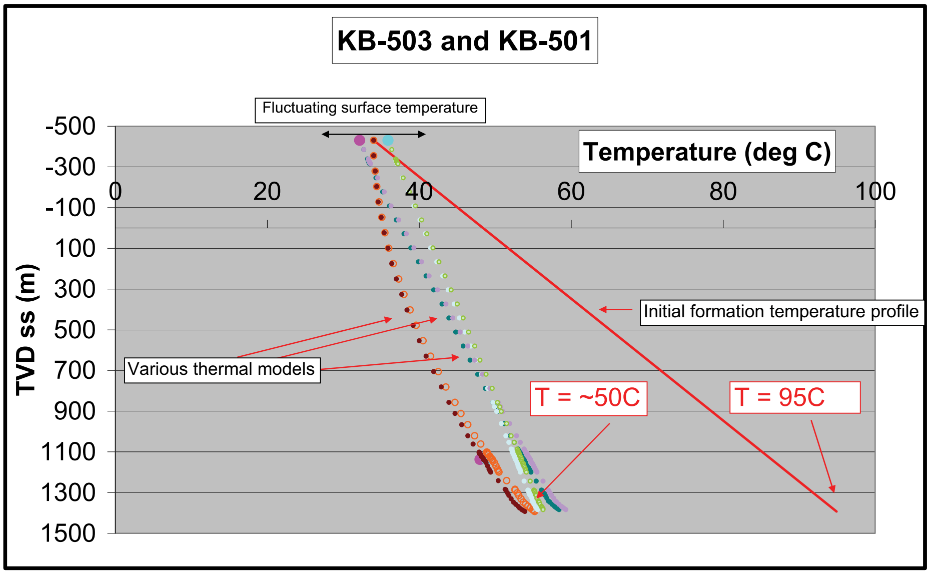



**Figure 2: Estimates of FBHP's & Fracturing Pressure**




**Initial temperature difference between injected $CO_2$ & formation is ~ 40 °C for average injection rates.**

**Figure 3: Estimated $CO_2$ Flowing Temperature vs Depth Profile**

Next we turn to the behaviour of the BH injectivity index (II) with changes in FBHP. The injectivity index is a measure of how easily fluid can be injected into the formation. Here, it is defined as the volume of $CO_2$ injected per day, evaluated at BHP and BHT to remove the effects of fluid compressibility, divided by the pressure drop from the wellbore into the reservoir.

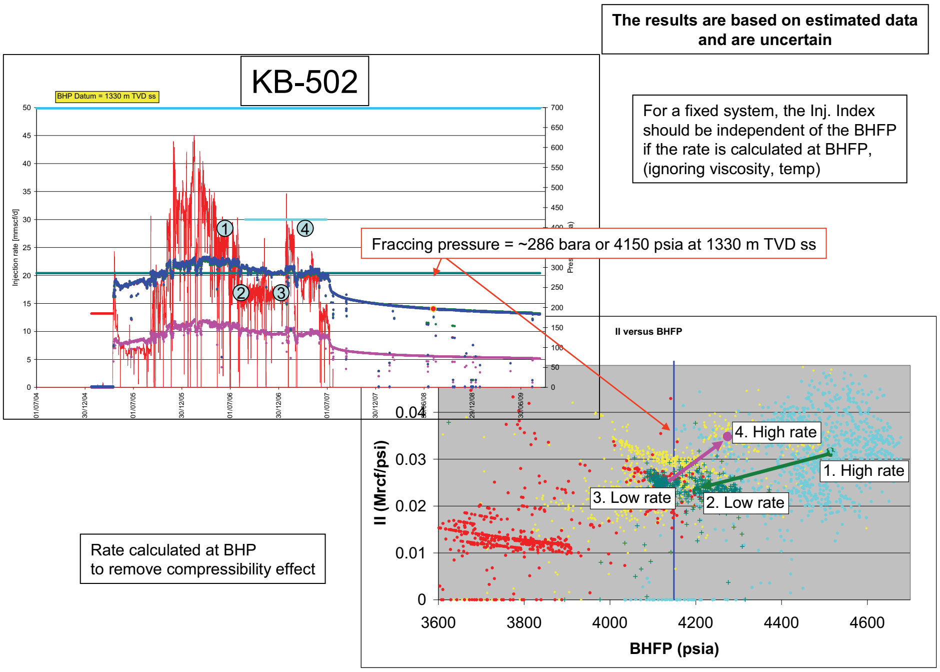



**Figure 4: Injectivity Index versus FBHP**

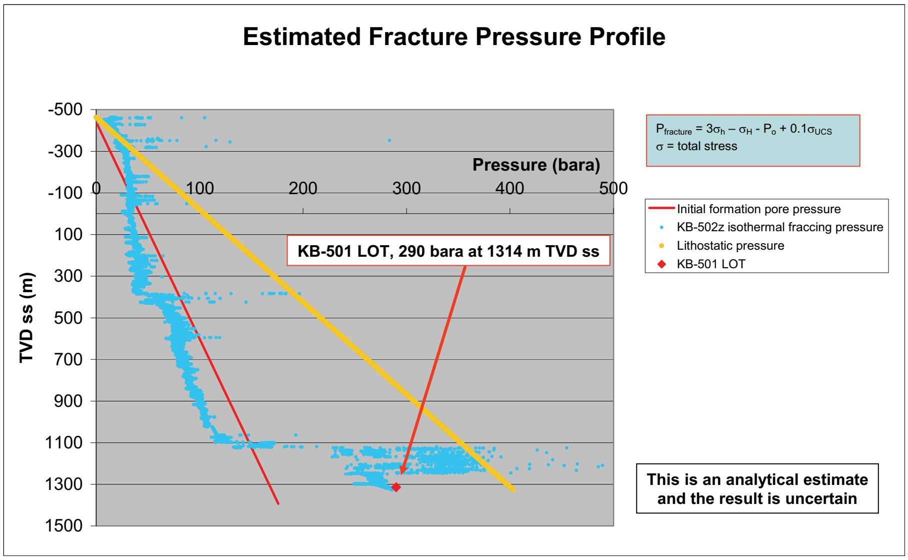
The figure has four rates marked, labelled 1, 2, 3 and 4. The rate falls from points 1 to 2 and increases from points 3 to 4. As the rate falls the II decreases and, as it rises, the II increases. This indicates that the wellbore to reservoir coupling is changing and could be interpreted as an event where a fracture closes (II decreasing) and opens (II increasing). Similar effects were seen in KB-501.

A PIE well test analysis of the KB-502 pressure data had two interpretations where, in both cases, a low permeability matrix (~1mD) had been penetrated by a high permeability structure. This result was based on estimated FBHP's at a low frequency (1-2 per day) and is considered to be very uncertain. In summary, there is evidence that the injection wells, particularly KB-502, are fractured, at least locally (< 100m from well). History matching will show that the fractures at KB-501 and -502 may extend $10^2$ – $10^3$ metres horizontally and ~$10^2$ metres vertically at KB-502.

## 3. The Geomechanical Model

Tests were performed on 14 samples from the Krechba site in the hard rock just above the main injection interval [7]. The unconfined compressive strength (UCS), Young's modulus (E) and Poisson's ratio ($P_R$) in the direction perpendicular to the bedding were measured. The UCS ranged from 48 - 184 MPa, E from 12 - 47 GPa and $P_R$ from 0.09 - 0.33

Data from a study of the Krechba well logs by Darling [8] and a geomechanical study [9] were used to estimate the vertical fracturing pressure ($P_{frac}$) which is plotted in figure 5 and to create a 3D geomechanical model for input into STARS. Note the stronger rock immediately above the C10.2 injection interval and that the estimated fracturing pressure is consistent with the result form the KB-501 injection well leak-off test (LOT). The log-derived data agreed well with the laboratory measured data. Having calculated values for E and $P_R$, we adjusted the vertical intervals in the simulation grid to best represent the variations in this data. This required 63 vertical layers in the model from the ground surface to 3.5 km below ground level i.e. approximately 1.5 km below the storage interval. It was not possible to calibrate the log-derived data for the softer overburden rocks because there were no samples. Here, we history matched the geomechanical model to the measured surface deformation by adjusting E. The log-derived E was multiplied by a single scalar in the range 0.4 – 0.65 over the entire vertical depth of the model.




**Perkins & Gonzalez' (1984) expression ⟶ ~0.18MPa/deg C reduction for storage interval [6]**

**Figure 5: Estimated Fracture Pressure *vs.* Depth**

## 4. InSAR Data

Vasco *et al* inferred a fault/fracture at KB-502 [3] using this data and details of the solution are shown in figure 6.

**Vasco's solution:**
KB-502 Fault/fracture position and dimensions:
Azimuth = 319º, dip = 89º, Depth = 1800 m bgl, Height = ~100m ± 80m; continues down into underburden
Length = 5-7 km passing through KB-502 (~ 1km SE of KB-502 & 4-5 km NW of KB502)

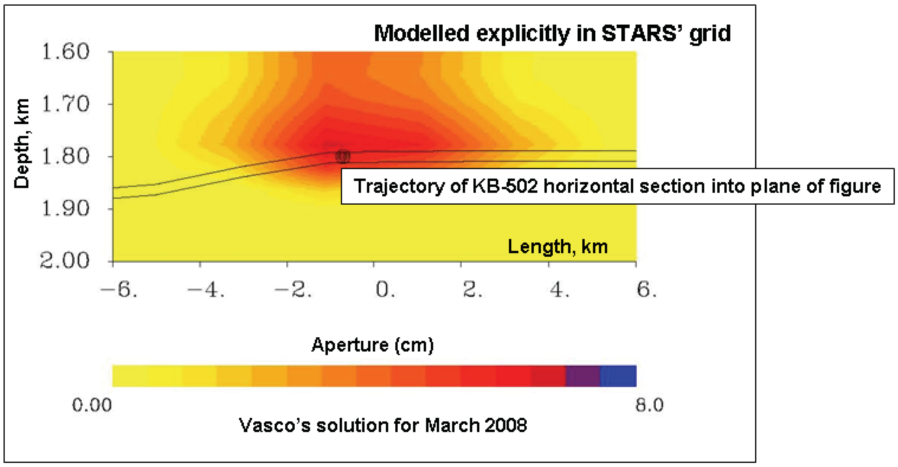



**Figure 6: Vasco Fault/Fracture Input into STARS Model (vertical x-z slice)**

### 5. Simulation Model and Some Results

The geological model was created with Irap RMS. During the project five generations of grid were created. The current grid is 50x40 km areally and 3.5 km deep, from the ground surface. The main surfaces were extrapolated from those interpreted from a 1997 seismic survey. The prorosity and permeability arrays were generated using an assumed statistical model conditioned to core plug measurements. The number of gridcells is 1.6 million (149x171x63) with a minimum $\Delta x$ = 0.3m and a minimum $\Delta z$ = 1m, at KB-502. A hypothetical set of fractures, based on Vascos's inversion of satellite data, has been explicitly represented in the grid using Wellwhiz at KB-502. A 3D geomechanical finite element model is coupled to the flow simulation. Thermal effects are modelled using an energy transport equation. There are four components ($H_2O$, NaCl, $CO_2$ and $CH_4$). NaCl is used to weight the water and $CO_2$ can dissolve in the water. The simulation period is from 2004 to 3050.

The model was history matched to the injectors' estimated FBHP's, the shut-in BHP's and the InSAR measured surface deformation and the average reservoir pressures measured at the production wells. An earlier version of this model had been matched to the breakthrough of $CO_2$ at KB-5 (an appraisal well [10]) from KB-502, by introducing a fracture between the wells with a permeability of ~1 Darcy.

Figure 7 shows the history match of the injection wells to the FBHP's, the shut-in BHP's and compares the vertically averaged $CO_2$ saturation with the surface deformation measured on 28 August 2009. The horizontal permeabilities were strongly anisotropic with the greater permeability in the direction of the maximum horizontal stress. In addition, it was necessary to introduce time varying transmissibilities, parallel to the direction of the maximum horizontal stress, to mimic the opening and closing of vertical fractures (not required for KB-503). These remained within the injection interval at KB-501. This technique has been used by other groups [1, 11, 12].

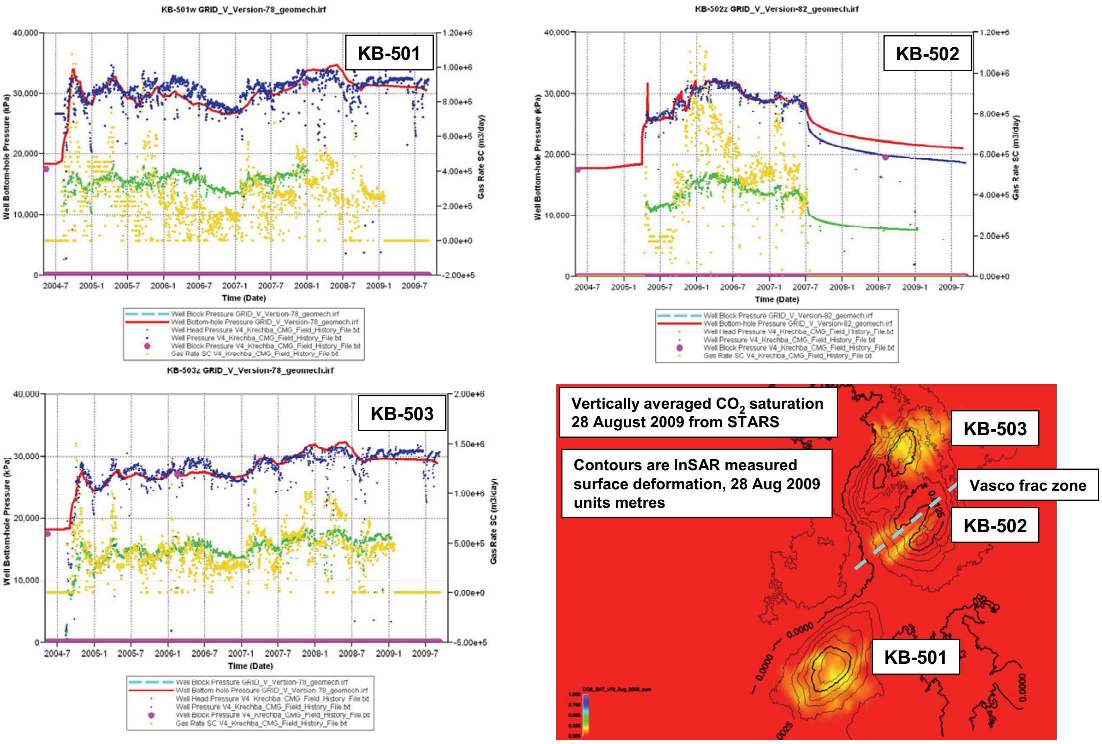



**Figure 7: History Match for Injection Wells**

Figure 8 shows the match to the surface deformation where the scalar multiplier for Young's modulus was 0.65. (The model shows greater deformation in the injection interval).

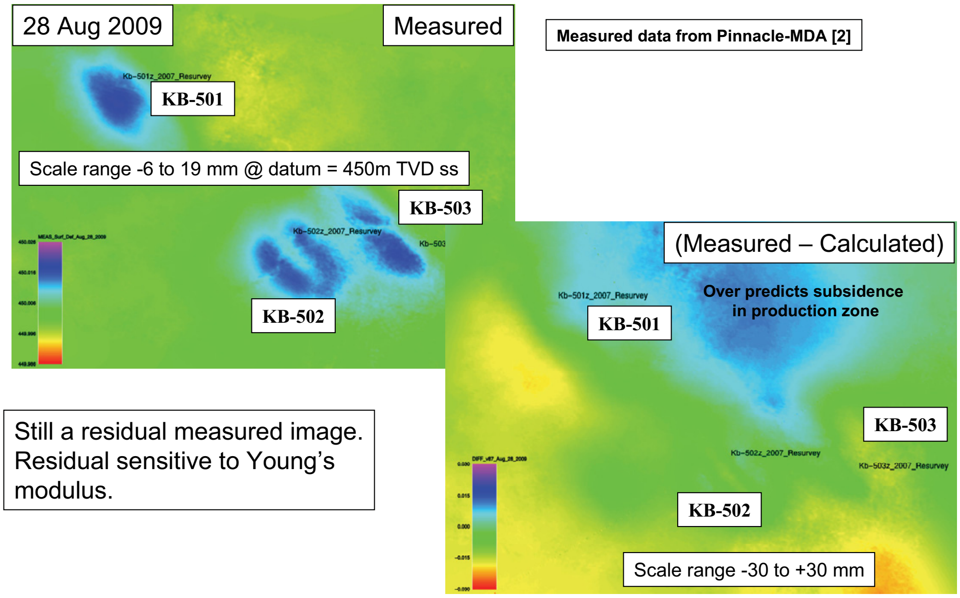



**Figure 8: STARS' model - Match to Surface deformation Aug 2009**

Figure 9 shows the results of a prediction run to 2100 based on the history matched model. A total of 17 million tonnes of $CO_2$ was injected between August 2004 and August 2029. This is our current Most Likely model.

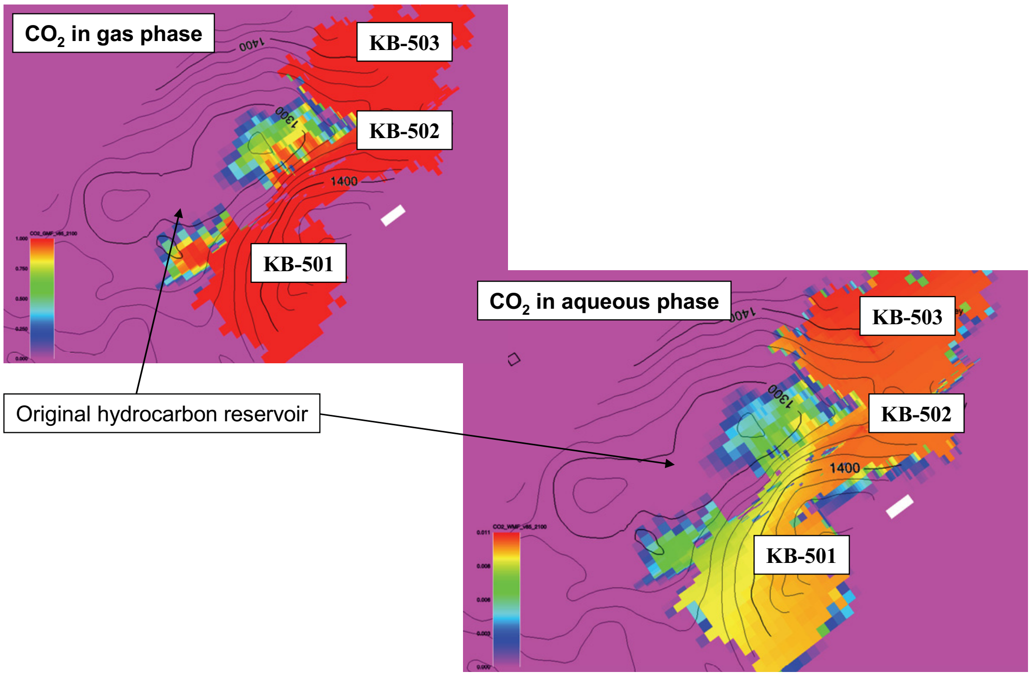



**Figure 9: STARS' Model – Prediction to 2100**

## 6. Conclusions

The behaviour of this storage system is determined by the rate at which it can initially accommodate the cool injected $CO_2$ as a consequence of its low permeability and porosity. The response of the system is to relieve the build-up in pressure by elastic deformation, creating the measured surface uplift, and by fracturing.

A static, time-averaged, geomeodel is unable to match the KB-501 and KB-502 estimated FBHP's.

Different combinations of matrix and fracture flow may match the FBHP's but fewer combinations also match the surface deformation caused by $CO_2$ injection.

The model described here is only one of a set of possible models but it is our current Most Likely case.

## Acknowledgments

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