MODELING OF THE CO_2 GEOLOGICAL STORAGE AT THE S3 SITE (SIM-SEQ COMPARATIVE PROJECT)

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ABSTRACT

The Sim-SEQ project coordinated by the Lawrence Berkeley National Laboratory (LBNL) aims at providing a comparative study of different conceptual models with respect to predicting the behavior of CO_2 geological storage operations conducted on a reservoir formation, while using the same database for site characterization. The S-3 site has been selected for conducting such a comparative study. All site characterization and operational data for the S-3 site are supplied by the Bureau of Economic Geology (BEG) at the University of Texas at Austin. The site is a depleted oil and gas field, located in the Mississippi Gulf Coast (United States), at which CO_2 injection started in November 2009.

Being one of the participating modeling teams, BRGM proposed to provide a complete assessment of the field by generating a 3D static earth geological model using the Petrel reservoir geomodeler, and by using an in-house toolbox to convert the 3D mesh of the static model into TOUGH2 and TOUGHREACT formats, before generating a multiphase flow simulation of the CO_2 injection. The geological model is constructed based on information provided by several well log data. Horizon surface is rebuilt, and fluvial sandstone-shale facies distribution is generated. Reservoir petrophysical properties are associated to each facies in agreement with the provided data (absolute and relative permeability and capillary pressure), as well as temperature and salinity. Hydrostatic pressure and temperature gradient is recalculated before the simulation of the CO_2 injection. Calibration of the model is performed by comparing results from the simulated scenario with observation-well data provided in the project.

The geochemistry of the water and the mineralogy description of the rock will serve as perspectives in evaluating the fluid-rock-interaction evolution of the system for the tens-of-years injection and post-injection period. This paper provides details on the methodology and preliminary results regarding the static geological model and dynamic flow simulation.

INTRODUCTION

The aim of the Sim-SEQ project is to compare modeling prediction studies from different teams, using data based on the observations made during the CO_2 geological storage performed at the S-3 site, a site modeled from a depleted oil and gas field located in the Mississippi Gulf Coast (United States)—see Mukhopadhyay et al. (2012). All data are supplied by the Bureau of Economic Geology.

In this paper, we present the development of a 3D static geological model of the S3 site using the Petrel geomodeler (©Schlumberger) and a multiphase flow modeling of CO_2 injection using TOUGH2-MP (©LBNL) and the previous 3D model.

GEOLOGICAL MODELING

A structural 3D model of the S3 site was developed with Petrel software (© Schlumberger). The modeling process consists of creating surfaces, creating horizons and zones, upscaling well data, and layering, in order to generate a 2000×2000×80 ft grid with 200×200×8 cells as defined in the Sim-SEQ project.

Construction of the structural 3D model

The data used to construct the 3D model is provided by LBNL (Sim-SEQ website at https://gs3.pnl.gov/simseq/wiki/index.php/Sim-SEQ_Home) and consist of one ASCII file with coordinates in XYZ format describing the top of the reservoir as well as the three wells (SS31F1, SS31F2 and SS31F3) information (wellhead

location and well tops), available well logs and core analysis.

The first step is to compute surfaces using the XYZ points. A convergent interpolation algorithm is used with an X/Y increment of 50 ft in order to fit (as close as possible) with input data. This "top reservoir" surface is used to construct the "base reservoir" surface by shifting the top reservoir 80 ft deeper. After analysis of gamma ray (GR) curves at wells SS31F2 and SS31F3, the well tops Top/L Tusc. D Sand are moved slightly, and the top reservoir surface is re-interpolated with the make/edit surface process of Petrel, including a well adjustment in order to fit with the well tops. The same process is applied to the base reservoir surface (Fig. 1).

Based on a GR curve analysis, we identify (within the reservoir) two main sand bodies of 11–12 m delimited by a 1 m thick shaly layer. The well tops corresponding to the top and base of each sand body are chosen, and the corresponding surfaces are interpolated using the top reservoir surface shifted and fitted to the well tops (Figure 1).

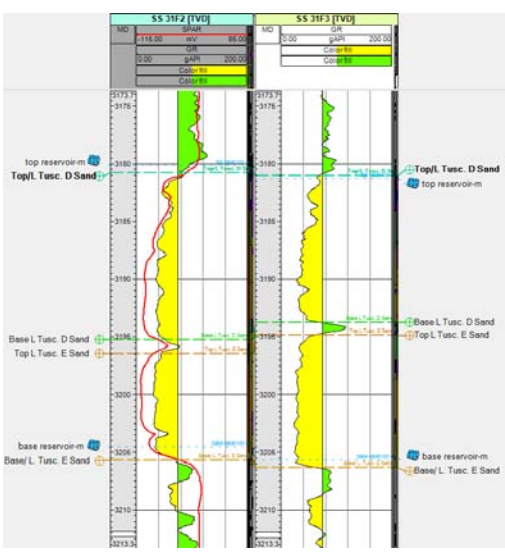

Figure 1. GR curve (green when GR>75 API and yellow when GR<75 API) of wells SS31F2 and SS31F3 used to locate well tops Top D Sand (corresponding to the top reservoir), Base D Sand, Top E Sand and base E sand (base of the reservoir). Red line on SS31F2 well correspond to the sonic curve.

A simple grid is generated with the geometry defined by the Sim-SEQ project. As four surfaces are incorporated in the model and transformed into horizons, three zones are automatically created between these horizons (Figure 2). The zones are in turn divided into layers as follows: D sand (zone 1) with four layers, Shaly bed (zone 2) with one layer and E sand (zone 3) with three layers (Figure 2).

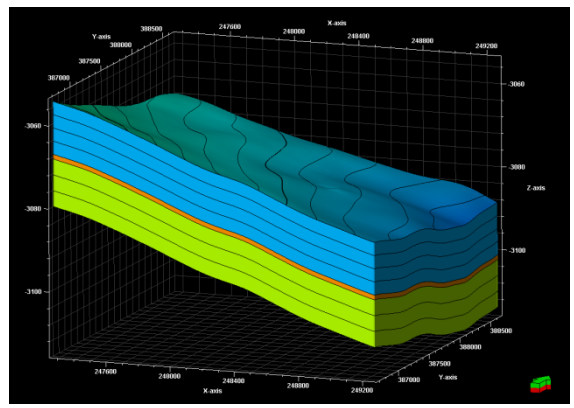

Figure 2. Model zones and layers of GS3 reservoir D Sand is blue, shaly layer, orange and E Sand, green.

Petrophysical modeling

Log data are upscaled so that each cell that is penetrated by the well will give a single value for the property. The arithmetic mean is used on the SPHI curve for porosity and permeability is calculated from the KSDR curve using the neighboring cell method.

Given that the permeability log value is available on SS31F2 only, the data plug analysis on SS31F2 and F3 is also used for permeability evaluation. After the upscaling process, the petrophysical modeling process is used to propagate the property values in the model. Since the data exist exclusively at the three wells located at the center of the model, it is not possible to use interpolation methods such as kriging or Gaussian simulation. We use instead the moving average method for both porosity and permeability distribution (Figures 4 and 5). The 3D petrophysical model obtained corresponds thus to a 200×200×8 cells grid with porosity values between 16% and 25%, and permeability values between 0.7 mD in the shaly layer and 260 mD at the base of the sand bodies.

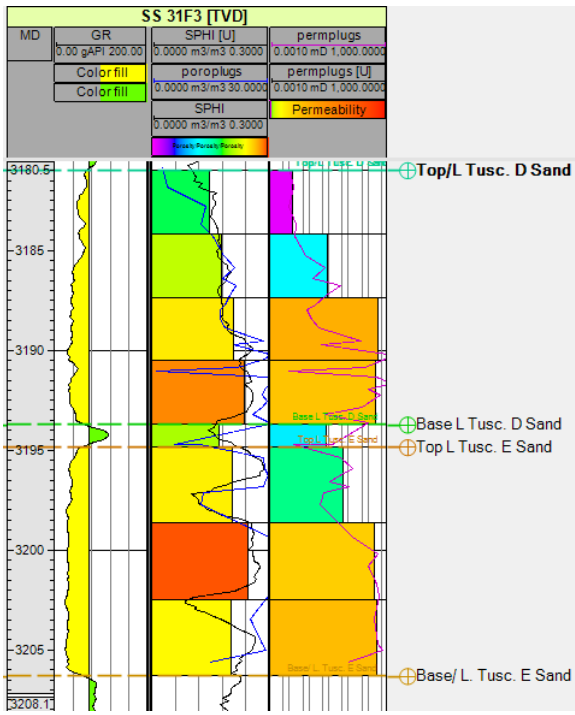

Figure 3. Example of porosity and permeability upscaling on SS31F3 well

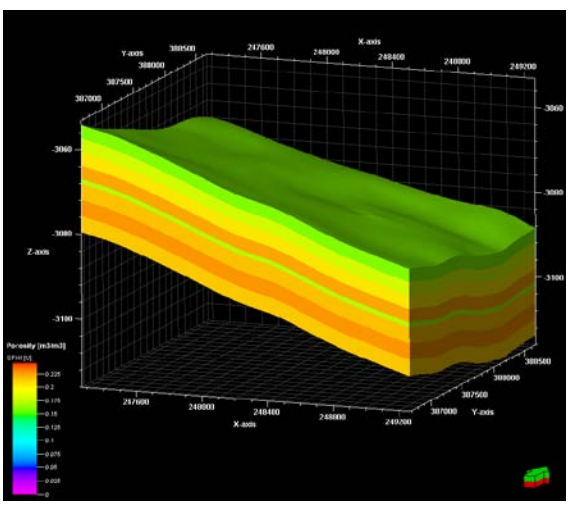

Figure 4. Porosity model of the S3 site

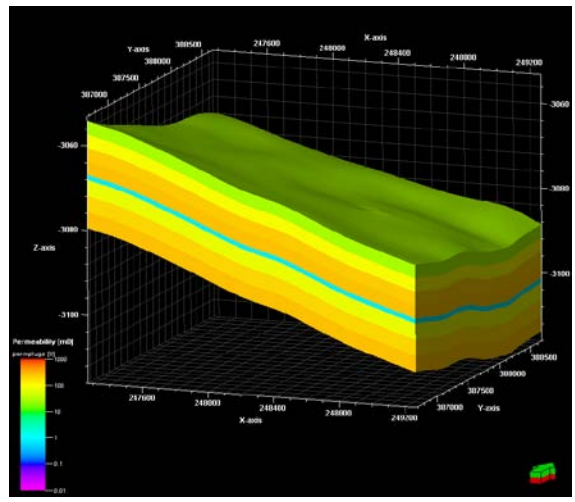

Figure 5. Permeability model of the S3 site.

MULTIPHASE FLOW SIMULATION USING 3D STATIC MODEL

To perform the multiphase flow simulation of CO_2 injection with the 3D static geological model described in the previous section, we first proceed to convert the Petrel model to a TOUGH2 format.

Conversion of geological model

We use an in-house toolbox (Audigane et al., 2011) to convert the 3D static geological model into the TOUGH2 mesh format. In this model, no faults have been accounted for. Some adaptation of the mesh geometry is also required to respect the integral finite-difference scheme used in TOUGH2. From the Petrel grid, we calculate the exact volume and the exact center point of each grid cell, and we calculate approximate values for the interface area and the distances of a connection between two cell centers as required by TOUGH2. Indeed, the grid cells exported from Petrel in the Eclipse format (.grdecl) can generate non-plane faces (with four nodes of the surface not aligned in a plane). Therefore, we calculate a new median plane between the four nodes and use the orthogonal projection of the nodes on this plane to calculate the new interface area. We then use the point of intersection between the line joining the two centers of the two neighbor cells and this plane to calculate the connection distances.

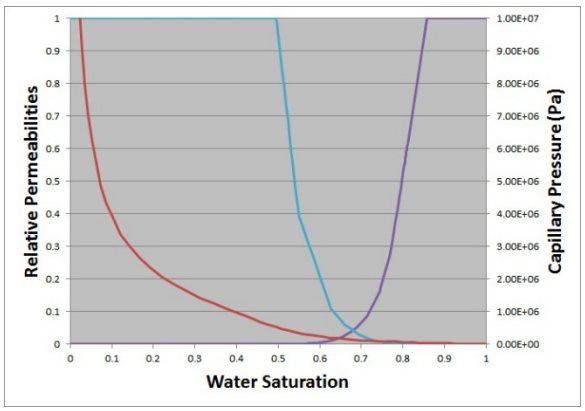

Figure 6. Relative permeabilities and capillary pressure curves used for the simulation of CO_2 injection

Simulation of CO_2 injection

The injection well SS31F1 is at the center of the model, and the two observation wells SS31F2 and SS31F3 are at distances of 223 and 364 ft, respectively, from the injection well.

Initialization and parameters

Initial hydrostatic pressure is calculated with an average value of about 3.25×10^7Pa, the temperature is fixed at 103°C, and a salinity of 15.7% weight is applied. Capillary pressure and relative permeability curves have been fitted to the data obtained by the samples tests (Fig. 6). The flow rate for the CO_2 injection was taken at 5.8 kg m^{-3} during 1 year.

Simulation of CO_2 injection

We use the massive parallel version of TOUGH2-MP (Zhang et al., 2008) with the ECO2N module to overcome CPU-time and memory constraints arising from the large number of gridblocks. Simulated arrival times at the observation wells are about 11 days and 34 days for the SS31F2 and SS31F3 wells, respectively. Figure 7 shows the evolution of gas saturation along the first and second observation wells. Figure 8 shows the extension of the plume of gaseous CO_2 in the aquifer just before the arrival at the 2^d observation well.

Differences between the model predictions and the well observation can be explained by several factors, like the presence of methane in the real reservoir (neglected in this study), the large level of uncertainty regarding the permeability distribution, capillary pressure, and relative permeability curves. For instance, gaseous CO_2 in Figure 7 can easily flow through the shale layer in our model, which is very questionable.

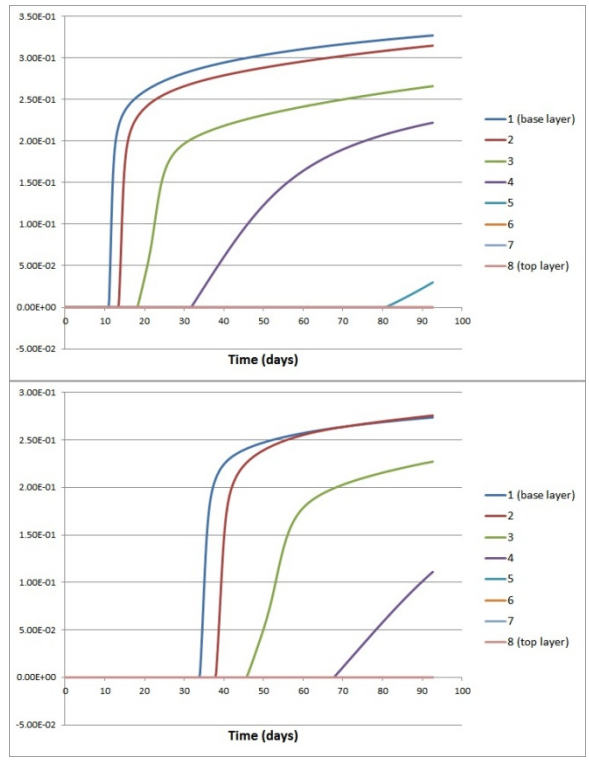

Figure 7. CO_2 gas saturation along the SS31F2 (top) and SS31F3 (bottom) wells, CO_2 arrives first in the bottom of the aquifer

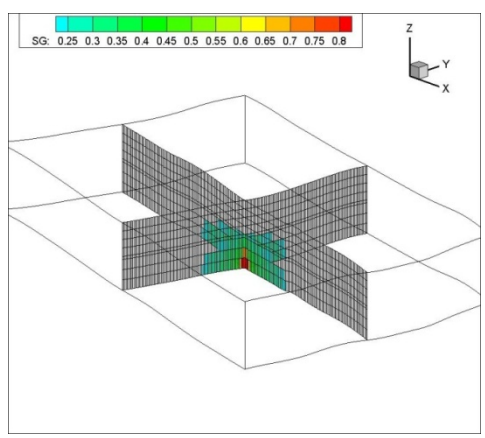

Figure 8. CO_2 gas saturation in the aquifer at 33 days

CONCLUSION

As part of the comparative study project Sim-SEQ conducted by LBNL, BRGM proposes to predict the hydrochemical behavior of a CO_2 injection conducted at the S-3 site, an anticline

sandstone formation originally used for methane production. After we built a 3D model of the geological formation with the geomodeler Petrel, our predictions of arrival time for the CO2 plume at the observations wells were found to be at variance with field data, with discrepancies associated with the high level of uncertainty regarding reservoir properties.

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