Geomechanical analysis for feasible CO_2 storage in an Indian mature oil field

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Keywords

Pore Pressure, Geomechanical moduli, CO_2 storage, Cambay basin

Summary

Geomechanical assessment is a very vital step in geological CO_2 storage project to minimize the potential risk for CO_2 leakage through fracture pathways and fault re-activation caused by CO_2 injection. A good monitoring system of geomechanical properties such as in-situ stress, rock stiffness and strength could actually control the potential CO_2 leakage pathways. Moreover, a safe and successful storage practice requires wise selection of suitable wells, especially in mature oil field.

CO_2 storage is an imminent technology in India and no hydrocarbon reservoirs have experienced it. In this view, we selected a mature oil field from Cambay basin and conducted geomechanical analysis for successful implementation of CO_2 storage. The main aim of this study is to ensure that the cap rock integrity is not disturbed due to CO_2 injection in this mature oil field. Pore pressure, fracture pressure including geomechanical moduli have been computed to better understand the subsurface formation of the studied oil field in terms of its CO_2 sequestration potential. The results obtained indicated that the present field under study has good prospect for safe CO_2 storage.

Introduction

In recent years, CO_2 capture and storage (CCS) has emerged as an important technology for mitigating the anthropogenic CO_2 emissions into the atmosphere, and hydrocarbon reservoirs are appealing to be safe for long term CO_2 storage sites due to their historic record of trapping buoyant fluids for millions of years, implying the presence of effective trap and seal mechanisms (Chiaramonte, 2008; Bickle, 2009; Ganguli et al., 2016a; Ganguli 2017). Further, the advantage of CO_2 storage in mature hydrocarbon fields is the fact that much of the surface infrastructures for fluid injection (e.g. well-bores, compressors, pipelines) are already made available in the field, which can be fully utilized.

Nonetheless, it has been previously reported that CO_2 injection into the reservoir can cause changes in the pore pressure and stress field that could potentially create/reactivate fracture networks in the sealing cap-rocks or triggering slip on the pre-existing faults by reducing the effective normal stress on fault plane (Hawkes et al., 2005; Lucier et al., 2006), providing a pathway for CO_2 leakage. In this view, it is equally necessary to ascertain the safety associated with the CO_2 storage operation for a worthwhile carbon management solution. If the potential for CO_2 leakage is significant, then the project will not be encouraged even though it possesses the needed capacity (Lucier et al., 2006). A key step in the risk assessment for geologic carbon sequestration project is the ability to predict whether the increased pressures associated with CO_2 injection are likely to affect the seal integrity and well-bore stability or not.

The objective of the present study is to establish a geomechanical model for Ankleshwar reservoir, a mature oil field in Cambay basin (Western India), which can be useful input prior to the field scale safe CO_2-storage operations. It is essential to evaluate the strength of this reservoir when subjected to long term CO_2 injection for its sequestration. In this perspective, we developed a preliminary geomechanical model to estimate the pore pressure, in-situ stresses in the reservoir using available well log data from the four wells drilled through the Ankleshwar formation in Cambay basin.

Methodology for various pressure estimation

Plumb et al. (1991) has suggested the following equation to estimate the overburden stress/vertical stress at a depth *h* (for a continuously stratified fluid), which is given by

$$S_v(h) = g\int_0^h \rho(h)dh \quad , \qquad (1)$$

where, $\rho(h)$ is the bulk density of the overlying rock, represented as function of depth (*h*), and g is the acceleration due to gravity.

The pore pressure (PP) is calculated using Eaton's sonic and resistivity equations (Eaton, 1975), given by

$$PP = S_v(h) - (S_v(h) - P_{hyd}) \times (DTn/DT)^3 \quad , \qquad (2)$$

$$PP = S_v(h) - (S_v(h) - P_{hyd}) \times (R/Rn)^3 \quad , \qquad (3)$$

where, P_{hyd} is the hydrostatic pressure; DTn and Rn are sonic travel time and formation resistivity respectively against shale zone, which are calculated from the normal compaction trend (NCT); DT is observed sonic travel time and R is the measured true formation resistivity.

Further, the minimum horizontal stress (S_h) in terms of the Poisson's ratio (σ) can be estimated using the Eaton's equation (Eaton, 1975):

$$S_h = PP + [\sigma/(1-\sigma)] \times (S_v(h) - PP) \quad , \qquad (4)$$

Matthews and Kelly (1967) introduced a variable of effective stress coefficient for fracture gradient (FP) prediction, which is as following

$$FP = PP + Ko \times (S_v(h) - PP) \quad . \qquad (5)$$

Here Ko is the effective stress coefficient = S_h/S_v, which can be obtained from leak off test (LOT) and regional experiences.

Description and Geological setup of the study area

Ankleshwar oil field, the study area is situated in the Cambay basin, which is one of the main onshore Cenozoic oil basins of India. The field was discovered in 1960 and started producing oil since August 15, 1961. At present, the field is at its mature stage, and the oil production has declined dramatically. This field has been chosen as a prospective CO_2 sequestration site followed by enhanced oil recovery (Ganguli et al., 2016a; 2016b; Ganguli, 2017).

The reservoir formation of the study area is of middle to upper Eocene age, and further divided into four main members, covered with thick sand sequence (Ardol and Hazad) and shales (Telwa and Kanwa). Figure 1 depicts the stratigraphy of the study area.

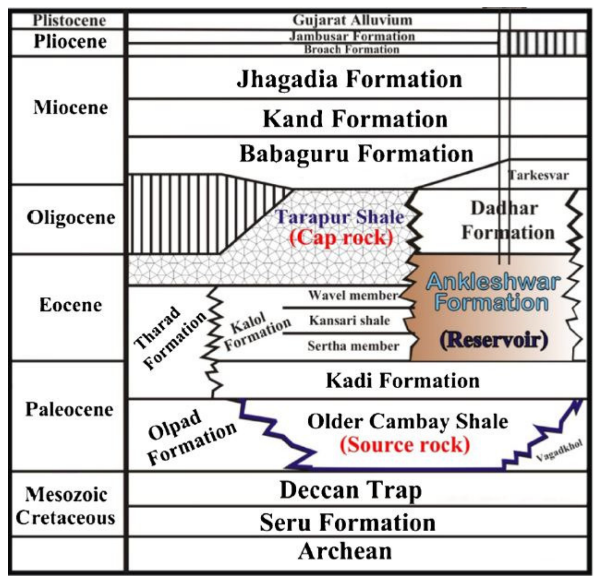

Figure 1: Schematic litho-stratigraphy distribution of the study area.

In this oil field, sediments were deposited over the Deccan trap, ranging from Paleocene to recent age. In total, the Eocene sandstones, broadly separated into 11 layers (S_1-S_{11}), constitute the reservoir, where S_1 to S_5 represents the middle sand group and S_6 to S_{11} represent the upper sand group (ONGC India Pvt. Ltd, personal communication).

It is identified that the potential layers for CO_2 injection for storage are S_3 and S_4 layers that are clubbed together, and are referred as S_{3+4} in the entire paper. The potential CO_2 storage layers, S_{3+4}, including Hazad top and Deccan trap can easily be visualized in the seismic section as depicted in Figure 2. The average porosity and permeability of the target layers are 23% and 1000 mD respectively (Ganguli et al. 2016a; Ganguli et al. 2017).

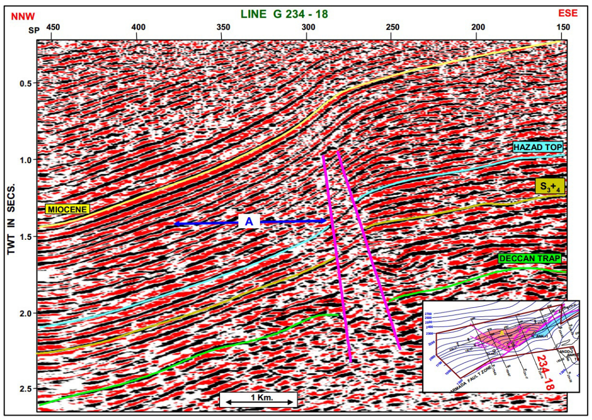

Figure 2: Seismic section displaying the potential zone for CO_2 injection, S_{3+4}, from the study area (ONGC India Pvt. Ltd, personal communication).

Data

Available data for this work covers four well-log data including P-wave velocity (Vp), density, resistivity, and gamma-ray. For the studied wells, gamma ray and resistivity logs were available both in 12 ¼" and 8 ½" sections. Compressional sonic slowness and density data were recorded only in 8 ½" section.

Faust equation (1953) has been applied to compute the synthetic compressional sonic slowness from resistivity log in 12 ¼" section and appended with measured sonic to get a composite compression sonic slowness log covering both 12 ¼" and 8 ½" sections (Sen et al., 2017).

Further, Gardner equation (1974) has been used to compute synthetic density data from available sonic log. Miller equation was applied to generate pseudo density for top hole section, where log measurements were unavailable. Miller and Gardner densities have been appended with wire line density log to get a composite density log along the full depth section of the well, which has been further used to compute overburden pressure and gradient.

Geomechanical analysis: A case study from Cambay basin

From a geomechanical perspective, a suitable site for CO_2 storage followed by EOR should have sufficient injectivity while maintaining cap rock integrity. Otherwise, wellbore stability will be disturbed since wellbore stability is dominated by the in-situ stress system. Geomechanical analysis with available well logs for the studied field would aid in the assessment for safe CO_2 storage.

Prior to computing the pressure system for the studied oil field, well log data analysis is done, the most common practice in oil industry. Shale zones were identified based on the gamma ray log readings by examining the Vshale (i.e. shale volume) cutoffs, supported by wellsite and interpreted lithology data. Normal compaction trend lines (NCT) have been drawn on resistivity as well as sonic data against shale zones and pore pressure has been computed using Eaton's method as stated earlier. Both Eaton's and Mathews & Kelly methods were applied to calculate fracture pressure for this study.

Figure 3 displays the computed overburden-pore pressure-fracture pressure profiles from resistivity and sonic data along with plotted mud weight data, used in drilling the two sections (12 ¼" and 8 ½").

We have also estimated the pore pressure after CO_2 injection, which can be treated as the assessment for CO_2 storage at the studied field (Figure 4). The elastic properties of the combined CO_2 and reservoir fluid system model was taken from Ganguli (2017). We assessed that an average of 15% change in pore pressure is expected as a result of CO_2 injection, which is assumed to be safe for CO_2 storage if not exceed the fracture pressure of this mature field.

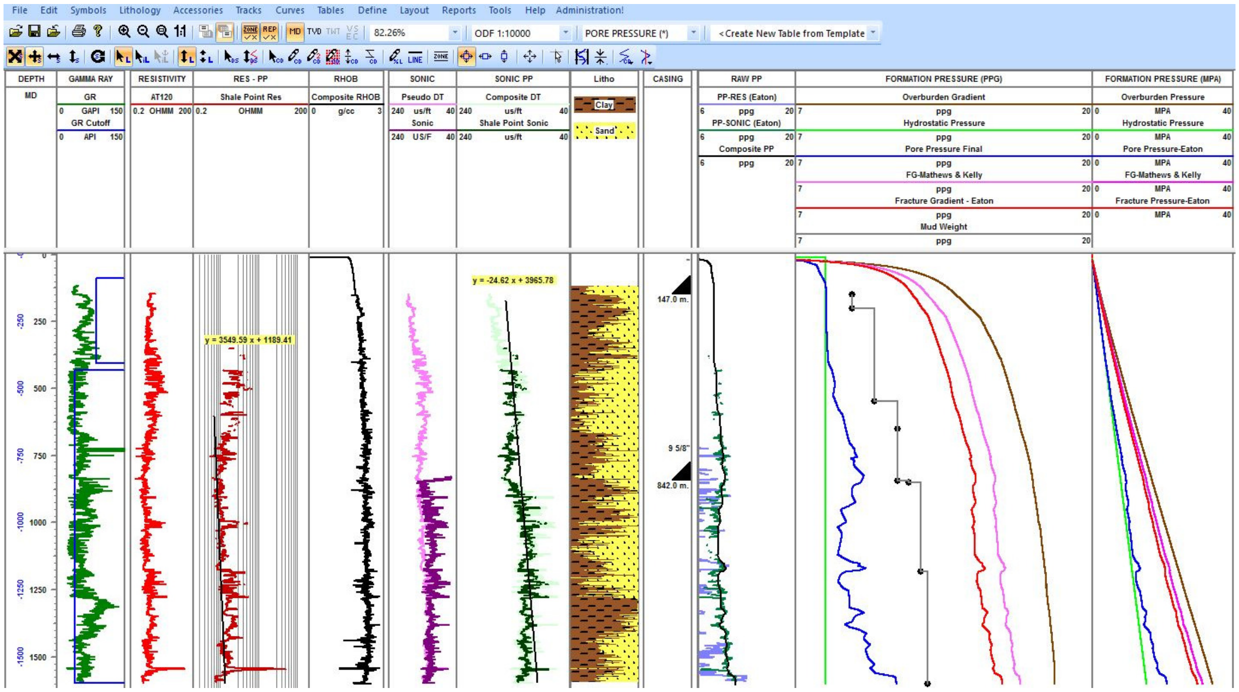

Figure 3: Estimated overburden, pore pressure, fracture pressure using resistivity and sonic logs recorded in the studied oil field, Ankleshwar in Cambay basin, output taken from Pore pressure module, GEO suite of software.

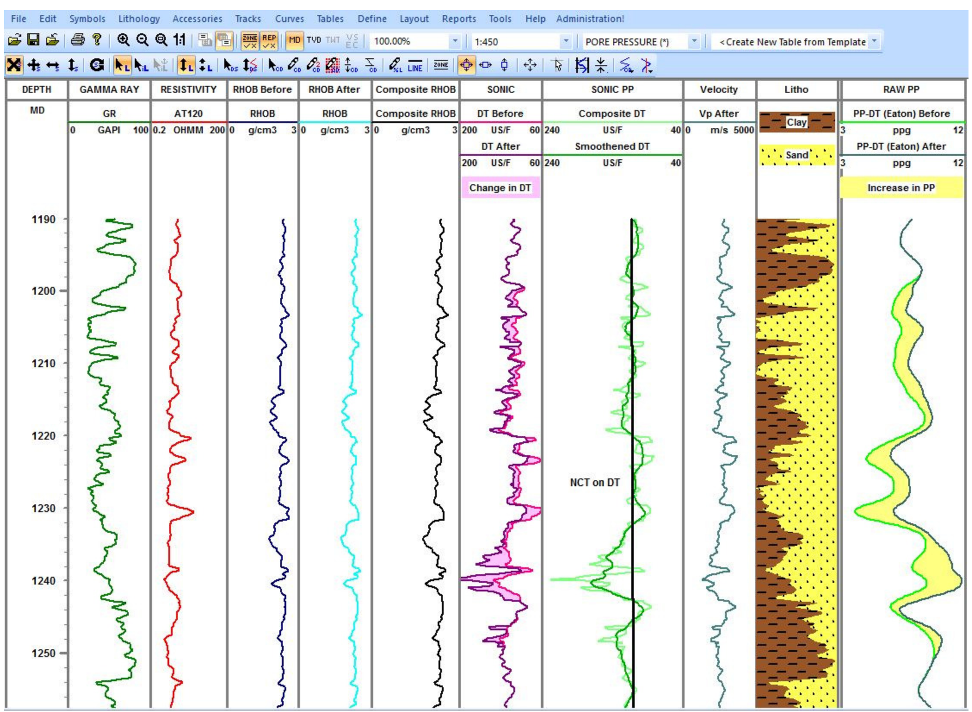

Figure 4: Representation of post CO_2 injection pore pressure envisaged using sonic logs recorded in the studied oil field, output taken from Pore pressure module, GEO suite of software.

Calculation of Shear Slowness and Geomechanical moduli

Various empirical relationship between Vp and Vs (P and S wave velocities, respectively) have been reported in many literatures. The S-wave velocity predictor by Han (1986), Castagna et al. (1993), and Mavko et al. (1998) follows the same form of the equation as given below:

$$Vs = E1 \times Vp - E2 \;. \qquad (5)$$

Where E1 and E2 are the associated constants, with a range of values proposed by different workers, i.e. E1 and E2 values range between 0.79-0.85 and 0.78-1.1, respectively for clastic rocks. We have used the values of these two constants as 0.80 and 0.86 (Castagna et al., 1993) to compute the shear wave velocity, Vs, and hence shear sonic slowness for the studied wells. Figure 5 demonstrates various geomechanical moduli such as Poisson's ratio, bulk modulus, shear modulus and Young's modulus using available wire line compression and shear sonic slowness, density logs from the studied field. Other properties such as cohesive strength, and unconfined compressive strength (UCS) have been calculated from the observed Vp (Figure 5). We found that Telwa and Kanwa shale formations, cap rocks of this reservoir, exhibit higher values of Young modulus and UCS with reasonably good cohesive strength, suggesting sufficient strength to bear the load of injected CO_2. With the results obtained from the present study, we can infer that it is very unlikely that cap rock integrity will fail due to CO_2 injection. This would have applications in determining the maximum injection capacity and pressure to avoid unsealing the cap rock or reactivating any fault or fractures. Nevertheless, a detailed experimental tri-axial test on core samples from this reservoir would aid in better understanding of risk of CO_2 storage in this field, which is beyond the scope of the present work.

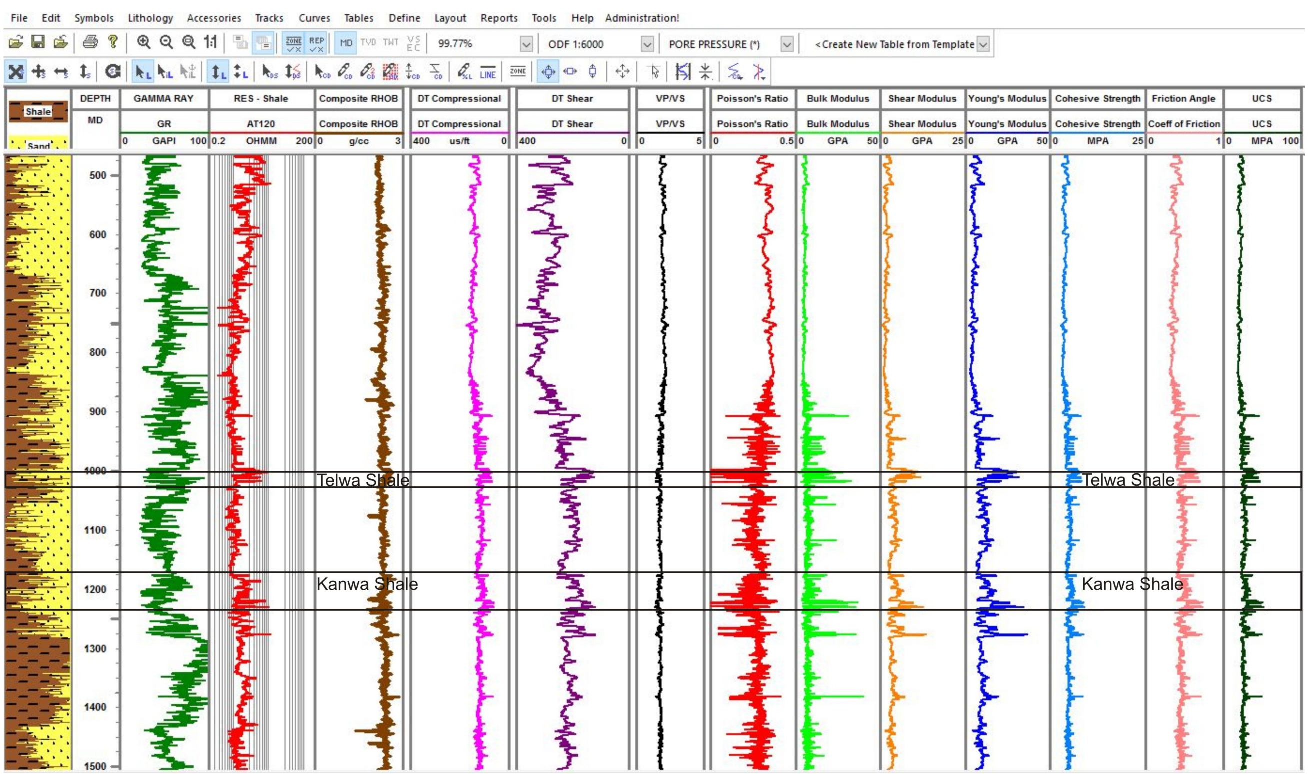

Figure 5: Computed shear sonic slowness, geomechanical moduli and UCS from one of the studied wells. The cap rocks, Telwa and Kanwa shales are marked by black colour boxes, output taken from pore pressure module, GEO suite of software.

Conclusions

The long-term fate of injected CO_2 into the geological formation for its safe storage depends on the cap rock and well integrity as well as hydraulic integrity. In the present paper, we attempted to understand safe CO_2 storage in an Indian depleted oil reservoir at Cambay basin as a case study by analyzing the geomechanical moduli and pore pressure behavior both at pre-and–post CO_2 injection scenarios. Pore pressure characteristics including geomechanical properties for the subsurface formation of Ankleshwar oil field were established using available wireline log data. The cap rocks, Telwa and Kanwa shale formations were found to be very competent and stiff. This study can help to determine suitable well locations for CO_2 injection in the field so that increase in pore pressure should not disturb the cap rock integrity for safe CO_2 storage implementation. Nonetheless, a few tri-axial laboratory tests are recommended prior to implement CO_2 storage in field scale.

Acknowledgements

Authors would like to convey their gratitude to ONGC for providing the well dataset for this study. Also the authors thank Geologix Ltd. for giving the access to use the Pore Pressure module of GEO Suite software. SSG thanks DST Inspire Project, Dept. of Sc. & Tech., Govt. of India for funding this work.

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