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Petroleum & Petrochemical Engineering Journal
ISSN: 2578-4846

Role and Advancements in Geomechanical Challenges in Carbon Capture and Sequestration

Biswas T*

Oil and Natural Gas Corporation Ltd, India

***Corresponding author:** Tuhin Biswas, Oil and Natural Gas Corporation Ltd, India, Email: tbtuhin24@gmail.com

Short Communication
Volume 7 Issue 2
Received Date: May 01, 2023
Published Date: May 18, 2023
DOI: 10.23880/ppej-16000348

Abstract

Anthropogenic CO_2 emissions rapidly increased during the post-industrial revolution causing global warming issues. In order to reduce the CO_2 concentration in the atmosphere Carbon Capture and Sequestration will play a key transition role to transform into clean energy by utilizing the existing oil and gas infrastructure and subsurface data. The technology comes with certain challenges, amongst them, one of the real threats is the stored CO_2 leakage back into the atmosphere and at shallower surfaces. This work talks about the understanding of geomechanical risks involved in the CCS process and probable ideas to mitigate the risks. CO_2 injection leads to an increase in the pressure within the pores which eventually results in a change of stress and strain conditions within the reservoir. With a proper understanding of the reservoir and with a realistic field dataset a controlled injection can avoid a formation leading to geomechanical failures. Often field data are insufficient, in such a scenario this works talks about the preventive measures that can be adopted to avoid early mentioned calamity.

Keywords: Geomechanical Challenges; Carbon Capture and Sequestration

Introduction

Carbon dioxide is a primary contributor to greenhouse gas emissions. It can be stored in subsurface conditions within saline aquifers, as they are abundant and provides adequate capacity [1,2]. However, this storage method is not foolproof; it comes with certain geomechanical challenges and risks. CO_2 injection increases the pore pressure and can lead to caprock failure, reactivation of pre-existing faults, abnormal poroelastic response, surface uplift, induced seismicity contamination of drinking water, and soil pollution [3,4]. To mitigate CO_2 migration risk to shallower depths, understanding the lithostratigraphic context of the proposed repository, the state of stress and the reservoir geomechanics processes become important.

Fortunately, there is no report of significant carbon leakage from carbon sequestration since its inception in 1996 in the Sleipner oil field in the North Sea [5]. But low induced seismic risk remains one of the basic criteria for a carbon sequestration site selection. Carbon dioxide leakage potentials can be divided into two broad categories, (i) Leakage potential from abandoned wellbores and (ii) leakage potential from geological formation through weak planes. A poor abandoned well database possess a real threat in identifying potential leakage areas whereas, within geological formation fault geometry, the existence of blind faults, critically stressed faults and fractures adds computational expenses [6].

To efficiently understand the geomechanical risks, a multiscale model of the reservoir is essential [7]. Models such as the single-phase analytical model [8], hybrid analytical-2D numerical simulation model [9], fluid simulation model [7], geomechanical model [10] previously addressed the leakage issue along the fault paths. But, in recent years numerical modelling combined with reservoir flow simulation and geomechanical models achieved quite a success to predict rock failure behaviour under CO_2 injection [4]. Coupled simulators such as TOUGH-FLAC3D [11,12], GEM-COMSOL [13], Eclipse-VISAGE [14,15], ABAQUS [16], plays a pivotal role in geomechanical application for carbon dioxide storage. However, the efficiency and accuracy of the model only increase with the valuable addition of field data.

Previous Studies

Change in pore pressure during gas and fluid storage modifies the magnitude of horizontal stresses leading to the potentially irreversible mechanical change within the *in situ* rock, increasing the possibility of injection-related seismicity, caprock failure, and reactivation of existing faults [17-19]. Detailed knowledge of pre-existing faults, fault slip potential, criteria for generation of new faults and fractures, local and regional stress regimes, and earthquake focal mechanisms contribute significantly to the geomechanical understanding of the reservoir subjected to injection [20-22]. Based on such valuable information, a comprehensive geomechanical model of a CO_2 repository reservoir can be created. An accurate evaluation of the magnitudes, the direction of principal stresses, and pore pressure [23,24] while creating the model can help understand the potential for unfavourable outcomes and thus guide operational outcomes as detected by sensor arrays for seismic surveys, deformation and induced seismicity.

Data Acquisition and State of Stress

Pore pressure data can be acquired from the Drill Stem Test, the Repeat Formation Test, borehole geophysical logs, seismic data, and drilling mud weight values [25-27]. The orientation of principal stresses is derived from borehole breakouts and tensile fractures, earthquake focal mechanisms [25,28]. There are many methods and direct measurements to estimate the magnitude of the stresses such as density log data (for S_v magnitude), poroelastic horizontal strain model, empirical tectonic factors, image log data, borehole failure data, earthquake focal mechanism inversion technique (for Sh_{max} magnitude) and specific activities such as Leak-Off Tests, Hydraulic Fracturing Tests and Pressure While Drilling, and Diagnostic Fracture Injection Test (for Sh_{min} magnitude) [22,27,29,30]. Based on the principal stress magnitude and directions, the state of stress can be specified and extrapolated regionally, given adequate data. In general, studies show that elevated compressive regional stress is more conducive to rock slip within a reservoir [31].

Identifying pre-existing faults, particularly critically stressed faults, is crucial to probabilistically analyze and assess reservoir containment before a major prolonged injection period. Providing that injection pressures do not exceed the minimum principal stress, rock commonly fails under shear failure and pre-existing faulted/fractured rocks require special attention in the framework of Mohr-Coulomb failure analysis [4]. Within the subsurface, fault specification (undetected faults, small faults, unknown lateral continuity of a fault system, fracture orientation) is needed. Then, pore pressures, local stress of faults, elastic properties and frictional/cohesive strength specification present real challenges. To quantify uncertainties, the probability of the fault plane slipping can be expressed as:

$$P_f = P\left[\tau - \mu\sigma_n \leq 0\right] \quad (1)\ [22]$$

Specifying Mohr-Coulomb failure criteria in a probabilistic manner, fault planes which are most susceptible to slip can be identified.

To avoid a fault plane slipping under shear failure, Ferronato, et al. [31] introduced a safety factor by which the threshold margin of injection pressure can be detected.

For shear failure a safety factor can be expressed as:

$$\chi = 1 - \left(\tau_m / \tau_m^*\right) \qquad (2)$$

In which τ_m is the current largest shear stress and τ_m^* is the maximum allowable shear stress.

For tensile failure safety factor is presented as:

$$\Psi = \frac{\sigma 3}{\sigma 3,0} \qquad (3)$$

Where $\sigma 3,0$ is the initial minimum principal stress. When $\Psi = 0$, tensile fracture is induced.

Changes in stress conditions can lead to the opening of microfracture networks, reactivate pre-existing faults, and create induced fracture, leading to micro-seismic risk to the formation [32]. Studying the change in stress path is an accepted method to identify the slip potential of the fault plane and determine allowable maximum injection pressure [19].

Possible Areas Undergoing Geomechanical Changes

Within a reservoir, there are areas more vulnerable to brittle deformations. Over-pressured zones have lower effective stresses and are more prone to slip, thus, requiring special consideration during injection simulation [4,22]. Moreover, the lower boundary of the cap rock is the weakest zone to initiate a slip surface and this tendency is influenced also by the thermal expansion coefficient and elastic properties of the rock [4,33]. Even sufficient temperature differences can cause fractures to develop within the caprock [34].

The distribution of injected CO_2 is driven by heterogeneous permeability distributions in the subsurface [35]. Rutqvist, et al. [33] observed a proportional relation between permeability and the change in effective stress after the injection of CO_2. Thus, it is essential to consider the various geomechanical factors together to provide realistic simulations and reliable probabilistic assessments.

Effective stress within the formation is reduced with the injection of CO_2. This can lead rock to fail in three different ways:

- An immediate slip on the critically stressed planes under the influence of high pore pressure, especially in the areas close to the injection point, therefore further reducing the stress-bearing capacity.
- Modified stress magnitudes of much larger scale leading to the slip of distantly placed weak planes at roughly the same depth.
- Prolonged injection with an accumulation of additional stress triggering faults at different depths [36-38].

Geomechanical Simulation Studies

To ensure safe injection, reservoir simulation involving CO_2 and brine flow coupled with geomechanics analysis provides a better estimation of the hydrofracturing and stick-slip threshold values as compared to single-phase flow models [21]. If the reservoir itself is faulted, it can be analyzed by the finite-thickness element approach [20]. However, knowledge of subsurface parameters is often somewhat sparse and not regularly distributed, thus a probabilistic approach is the best way to model the injection-related geomechanical changes and therefore outcomes. Such an approach can deal with stress magnitudes, the orientation of the principal stress, fault orientation and dip, and frictional coefficient-related uncertainties [36,39]. Fluid flow coupled with geomechanical simulation (e.g., GEM-COMSOL, Eclipse-VISAGE, TOUGH-FLAC, ABAQUS) helps to identify the risks involved in the form of surface upliftment, induce seismicity, reactivation of faults, generation of new fracture networks.

With a probabilistic geomechanics approach, the San Juan CarbonSAFE project in the USA was identified as having low-induced seismicity potential [40].

With a controlled injection pressure, tensile failures can be avoided within the rock [32]. However, on the other hand, a tensile crack can appear under low differential stress conditions for critically-stressed faults and fractures which further decreases the value of the maximum allowable pressure of injection [41]. The rock's mechanical strength and geometric characteristics can be comprised of the reaction of CO_2 with minerals, leading to drastic changes in local stress conditions [42].

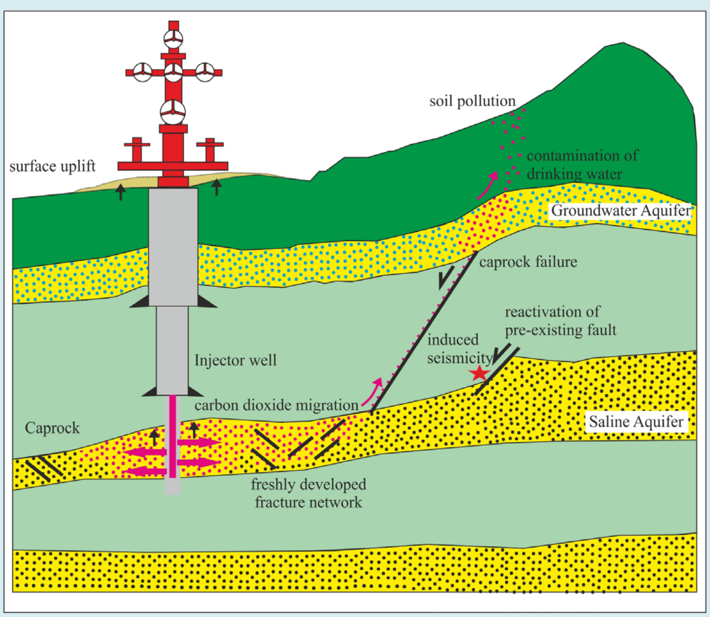

Figure 1: Conceptual diagram of CO_2 leakage from geological storage under a high CO_2 injection rate. The pink colour represents injected CO_2. Black straight lines indicated weak planes (faults and fractures). Blue dotted circles indicate ground/ drinking water. Black solid arrows indicate surface upliftment. The black half arrow indicates the slip direction of the fault plane. The red star indicates seismic activity. Diagram not to scale.

Discussion

The CO_2 storage project in In Salah, Algeria, was identified with injection-induced faulting. This is a classic case of fracture reactivation and the area is now identified with potential microseismic activity area [43]. Regular monitoring of CO_2 injection not only helps to detect valuable information but also helps to initiate preventive measures against early warnings. Several monitoring methods such as geophysical survey (microseismic activity analysis), hydrogeochemistry and surface soil gas technique, and shallow well monitoring of underground fluids are capable of detecting CO_2 leakage [44-46]. However, none of them is infallible. At Svelvik in Norway, a shallow-level (20m) CO_2 injection test resulted in an unpredictable CO_2 gas escape route, which further demands the improvement of existing fixed monitoring methods [45]. Carbon dioxide can leak at an uncontrollable rate under the existence of faults and fractures. In such a scenario, polymers, gels and foams can be used to choke porous and permeable zones and reduce fluid mobility [6]. Recently, the microbially induced carbonate precipitation (MICP) technique yielded a positive result in treating fractured concrete with a 26-50% recovery of the initial tensile strength [47]. With proper tuning, this method has the potential to become successful in treating densely induced fractured intervals. Although the preference should always be not to initiate fault and fracture networks by controlling the CO_2 injection rate [48].

Conclusion

CO_2 is one of the primary contributors as a greenhouse gas that can be stored in subcritical conditions within saline aquifers as they are abundant and provides more capacity. However, the storage method comes with certain geomechanical risks which need to be eliminated before identifying a reservoir as a suitable storage site. Such risks involve the reactivation of faults, creation of new fractured networks, induced seismicity, surface upliftment and migration of CO_2 from the leaked path to shallower levels. This work reviews the recent advancements in geomechanical challenges in carbon capture and sequestration. Reservoir Modelling can only be performed close to reality with the availability of the field data. In case of the non-availability of the dataset, a probabilistic statistical approach can possibly be a good option to identify the leakage risks. With a close post-injection monitoring method, it is possible to identify an early indication of geomechanical failure. In case of a rock failure under injection pressure, there are methods that exist to choke or treat the fractured interval and help them recover their strength back.

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