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Seismic-Integrated GeoMechanics Assessment Plan (Sigma-P) for Luna CO_2 Storage Site in Norwegian North Sea

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Summary

Inclusive evaluation of geomechanical risks is critical to ensuring the reliability of geological carbon storage. While poromechanics has long established the relationship between injection-induced pore pressure changes and potential rock failure, managing the large-scale geomechanical risks linked to CO_2 injection into deep saline aquifers remains a key hurdle for its broader adoption in the global transition to net-zero emissions. In this study, we explore the mechanical behaviour of the Luna saline aquifer in the North Sea under CO_2 injection through integrated simulations that couple multiphase flow with geomechanics, based on a seismic-driven high-fidelity static model. Our findings indicate a surface uplift of approximately 13 mm after two decades of continuous injection at 1.5×10^6 m³/day (equivalent to 1 Mt/year), a level deemed safe for offshore infrastructure. Furthermore, our analysis reveals maximum shear stress level (SSL) and tensile stress level (TSL) of 0.5 and 0.78, respectively, in both the reservoir and the overlying caprock. Given that stress levels under 0.8 are considered safe thresholds, our results imply a low probability of gas injection-induced mechanical failure, reinforcing the integrity of the caprock and supporting the long-term feasibility of CO_2 storage in this setting.

Introduction

Geological storage of carbon dioxide is recognized as a key strategy in the pursuit of a net-zero emissions future. Rigorous geomechanical modelling of CO_2 injection into deep saline aquifers plays a vital role in understanding CO_2 plume migration, pressure buildup, and associated risks such as ground uplift, wellbore and caprock integrity concerns, and induced seismicity (Haghi et al., 2013; Zoback, 2010). Multiphase fluid flow simulation that allows for the dissolution of CO_2 in brine is essential for accurate CO_2 plume modeling (Pruess and García, 2002). Despite an abundance of numerical simulations focusing on CO_2 plume migration in saline aquifers, relatively little attention has been given to pore pressure plume migration and the resulting geomechanical hazards. This is a critical gap, as evidence shows that pressure changes can induce fault re-activation and caprock failure over considerable distances from the injection point (Zoback and Gorelick, 2012). To realistically assess these risks, large-scale geo-models encompassing all reservoirs, surrounding formations, and overlying strata are required. Moreover, geomechanical simulations benefit significantly from incorporating static models with fine structural detail, which can only be derived from high-resolution seismic data (Sengupta et al., 2011). Despite recent advancements, integrating high-resolution 3D seismic data into fully coupled multiphase fluid flow and geomechanical simulations remains a major challenge, particularly in offshore saline aquifers.

Injecting CO_2 into a brine-saturated aquifer raises pore pressure, with pressure buildup decreasing with distance from the well. Poroelastic theory predicts that such pressure increases elevate total stress while reducing effective stress, thereby inducing rock deformation (Zoback, 2010; Haghi and Chalaturnyk, 2024). If deformation becomes excessive, rocks may fail, either by

shearing or through tensile fracturing. Shear failure arises when shear stress exceeds rock strength and can be described by the Mohr-Coulomb criterion: $\tau = C_0 + \mu\sigma_n$, where C_0 is cohesion, μ is the friction coefficient, and σ_n is the effective normal stress at failure. In many cases, especially within faulted regions, it is standard to assume zero cohesion ($C_0 = 0$) and a friction coefficient of $\mu = 0.6$ (Zoback, 2010). Tensile fracturing occurs when pore pressure surpasses the minimum principal stress, often resulting in fractures that typically propagates perpendicular to the least principal stress direction, or along weak subsurface features such as bedding planes, faults, or pre-existing fractures (Zoback, 2010).

In this study, we adopt a seismic-integrated coupled numerical approach to analyse geomechanical risks associated with CO_2 storage in the Luna saline aquifer located in the North Sea. To do this, we construct a high-fidelity static model consisting of 15.5 million grid cells, incorporating reservoir, overburden, and underburden properties derived from 3D seismic inversion and well logs. We then carry out coupled multiphase flow and geomechanical simulations to assess CO_2 plume migration, pressure plume, surface displacement, and failure potential using the Mohr-Coulomb criterion. This study highlights the importance of adapting a robust simulation workflow for geomechanical risk mitigation in CO_2 sequestration operations within the Luna aquifer, which can be extended to CO_2 storage projects in the North Sea or similar geological settings.

Luna Storage Site

The Luna site is a potential carbon capture and storage (CCS) initiative in the Norwegian North Sea, situated west of the Northern Lights CCS project, in waters roughly 200 meters deep. The target for CO_2 storage is the Statfjord Formation, a Lower Jurassic sandstone reservoir located between 2500 and 3500 meters below the seabed. With high porosity (above 20%) and permeability, the Statfjord Formation is well-suited for CO_2 injection and long-term containment. Overlying Jurassic shale formations, including the Drake Formation, serve as primary caprocks, preventing the upward migration of stored CO_2.

Methodology

Static model

We developed a high-fidelity static model with grid dimensions of 1710 × 244 × 37 (15.5 million cells), incorporating the reservoir as well as high-resolution overburden and underburden properties derived from 3D seismic inversion and well-log data (Figure 1). The model spans an area of 20 × 40 km, with the brine-saturated aquifer located at depths ranging from 2500 m to 3500 m, deepening toward the northeast. We establish a robust porosity–acoustic impedance correlation using publicly available well data. We then perform seismic acoustic inversion from below the reservoir up to the seafloor and convert the 3D model to depth using well data and seismic imaging velocities. Porosity is calculated from impedance values, while permeability is modelled using a well-data-driven porosity-permeability equation.

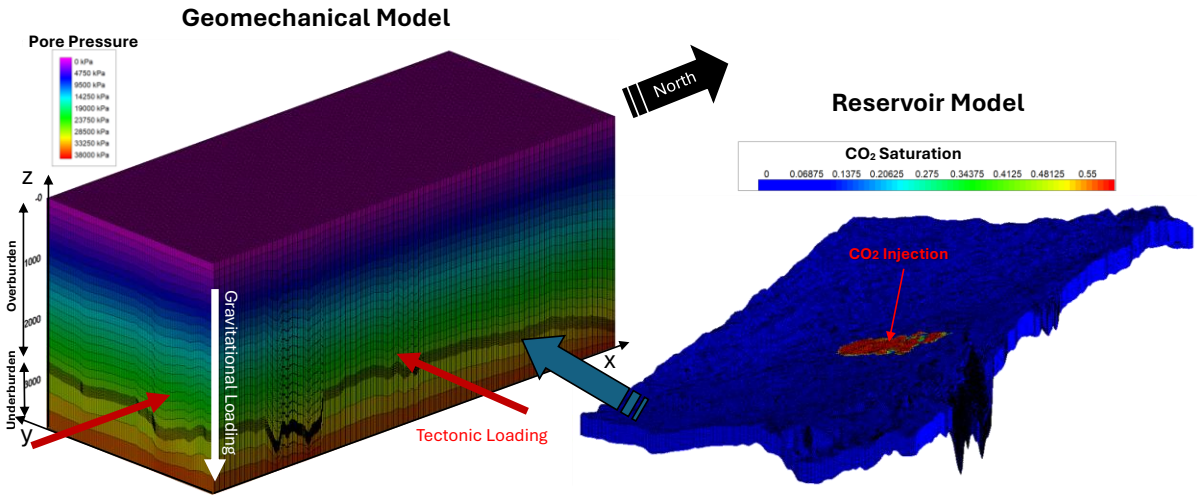


Figure 1 High-resolution reservoir geomechanical model.

Multiphase reservoir model

We use TRS black-oil module within our proprietary Geosim simulator for multiphase fluid flow simulation between gaseous and aqueous phases. Initial conditions for the model include hydrostatic pore pressure and a temperature of 100°C. We develop a two-component black-oil PVT table to replicate the behaviour of a CO_2-brine mixture model based on the Peng-Robinson equation of state. CO_2 dissolution in brine is modelled using Vasquez and Beggs correlation (Vasquez and Beggs, 1980). For relative permeability curves, we adopt Brooks-Corey exponents for mid-range permeability (10–100mD), along with endpoints and hysteresis effects taken from published CO_2-brine core-flooding databases (Bachu, 2013). A CO_2 injector is positioned down-dip within the Statfjord Formation, operating at an injection rate of 1.5×10^6 m³/day, with the goal of delivering 1 million tonnes of CO_2 per year into the aquifer over a 20-year period, starting on January 1, 2065 (Figure 1).

Coupled geomechanical simulation

We use Geosim to conduct coupled geomechanical simulations, leveraging its advanced parallel computing features optimized for high-performance computing (HPC) environments. Using FEM3D module within the Geosim simulator, we first initialize the stress field across the entire model through gravitational and tectonic loading, incorporating density, elastic properties, and boundary displacements. During the stress initialization phase, we iteratively calibrate the model using in-situ stress data from wells. The resulting 3D Mechanical Earth Model (3D MEM) imports pressure and saturation arrays from the TRS multiphase reservoir simulator at each timestep. The coupled reservoir-geomechanical approach calculates deformation and stress evolution throughout the injection period.

To assess failure risk quantitatively, we use two key dimensionless parameters for each grid cell at each timestep: (1) Shear Stress Level (SSL), defined as the ratio of current deviatoric stress to the failure deviatoric stress based on the Mohr-Coulomb criterion, and (2) Tensile Stress Level (TSL), defined as the ratio of pore pressure to the minimum principal stress. SSL and TSL range from 0 to 1, with higher values indicating a greater likelihood of shear and tensile failure, respectively.

Results and Discussion

The initial stress maps shown in Figures 2a-b reveal a north-eastward increase in both minimum and maximum principal stresses (S_3 and S_1), which aligns with the regional deepening of the reservoir in that direction. These maps also confirm that the vertical stress represents the maximum principal stress ($S_1 = S_v$), indicative of a normal faulting stress regime in the area. An azimuthal arrow in Figure 2a illustrates the predominantly North–South orientation of the minimum horizontal stress (S_{hmin}), which is consistent with the World Stress Map (WSM) database (Heidbach et al., 2016).

Figures 2c-d illustrate the asymmetric distribution of CO_2 and pressure plume after 20 years of injection into Well_1, reflecting the influence of directional stress anisotropy, structural heterogeneity, and reservoir properties. The dominant East–West alignment of the maximum horizontal stress, coupled with permeability anisotropy and gravitational gradients favouring the shallower western section, explains the westward-biased migration of the CO_2 plume. In Figure 2d, the pressure buildup—defined as the difference between the prevailing reservoir pressure and the initial state—shows a clear gradient, diminishing with distance from the injector. This pattern highlights the far-reaching impact of pressure perturbations, which could potentially re-activate critically stressed fault located several tens of kilometres from the injection site.

Figures 2e-f present the spatial distributions of SSL and TSL, computed using dynamic stress and pore pressure fields alongside cell-specific failure thresholds. These indicators provide a quantitative measure of mechanical stability related to caprock integrity in the Luna aquifer. In Figures 2e-f, the maximum SSL and TSL values of 0.5 and 0.78, respectively, suggests a low probability of mechanical failure or leakage. Notably, these results demonstrate how fine-scale heterogeneity and stress anisotropy significantly affect the SSL and TSL distributions, revealing localized zones of increased geomechanical risk. These subtleties are often missed in coarser geomechanical models, leading to potentially inaccurate safety evaluations.

Injection-induced effective stress decrease leads to heave within the reservoir, pushing the overburden layers upward. Figures 2g-h show vertical displacement responses, including approximately 1.4 cm maximum uplift at the caprock base and 1.3 cm at the seabed, resulting from a 2 MPa pressure increase near the injector over two decades of CO_2 injection. This uplift is within acceptable limits for offshore environments and indicates stable mechanical behaviour during long-term CO_2 storage.

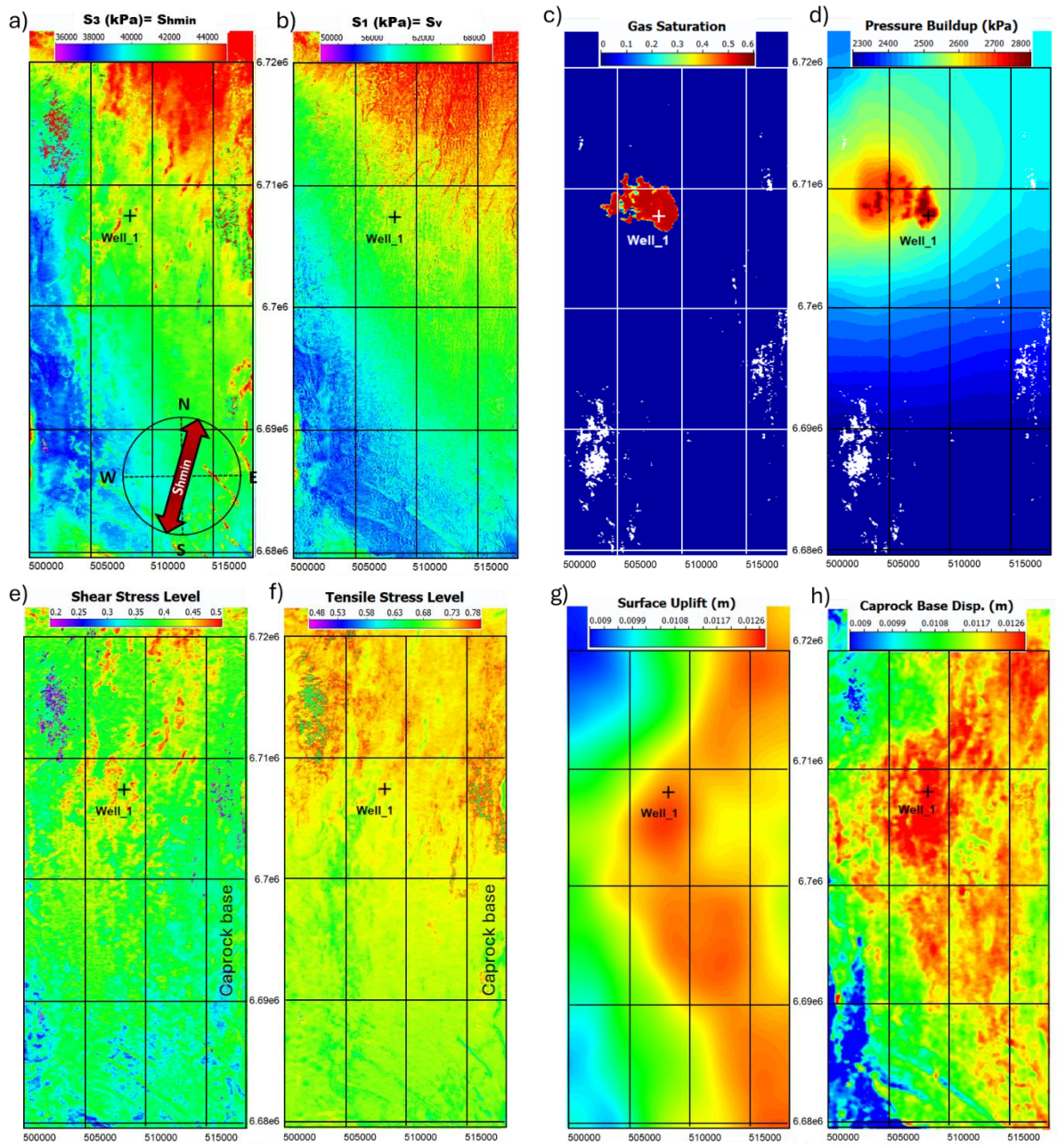


Figure 2 highlights reservoir's a) minimum and b) maximum principal stress maps at initial condition. It further shows c) CO2 plume, d) pressure buildup plume, e) caprock base SSL, f) caprock base TSL, g) surface uplift, and h) caprock base displacement maps at the end of the CO_2 injection period in 2085.

Conclusions

This study demonstrates the application of high-fidelity geomechanical modelling to assess CO_2 injection in the Luna saline aquifer, providing critical insights into how stress anisotropy, geological heterogeneity, and pressure evolution interact over time. The results from SSL and TSL calculations provide robust evidence for the mechanical stability of the storage system, predicting a low risk of caprock failure or leakage during the 20-year injection period. The importance of incorporating fine-scale structural and compositional variation is highlighted, as these factors significantly influence geomechanical responses. Beyond improving confidence in CO_2 storage safety, these findings carry broader relevance for other subsurface energy technologies, including hydrogen storage and geothermal operations, where mechanical integrity is equally essential.

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