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Geomechanical Implications for Enhanced Oil Recovery Performance and Associated Risks: An Integrative Review

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Abstract

This is a systematic review that examines the geomechanical aspects that affect the efficiency and hazards of Enhanced Oil Recovery (EOR) procedures, particularly with respect to carbon dioxide (CO₂) injection and other sophisticated stimulation techniques. Fundamental geomechanical principles, including effective stress, poro-elasticity, and rock deformation, constitute the essential basis for understanding fluid-rock interactions across various methodologies of EOR. Mechanical response of reservoir rocks during waterflooding, chemical injection, gas flooding (CO₂-N₂), and thermal recovery are fully considered, and particular attention is paid to the behavior of fractures and faults, injection induced seismicity, thermal induced deformation, and stress-permeability hysteresis. Experiences of the Enhanced Geothermal Systems have been used to seal the significance of dilation thresholds, fracture conductivity changes, moisture cyclic stiffness degradation in stress-sensitive organizations. New developments in fully coupled thermo-hydro-mechanical-chemical (THMC) simulations and field-scale calibrated Mechanical Earth Models (MEMs) are also covered. These composite frameworks will lead to the greater predictive power, the most favorable injection strategies, structural stability and the minimization of geomechanical threats. The results define geomechanical modeling to be a core principle in developing robust and high-performance EOR systems, especially in unconventional and complicated reservoirs.

Keywords: Enhanced Oil Recovery, Geomechanics, Poroelasticity, Fault Reactivation, THM Coupling, CO₂ Injection.

1. Introduction

The maximization of hydrocarbon production from mature oil reservoirs is an important task in the energy sector. The conventional oil production techniques are not able to recover a significant portion of the initially existing hydrocarbons. EOR techniques, including those involving thermal, chemical, CO₂/gas, and water flooding, are widely applied to increase displacement and sweep efficiencies in oil reservoirs [1-3]. Nonetheless, along with the properties of fluid-flow, EOR activities inevitably stimulate complex geomechanical relationships among rocks of the reservoir, formation fluids and injectants, which are also becoming recognized as key factors that define successful operation [4, 5].

In this respect, Terzaghi (1943) concept of effective stress continues to be the main foundation for understanding the rock behavior in EOR operations, as injection induced variations to the pore pressure can redistribute stresses, re-open fault inactivity and modify the porosity and permeability of the rock. These concepts have been used to carry out extensive research on the hydro-mechanical behavior of reservoirs through injection processes [6].

The impact of changes in the pore pressure and chemical reactions on the rock properties has been the subject of extensive experimental studies. As shown by Ross et al. (1982), injection of CO₂ into brine saturated sandstones, enhanced the porosity by dissolving the minerals but grossly reduced the mechanical integrity [7]. According to Madland et al. (2006), under the injection of CO₂ and CO₂-saturated water, chalk formations fail, which increases the possibility of mechanical failure [8]. A similar study conducted by Luquot and Gouze (2009) quantitatively studied the changes in porosity and permeability of carbonate rocks due to the injection of CO₂. The study confirmed the simultaneous changes in chemical composition and mechanical integrity [9]. In addition, the complexities of the geomechanics are even more compounded in the thermal-based EOR techniques. Hojka et al. (1993) have analytically shown the generation of thermoelastic stress gradients in the vicinity of boreholes, leading to shear failures, especially in the case of steam injection methods [10]. Kocabas (2006) has also investigated the impact of temperature on stress and stress-dependent flow behavior in the context of cold water injection methods [11].

One of the geomechanical hazards of EOR techniques is fault and fracture destabilization. In this regard, Chiaramonte et al. (2008) established that the pore pressure build-up in a naturally fractured reservoir can negatively affect the stability of already existing faults and the sealing capability of

the cap rock, and it can even cause the construction of leakage pathways [12]. Under this aspect, Zoback (2010) also noted that the instability of faults and fracture creation is regulated by regional stress regimes, and this directly affects the safety and viability of injection-based operations in unconventional reservoirs that have stress-sensitive behavior [3]. Cai et al. (2020) introduced a model of coupled geomechanical-chemical CO₂ foam flooding in the tight dual porosity reservoirs, which provided a possibility of a pore pressure buildup that can undermine the fault stability and sealing ability of the cap rock [13].

The complex nature of interactions among fluid flow, chemical reaction and mechanical deformation in EOR processes has stimulated the need to develop fully coupled thermo-hydro-mechanical (THM) models. These models combine both the impact of pore-pressure changes, temperature variations and chemical interactions on stress distribution, fracture propagation, and compaction of the reservoir. Laboratory-scale studies have provided insights into model parameterization, including time-dependent material responses to thermal and chemical perturbations [14, 15].

Hybrid modeling strategies have been developed as necessary solution in order to model such coupled processes at the same time so that fracture stability, caprock integrity and flow paths under different operating conditions can be predicted through assessment [16]. These models combine geomechanical, geochemical, and fluid-flow effects, which can be used to make risk-informed decisions, optimize the use of EOR strategies, and reduce the risks of mechanical failure [17].

The feasibility of these coupled processes is supported in the field with a lot of evidence. The extensive compaction and surface subsidence in chalk reservoirs with long-term producers of pore fluids, including Ekofisk field, proved the direct connection between fluid production and mechanical deformation [18]. Carbon dioxide injection in Salah project (Algeria) and the Otway project (Australia) have been discovered to produce large surface uplifts up to 1522 mm, and also injection-induced seismicity [19]. The Filanovsky Field has been using integrated monitoring methods, including 4D seismic, geomechanical and reservoir models to monitor the variability of the pore pressure and saturation [20].

In spite of these developments, current studies on EOR reviews have been more so concerned with case history classification or isolation of individual geomechanical process without providing an integrated comparative system. The current review paper fills this gap by presenting a risk-

opportunity analysis framework allowing to organically compare EOR techniques based on governing geomechanical processes, the risks involved, diagnostic indicators and leverages of operational control. To this end, the given review report offers a combined summary of the geomechanical interaction governing EOR operations and reservoir integrity during the process of water, gas, chemical, and thermal recovery methods. The special focus is on pressure-stress coupling, stress-sensitive permeability, fracture and fault stability and coupled thermo-chemo-mechanical effects. Lastly, the review also notes that full coupled reservoir-geomechanics modeling and time-lapse monitoring can be utilized fully to determine safe operational windows that can be used to maximize recovery with the least compaction, caprock failure and induced seismicity.

2. Geomechanical Fundamentals Influencing Enhanced Oil Recovery

The fluid displacement in any EOR operation can be promoted by or hindered by changes in pore pressure, stress distribution, temperature and rock fabric. These processes have a direct influence upon injectivity, sweep efficiency, reservoir integrity and sustainability of production/injectivity in long-term condition. In this section, the basic geomechanical principles, including effective stress, poro-elasticity, and deformation/failure mechanisms of reservoir rocks that prevail in such interactions are reviewed for effective design of EOR projects with risk management.

2.1. Effective Stress

The concept of effective stress, originally proposed by Terzaghi (1925) and subsequently generalized by Biot (1941), denotes the way in which the total stress is divided between the solid skeleton and pore fluid in porous materials. The effective stress can be calculated using following equations:

$$\sigma' = \sigma - \alpha P \quad (1)$$

$$\alpha = 1 - \frac{K_{dry}}{K_s} \quad (2)$$

where σ' is the effective stress, σ is the total stress, P is the pore pressure, α is Biot coefficient, K_{dry} is the dry bulk modulus of the rock framework and K_s is the bulk modulus of the solid mineral grains [6, 25]. According to Terzaghi's principles, when a rock is encountered to the stress, increasing pore pressure leads to effective stress decrease [3]. In primary depletion, the decrease

in the pore pressure, increases σ' , compressing the rock matrix and, in worst case, leading to surface subsidence as was eminently witnessed in the Ekofisk chalk field where surface subsidence of over 10 meters was observed [21]. During the secondary and tertiary recovery processes, the pore pressure is raised thus decreasing the effective stress in the direction of the current stress field [22, 23], which can lead to reopening of the preexisting faults and impacting the permeability or integrity of the caprock as has been observed in CO₂ injection and unconventional reservoir experiments [24-26].

2.2. Poroelasticity: Mechanical and Hydraulic behavior Coupling

Poro-elasticity offers a powerful tool of examining the relationship between the mechanical performance and fluid flow of reservoir rocks [27]. In the case of EOR, in the poro-elastic material, the deformations are not only caused by the mechanical stress but also by the change in the pore pressure. These two sources of deformation act on the solid framework of the porous medium. The inescapable processes also affect not only the mechanical characteristics of the reservoir rock, which may cause compaction and reactivation of faults, but also its hydraulic properties, both due to changes in porosity and permeability [2, 3]. The constitutive equation of poro-elastic materials can be written assuming that they can be described by linear elastic isotropy as follows:

$$\varepsilon_{ij} = \frac{1+\nu}{E}(\sigma_{ij} - \alpha p \sigma_{ij}) - \frac{\nu}{E}(\delta_{kk} - 3\alpha p)\delta_{ij} \quad (3)$$

In which, ε_{ij} is the strain, σ_{ij} is the stress, E is the modulus of elasticity and ν is the Poisson's ratio. In this equation, the influence of the pore pressure on volumetric strain and alteration of the stress in the porous framework can be seen. The effective stress decreases when the pore pressure is increased, and it might result in developing such mechanical instabilities as shear failure, compaction, or fault slippage [28, 29]. Poro-elastic effects in EOR processes can significantly change the geomechanical and flow characteristics of the reservoir. These interdependence effects are critical factors to be considered for predicting the performance of the reservoir enough to make sure its permanence throughout the time [30-32]. In this respect, the major outcomes are:

- Volumetric strain and permeability:

In EOR operations, such as waterflooding, the increase in pore pressure can lead to a reduction in the effective stress, which may alternatively lead to an increase in rock permeability and porosity.

The increase in pore pressure in other structures can increase the dilation of the microfractures or the openings of the existing channels leading to the increased fluid flow capacity [33-35].

- Poro-elastic deformation:

Due to changes in the pore pressure during the EOR operation, poro-elastic deformation of the reservoir can occur, potentially spreading to the overburden and leading to surface level alternations. For example, InSAR, a useful remote sensing method, detects such surface deformations in relation to the activities of hydrocarbon production and injection. Incorporating poro-elastic models into the InSAR observation allows one to correlate the surface pattern of displacements with the change in subsurface pressures and redistribution of stress. The coupling has been used with success in mature reservoirs e.g. those in the Permian Basin where long-term fluid removal or injection has caused large pore pressure changes that cause observable surface deformation [36].

- Shear failure and fault reactivation:

The reduction effective stress in EOR operations may result in shear failure or re-activation of the preexisting faults [37, 38].

2.3. Deformation Processes: Elastic and Inelastic responses

In all the steps of EOR, it is essential that the operators measure how the rocks within the reservoir react to changes in the stress conditions because the rocks can be either elastic or inelastic in deformation. These are the key processes to know to be able to maximize recovery, injectivity management, and geomechanical integrity [22, 39]. Elastic deformation of the reservoir rocks occurs under low to moderate stresses and the resulting strain is totally reversible. The elastic response is controlled by Hook law and can be determined by the elastic properties of materials i.e. Youngs modulus and Poisson ratio [3, 22, 40, 41].

3. Geomechanical Impact of various EOR techniques

3.1. Compaction, Subsidence Development and Fracture Reactivation in Waterflooding

Waterflooding is one of the most prolific methods used in EOR to maintain pressure in the reservoir, forcing oil towards the wellbore. As the pore pressure increases during waterflooding, the effective stress in the reservoir becomes less, which may cause rock compaction, layer sinking

on top of the reservoir as well as reopening of old cracks or faults [3]. A typical example is the Ekofisk chalk reservoir, where ongoing seawater injection has resulted in a maximum rate of subsidence of 12 cm per year [42].

The analysis of Mohr circles revealed that even after secondary recovery, the reservoir was still mechanically stable and had a large failure margin. However, interestingly, the rotation of the principal stresses created an imbalance between the variation of σ_1 and σ_3 leading to the elliptical movement of the circle of Mohr and increased stress anisotropy under unsteady reservoir conditions [43]. The geomechanical evolution of the stress states of the rock in the primary depletion followed by waterflooding is depicted in Fig1. The production process on maximum principal stress (σ_1) instead of on the minimum stress (σ_3) augments the effective stress and extends the Mohr circle. This leads to more radius increase compared to a lateral movement. In the secondary waterflooding, the maximum and minimum effective stresses gradually reduce as the pore pressure increases until the Mohr's circle is crafted, despite the fact that the stress state is usually still a long way below the failure envelope. Experimental and numerical measurements have shown anisotropic redistribution of the stresses which is expressed through rotation of the major stress axes and elliptically shaped Mohr paths [43].

These results illustrate the necessity of adding the interaction of anisotropy of stresses and the evolution of pore pressure to geomechanical studies and models [44, 45]. All these considerations highlight the reality that injection rates and pressures have to be optimized to minimize the chances of excessive fault reactivation and long run stability in the waterflooding operation [6, 46, 47]. Recent studies show that the injection of smart water in chalk or carbonate formations has the potential to enhance the oil sweep efficiency while reducing the rate of mechanical weakening. Talebian et al. (2021) demonstrated that the processes of an ion exchange (replacing Ca^{2+} in the rock and replacing SO_4^{2-} in the water) change the wettability of the rock, but they also diminish the grain-to-grain bonding and allow further compaction. The conceptual flow chart of the chalk and carbonate reservoir of water based EOR linking chemical and mechanical pathways is revealed.

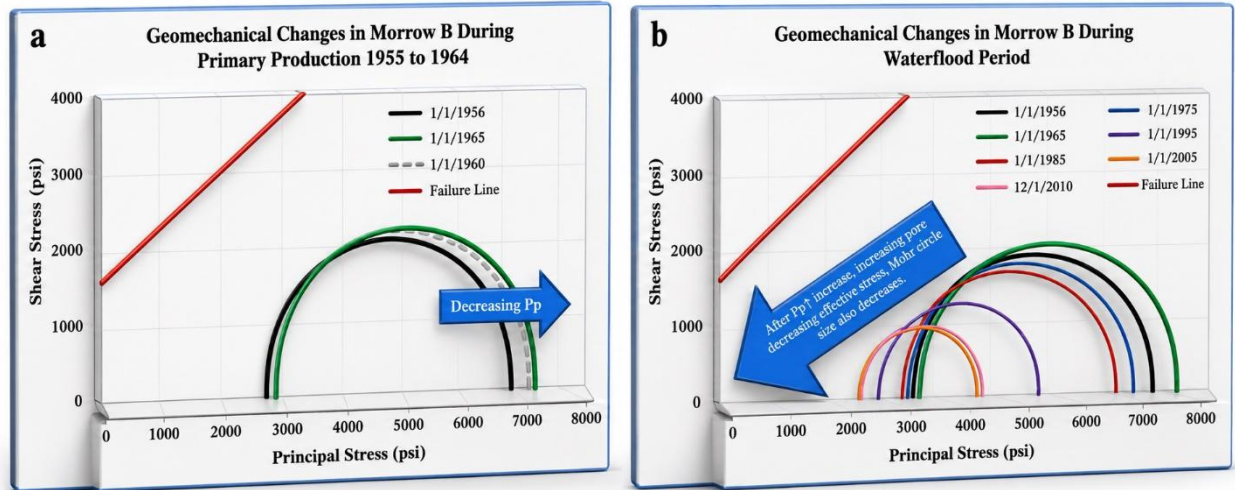


Fig 1 Evolution of stress state in Morrow B during (a) primary depletion and (b) waterflooding, illustrating pore pressure effects on effective stress and Mohr circle evolution (adapted from Marcia McMillan [43]).

Natural depletion leads to compaction and loss of porosity which may progress to formation and subsidence damages is summed up in the Fig2 The interaction between smart water and seawater injection can be indicated as a combination of mechanisms, where dissolution of minerals, ion exchange (Ca^{2+} replacement, diffusion), and wettability change contribute to a higher displacement efficiency but also decrease the grain-to-grain cohesion and increase compaction by chemo-mechanical processes [48, 49]. The two-fold increase in the latter would represent an operational window over which geomechanical threat would offset recovery gains. Therefore, to narrow the model parameters and ensure the safety of the water-based EOR in the stress-sensitive carbonate fields, strong calibration based on zeta potential, pre- and post-UCS test, and stress-dependent permeability analysis is needed to enhance well flooding by decreasing the fluids contacting the rock [16, 50]. Fig2 presents the workflow illustrating the coupled impact of smart water injection on wettability alteration, oil displacement, mechanical weakening, and reservoir compaction.

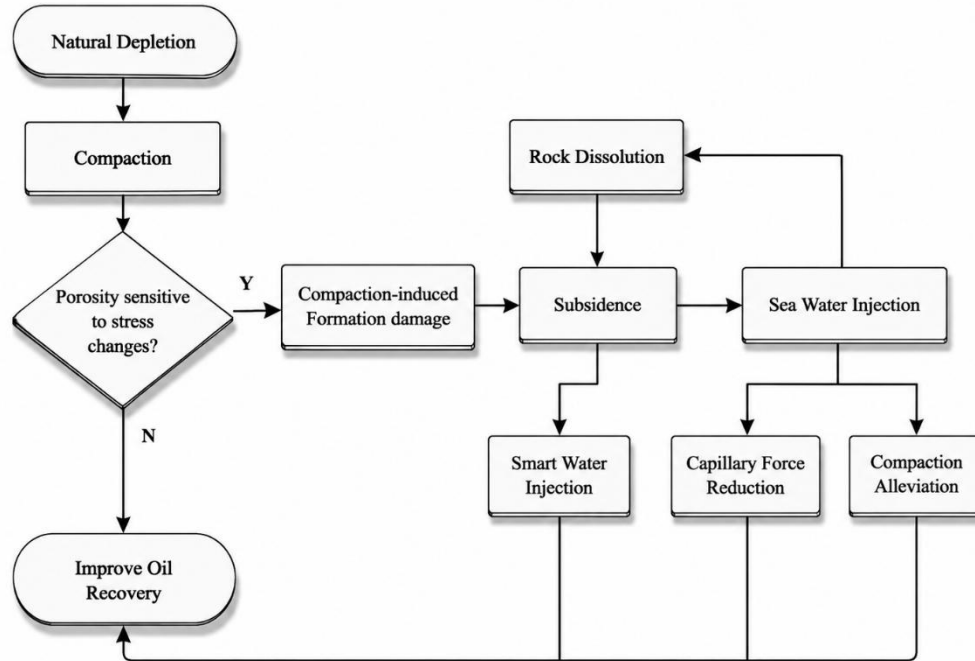


Fig 2 Conceptual workflow illustrating the coupled impact of smart water injection on wettability alteration, oil displacement, mechanical weakening, and reservoir compaction (adapted from Seyedeh Hosna Talebian et al [16].

3.2. Chemical Enhanced Oil Recovery (CEOR)

Chemical enhanced oil recovery (CEOR) methods are routinely employed in the field to change fluid–rock interactions and fluid mobility, such as polymer flooding, surfactant flooding, and alkaline–surfactant–polymer (ASP) flooding. These processes, however, can also have significant geomechanical and geochemical impacts on the reservoir, such as changes of pore pressure, effective stress and rock/fluid interactions [50, 51]. The more viscous the polymer solution, the more resistant to flow it will be and the higher the pressure will need to be to achieve a desired injection rate. These ones may create high stress changes around the wellbore, especially in weak, unconsolidated or naturally fractured formations. These stresses can cause shear failure, sand deformation or fracture reactivation, which can affect wellbore and formation integrity [52–54]. Also, the fluids in CEOR can have a physical/chemical effect on the reservoir rocks. Low salinity water may result in clay swelling, for instance, and reactive water may cause mineral dissolution. Clay-rich or carbonate formations have specific effects that can alter pore structure, permeability and local stress conditions and are of particular importance. These changes also can cause compaction or reactivation of pre-existing fractures [55, 56]. The potential for microfracturing and preferential leakage pathways in the caprock may be further enhanced by injection-induced

effective stress reduction in the caprock in heterogeneous reservoirs. Thus, integrated hydro-geomechanical modeling frameworks must take into consideration chemical reactivity, rock mechanical properties, and injection conditions all at the same time in order to maximize recovery while ensuring geomechanical integrity [53, 57].

A representative study by Khodaverdian et al. has been conducted to Fig3 show the geomechanical effects of polymer flooding in unconsolidated-sand formations. They conducted geomechanical simulations, which indicated that by three months after starting the polymer injection, the minimum effective stress in the area surrounding the injection fracture was lower than 1.5 MPa due to continued injection. As a result, a distinct shear failure zone formed around the fracture and slowly advanced towards the production well as the injection increased. These results show that by using high-viscosity polymer injection, the effective-stress state of the formation can be altered and may adversely affect fracture containment and formation integrity [52].

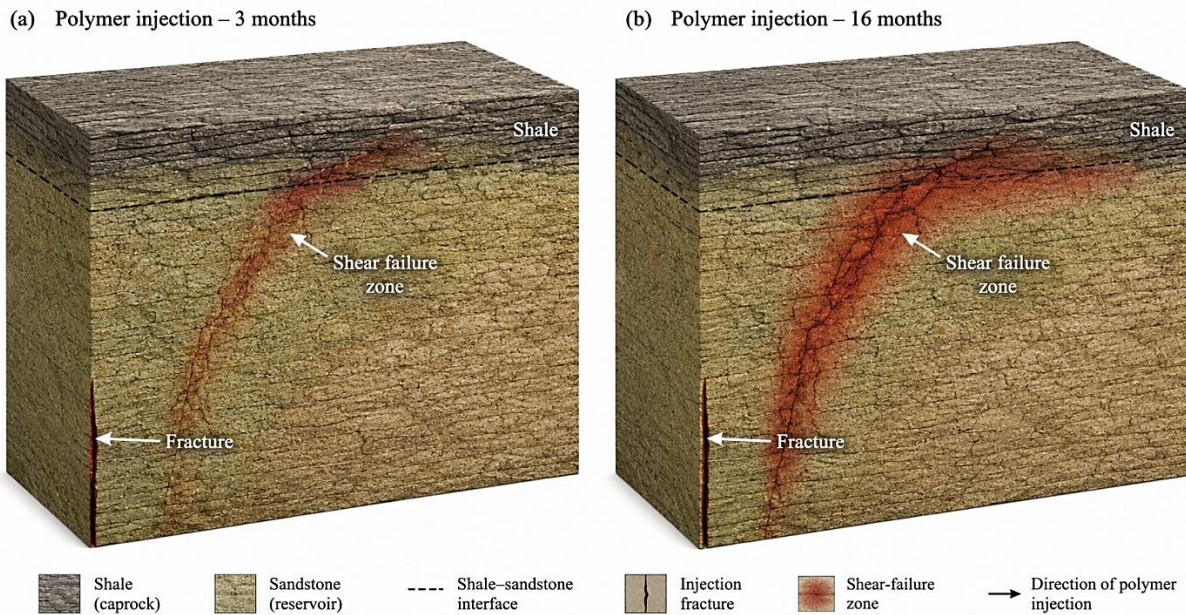


Fig 3 Predicted formation failure after (a) 3 months and (b) 16 months of polymer injection, showing the development and progression of the shear-failure zone around the injection fracture (adapted from Khodaverdian et al [52]).

3.3. CO₂ and N₂ Gas Injection

The use of CO₂ and N₂ as the gas injected in EOR is a common approach because it raises the efficiency of the sweeps, the degree of miscibility, and the pressure of the reservoir. Nonetheless,

there are also intricate geo-mechanical reactions (e.g., increase in pore pressure, thermal stresses, and interaction of fluids and rocks) brought about by gas injection. The increase in pore pressure in the instance of gas injection causes the effective stress to reduce and can possibly reopen any pre-existing fractures or faults, especially in those formations that are on the edge of reaching a critical stress state. Besides, carbonate minerals including calcite or dolomite can react with CO₂. The rock substances can be chemically modified and lose their cohesion. Coupled pore-pressure increase, thermoelastic stresses and geochemical rock–fluid interaction can cause significant geomechanical responses during CO₂ injection. The changes in pore geometry, rock stiffness, and changes in the evolution of permeability due to dissolution of carbonate minerals, such as calcite and dolomite, affect permeability. For stress-sensitive formations, these coupled properties can lead to fracture closure, permeability decrease, fault reactivation, and caprock integrity hazards. Additionally, injection of CO₂ can cause thermoelastic stress perturbations that can cause tensile microfracturing in regions near the wellbores and critically stressed discontinuities. N₂ is chemically inert but it is frequently found that higher pressures are necessary for minimum miscibility pressure (MMP), and that this can cause significant stress perturbations around the injection zone. Higher injection pressure can lead to tensile fracturing, fault reactivation, casing deformation, and injection induced seismic activities, especially in mechanically weak and/or heterogeneous formations [6]. Fully coupled THM models should be implemented in order to assess and reduce these risks. As an example, Tian et al. (2019) applied a THM model to model gas injection in nanopore-constrained tight reservoirs, and found that development of stress-sensitive porosity and permeability is significant to recovery performance. Equally, Bataee et al. (2014) developed a water-Alternating-Gas (WAG) injection model that incorporates stress feedback and redistribution of dynamic pressure, which has a great impact on the porosity distribution and production outcomes. These papers have shown that inclusion of THM coupling in predictive modeling is important especially in tight and geomechanically complex reservoirs [17, 58]. As Baig et al. (2025) emphasized, the safe containment of CO₂ is controlled by the combined action of mechanisms of mechanical and solubility trapping (Fig4). These observations highlighted the importance of geomechanical monitoring for caprock integrity assessment and injection management [19].

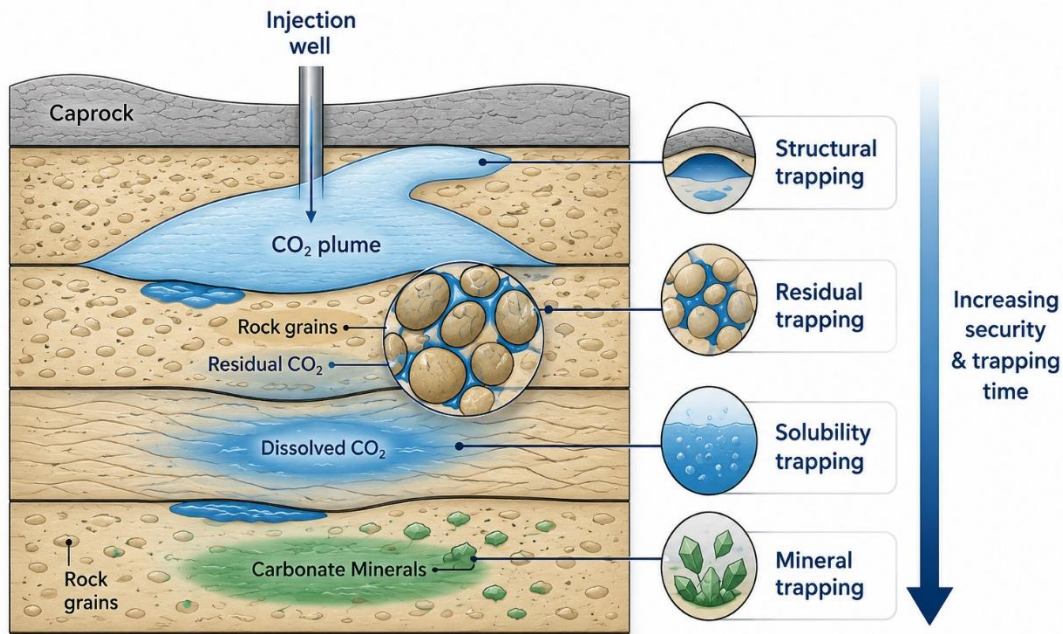


Fig 4 Interaction of CO₂, brine, and rock during the CO₂ trapping (adapted by Abdul Rehman Baig et al [19]).

3.4. Thermal EOR

Steam injection, cyclic steam stimulation (CSS), in-situ combustion (ISC), and steam-assisted gravity drainage (SAGD) are widely applied thermal enhanced oil recovery (TEOR) methods for improving oil mobility, particularly in heavy-oil reservoirs. However, the application of thermal recovery processes can induce substantial geomechanical responses because of steep temperature gradients, thermoelastic deformation, and coupled thermo-hydro-mechanical (THM) interactions. Rapid heating produces non-uniform thermal expansion of the reservoir matrix, particularly in formations characterized by mechanical anisotropy or heterogeneous mineralogical composition. The resulting differential stresses may exceed the tensile strength of the rock and initiate microfracturing [59].

Thermal expansion, however, is not the only mechanism governing thermally induced deformation. Shear dilation can play a significant role in unconsolidated formations [60]. Shafiei and Dusseault reported that steam injection can induce substantial dilation of sand grains, resulting in an increase in vertical permeability to more than 10 Darcy. Such deformation not only facilitates

gravity drainage but can also produce significant surface uplift. In some SAGD¹ operations, total surface uplift has exceeded 310 mm, with only a small fraction attributed to thermal expansion [61].

These thermally induced deformation mechanisms can also increase the risk of mechanical failure in the reservoir, caprock, overburden, and wellbore. CSS involves repeated heating and cooling cycles, which can produce stress reversals and thermal fatigue, potentially promoting the reactivation of pre-existing fractures or the development of new fractures. Similarly, the intense pressure and temperature gradients associated with localized combustion in ISC can amplify shear stresses and compaction in mechanically weak zones. These processes may ultimately compromise caprock integrity and wellbore stability and increase the potential for leakage or sand production in poorly consolidated formations [61-64]. Among all thermal enhanced oil recovery methods, hot water or steam injection processes are the most preferable due to their simplicity, which results in mostly predictable outcomes [65].

The effects of nanopore confinement and stress-dependent rock properties are captured in the phase-equilibrium calculation using a coupled thermodynamic–geomechanical framework as illustrated in Fig5. The calculation starts with the governing equations and an initial guess of the phase composition and phase fraction (using Wilson's equation). The Rachford–Rice equation is then solved iteratively along with the Peng–Robinson equation of state (PR EOS) to get the phase-equilibrium state. Under nanopore confinement the pore radius is considered as a function of the effective stress (effective stress) while the porosity and permeability are calculated based on the stress. Interfacial tension (IFT) between the liquid and vapor phases is then used in the Young–Laplace equation to calculate the capillary pressure (P_c). The capillary pressure correction is then added to the phase equilibrium calculation, which accounts for the effect of the confinement of the pore scale on the phase behavior. Then, the calculated secondary variables are assessed against the convergence criterion. If the condition is not met, the variables are reinserted into the governing equations for the next iteration, otherwise the solution is considered converged.

This coupling serves as a convenient model for the study of phase behaviour in low permeability and nanoporous media where the capillary pressure, interfacial tension, pore-size variation and

¹ Steam-assisted gravity drainage

stress dependent porosity and permeability can interact strongly. Therefore, the combination of nanopore confinement and stress dependence of rock properties into equation-of-state (EOS) and thermo-hydro-mechanical (THM) calculations can yield a more physically realistic description of fluid–rock interaction for reservoir conditions under confinement [17].

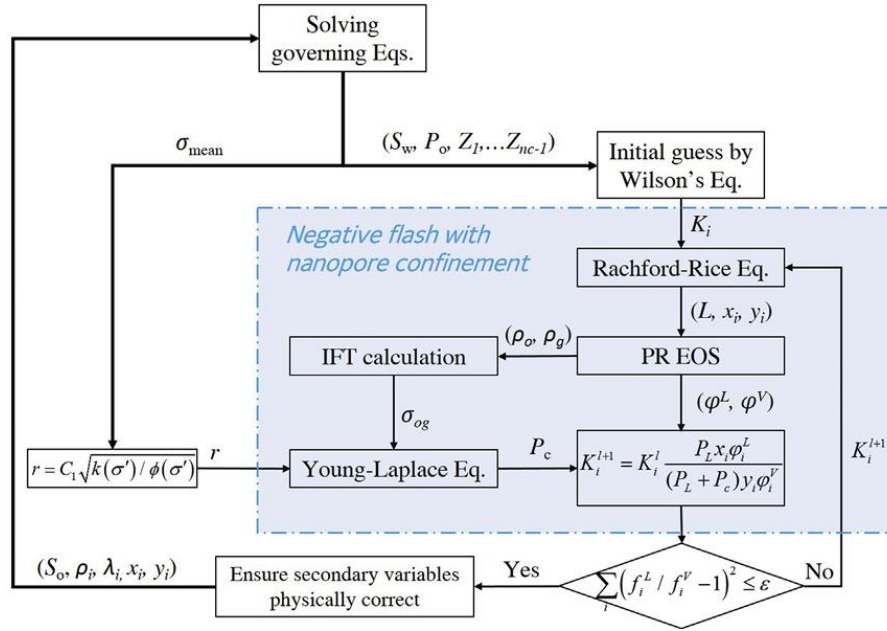


Fig 5 Coupling of nanopore confinement and geomechanics in VLE calculation (adapted from Ye Tian et al [17].

The geomechanical response of the reservoir during SAGD operations is governed by a series of coupled thermo-mechanical and flow processes, as illustrated in Fig. 6. The thermoelastic response of the reservoir with steam injection is shown in Fig (a). Thermal expansion caused by the heat leads to significant redistribution of stress and to a rise in horizontal compressive stress around the heated region, this being limited by the cooler surrounding formation. These stress changes, together with the advancement of the thermal front, will lead to the formation of high deviatoric stresses in front of the steam chamber [61].

The evolution of the SAGD steam chamber and the gravity drainage mechanism are illustrated in Fig (b). The steam rises from the ground by gravitational thermal segregation, flows laterally in the reservoir and then turns to water and the condensed water and the hot oil travels towards the production well. Shear dilation leads to increased vertical permeability and a gravity-driven flow, which is strongly affected by this [61].

Fig (c). shows the shearing and dilation ahead of the thermal front, caused by the thermal stress. The localized stress change may cause the local shear yield condition to be violated, thus resulting in shear deformation and overall volume increase of the sand. This dilation creates more space for the pores and makes them more permeable, and may also destroy thin clay layers and bedding plane barriers, allowing greater vertical permeability [61].

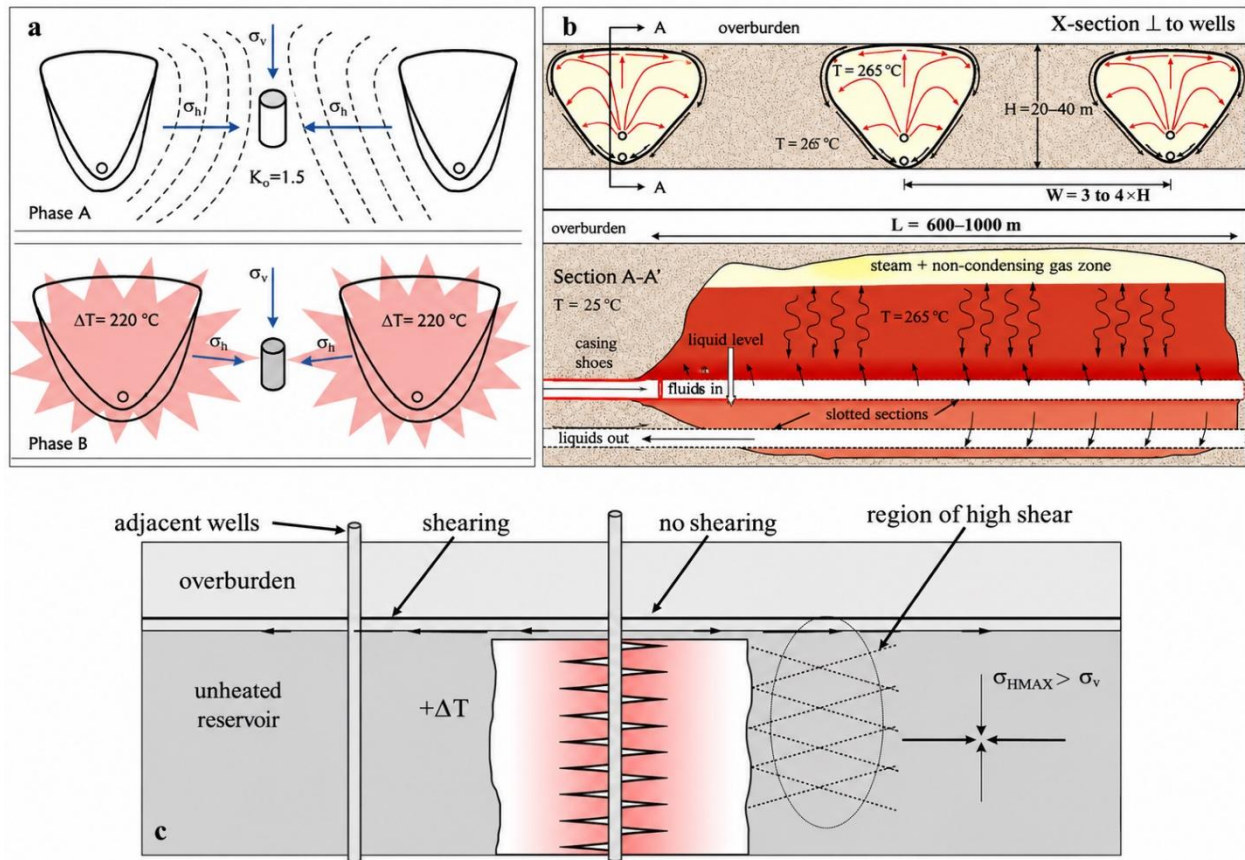


Fig 6 Geomechanical mechanisms governing thermal recovery by SAGD: (a) thermoelastic expansion and stress redistribution induced by thermal loading, (b) steam-chamber growth and gravity-driven drainage, and (c) stress concentration and shear-induced dilation [61].

Recent THM analyses undertaken in the scope of cyclic steam injection have demonstrated that dilation/compaction thresholds are important parameters. These thresholds are also to be looked at in regards to the behavior of the rocks as chunks under the conditions of injection and off-loading that include the stiffness of the rocks. Fig7 This is significant with regard to vertical deformation and reservoir compaction due to various thermal loading conditions [66].

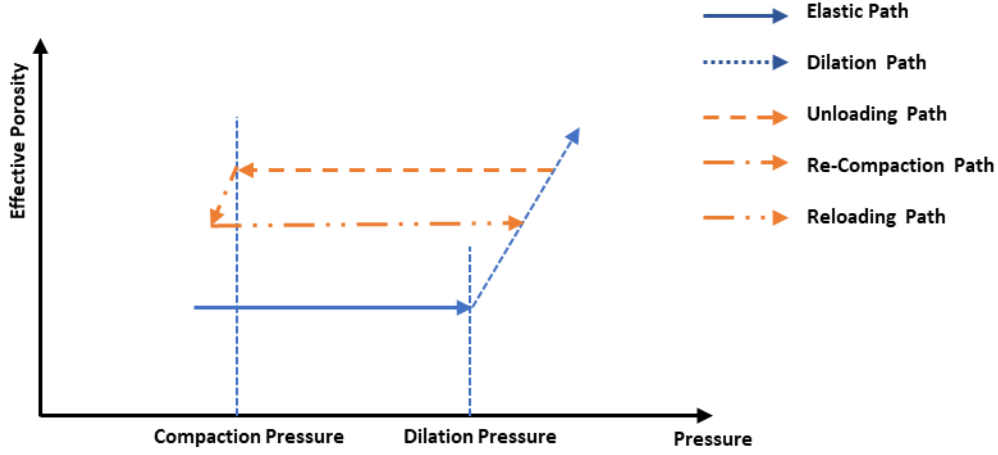


Fig 7 Conceptual hysteresis model for stress-dependent Young's modulus during cyclic steam injection, based on dilation and compaction pressure thresholds [66].

Temperature changes induce thermal strains that lead to thermoelastic stresses (e.g., Hojka et al., 1993) which can result in rupture or shear (Dusseault et al., 1988), accompanied perhaps by dilation (Dusseault and Rothenburg, 1988). Stresses in the elastic range can be computed by incorporating thermoelastic rock volume changes using the equations of fluid-saturated, poro elastic solids developed originally by Biot [2, 67, 68]. Dusseault (1993) proposed a simple first-order approximation based on a uniform, homogeneous, flat-lying, laterally extensive reservoir subjected to uniform heating (Fig. 8), where an assumption of zero lateral strain can be justified. According to Hooke's law and Terzaghi's effective stress principle, the following equation can write:

$$\varepsilon_i = \frac{1}{E} [\Delta\sigma'_i - \nu(\Delta\sigma'_j - \Delta\sigma'_k)] + \beta\Delta T; \quad \Delta\sigma'_i = \Delta\sigma_i - \Delta p$$

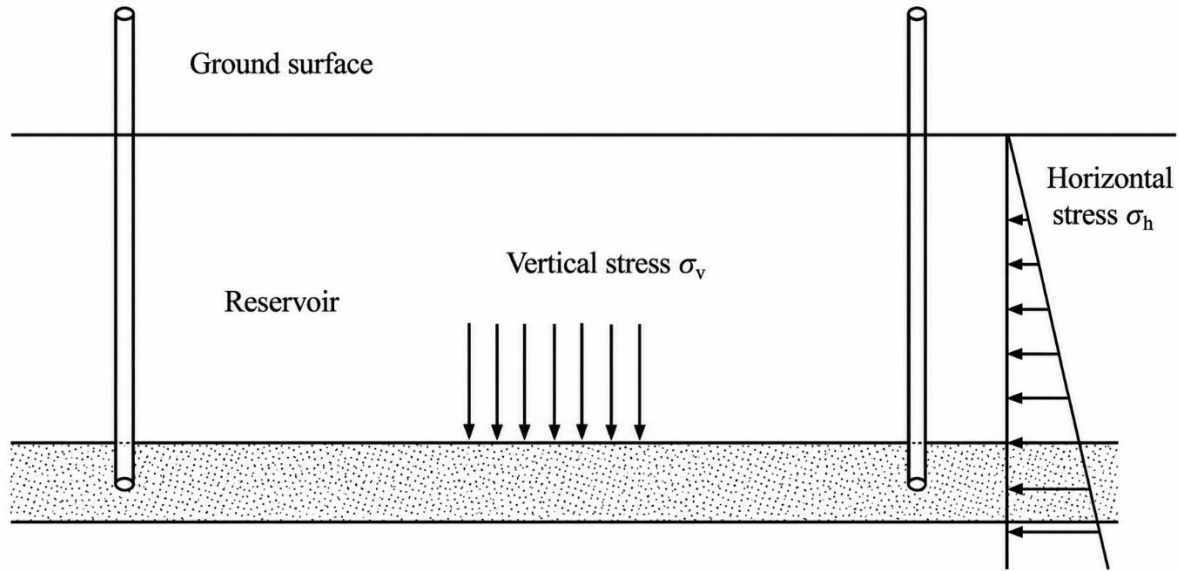


Fig 8 Schematic model of stresses in a laterally extensive reservoir (adapted from Dusseault, 1993 [69].

4. Fractures and Faults in EOR processes

The faults and fractures in the formations are important and inseparable components of the reservoir systems, which have a high influence on the efficacy of EOR actions. It is important to conduct a quantitative evaluation of their mechanical response, changes in permeability, and reactivation possibilities due to dynamic stress situations to ensure long-term reservoir stability and fluid retention. Injection-induced changes in pore pressure, coupled with natural fracture networks and faults, can frequently control injectivity, as well as the sweeping quality and the threat of induced seismicity and/or the failure of the caprock [17, 38].

4.1. Natural Fractures

Natural fracture systems are important to the process of subsurface fluid flow, particularly in carbonate reservoirs in which the rock is highly low-permeability matrix. The mechanical mechanism of the fractures in the presence of various stress regimes can significantly influence the conduction properties of the fractures throughout the reservoir life [69, 70]. The fracture aperture and connectivity vary with the stresses exerted by the production and can lead to a significant change in flow with time. There is a need to know not only the static characteristics such as the geometry, spacing and shape of the fractures but also the responses of the static behavior to the dynamic parameters such as stress sensitivity, closure pressure, and reactivation potential [71]. The Fig9 is a schematic displaying hierarchy and distribution of fractures in a

naturally fractured reservoir with the major (black), medium (red), and minor (green) fractures, and their contribution to the permeability and flow connectivity [71]. The diffuse fracture is normally presented in the core information of the rocks that consist of several mineral make-ups. They take place in the rocks in which the rate of change is intense as in the top and bottom of the reservoirs or in the cemented layers [69, 72]. Their opposite nature is mostly similar to the major stress in the area (e.g., NNE-SSW). Some of the aspects associated with their shape include the manner in which they were formed, the openness that the rocks took, the density of the layers, and how they changed following the concept. Diffuse fractures, even on a sub-seismic scale, may be important fluid conduits or barriers during both thermal and stress cycling in EOR processes [73-75]. Another case by Shekhar et al. (2019) shows this trend in a carbonate layer in the deep water of Abu Dhabi. Diffuse fractures were identified as having a natural fracture hierarchy in high-intensity fracture corridors, which were shown to have stratigraphic control and structural orientation. The consequences of such exhibits were uneven movements of water and premature breakthrough of water, which suggests stress-induced reactions and formation of permeability routes [76, 77]. The addition of time-varying production data to define fractures enhanced fluid migration and pressure transmission simulations through the illustration of the significance of stress-induced variations in fracture conductivity [73].

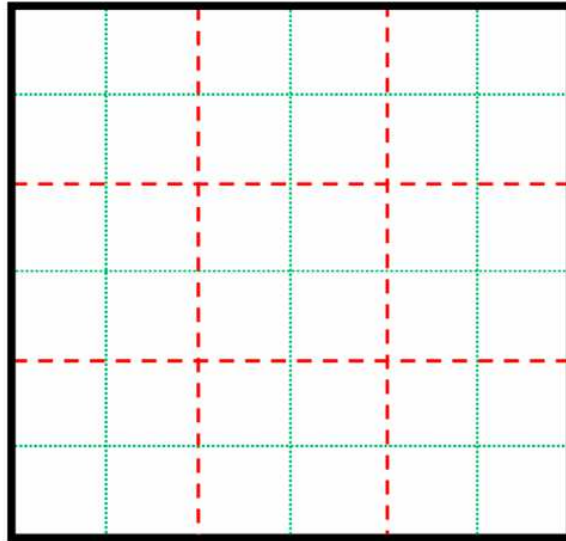


Fig 9 Schematic representation of fracture hierarchy and distribution in a naturally fractured reservoir (adapted from Riyaz Kharat [72]).

4.2. Fault Reactivation and Induced Seismicity

Faults can become active again during EOR process due to various factors that occur one after another. These include the build-up of pore pressure, the change in original stress of rocks, the location of the fault, and the fault's slipperiness. In the investigate sites of the Sichuan Basin, seismic signals revealed that the fault zone may continue to move even during the shutdown of the well, which may denote the fault delayed rupture (Zhang et al., 2019). What we find between when seismic signals are produced when water is injected into the ground, and when the subsequent earthquakes take place when the injection is ceased are consistent with the rate-and-state theory of friction on Earth [78]. This theory is used to explain the change of slip with time as a result of injection stress. It is demonstrated by simulations that the total water used is a more accurate predictor of a fault slipping or the change of form of a casing than the current amount of water used. The fact that the injection has been done matters in regard to the probabilities of a quake [79]. The main importance of fault transmissivity and the time-dependent effect of THM coupling is also stressed by Wassing et al. (2021), who emphasize the importance of paying attention to the transmissivity of faults and the effect of changing this parameter at a certain period of time regarding the issue of whether a fault would re-activate and lead to a quake or not. Rather, the models demonstrate that stress in the interior of a low-permeability fault may increase even after injection is discontinued, which may lead to an earthquake in the future. This implies that, when it comes to deciding the geomechanical models, it would not only be the loading of the fault and its fluid content, but rather the implications of the fluid pressure to creeping fault zones and the sensitivity of the stress path, especially in natural fractured reservoirs. Failure to incorporate such effects will result in the risks of quakes from injections being significantly underestimated [80]. Building on this point, we can apply our understanding of CO₂ storage to gain better insight into the movement of faults after prolonged fluid is forced into them [26, 81]. Rutqvist et al. (2016) performed a set of combined THM simulations. These prove that initiation and propagation of fault slip depends not only on the alteration of the pressure in the reservoir but also on the measures of heterogeneity in the fault zones, the direction of the stress, and rate-weakening in faults [6]. This work has demonstrated that despite the fact that the results used in this work do not reflect that any seismic signals have taken place, there are cases of slip in the absence of stress, and stresses that changes the ease with which fluid flows through the rock. These alterations may reveal the seal layer especially in hard rocks or the formations in layers [82]. It is also demonstrated in the work that local differences in stacked layers of sand and clay may concentrate the stresses to retard the

advancement of faults at the expense of broadening the magnitude of a fault slip [6, 82]. The injection zone in relation to the fault is also a key factor in its outcome. When the areas of high pressure are near the back wall of the fault, the high-pressure zone has a greater capacity to alter the stress of the rocks in the layer of rock [6].

4.3. Injection Parameters considering Fractures

The fracture behavior subsequent to the injection of fluids is highly dependent on the timing and the sites at which the important parameters of injection rate, pressure, temperature, and fluid composition are considered. According to experimental investigation and coupled THM studies on the EOR and EGS, high injection rates have been known to cause rapid fracture propagation. On the other hand, more complex fractures are formed through progressive shear and opening mechanisms in slower or cyclic rate injection [6, 83].

In cases where injection is done in a cycle, like CSS or CO₂ huff-and-puff, the use and removal of the weight of the load changes the size of the fracture by thermoelastic contraction and expansion, and may cause the permeability to be different or the stress to be ‘remembered’. These cyclic ways of stressing will create either a loss of open space or, instead, the fracture may open steadily when the stress is less than the amount needed for slip [79, 84]. The form of the fracture surfaces and the ruggedness of their contacts do not just happen to be the reaction to injection pressure alterations. At a low level of stress that causes slip, the asperities would tend to obstruct the slip and increase the difficulty of slip; whereas at a high level of stress where slip may occur, small fractures would rapidly form and could cause a sudden alteration in the flow of the fluid. Also, high-pressure injection can form additional fractures that can by-pass the areas of interest or create difficulties to the wellbore in case they are not observed [79, 85, 86].

The permeability variation with stress models, cyclic THM tests, and consideration of the observed fractures in the field have to be incorporated in the design of the injection plan in the EOR projects to make sure that these factors are taken into consideration. The follow-up of developing fractures and the modification of the injection regulations to enhance better sweep and circumvent geomechanical-related risks can be achieved via the use of real-time monitoring technique, including micro seismic imaging or tiltmeter arrays, in low-permeability zones (where the fractures can be induced through heating) [26, 79, 87, 88].

4.4. Thermally Induced Fractures

Thermal fractures, as they are often referred to, or near-wellbore thermal fractures are human made features that develop as a result of thermal gradients that are created within the rock around the injection wells. When a cold liquid like water or steam condense is conjectured into warmer rock, the cooling effects result in the rock contracting. The tension thus imposed on the rock by this contraction may be greater than the tensile strength of the rock, particularly in brittle rocks such as compact limestones. Consequently, radial or axial thermal fractures may form near to a wellbore[61, 89]. The fractures are widely found in the borehole wall rocks and their incidences are usually higher than the core samples [90]. Special attention is paid to thermally induced fractures in a low-permeability zone since this problem can significantly alter near-wellbore permeability and lead to uncontrolled fluid flow [91]. Where there is some lack of seismically imaged faults, early breakthroughs can be ascribed to act of thermal fracturing [73]. Moreover, thermally induced cracks may grow and connect to the pre-existing natural fracture systems forming intricate fracture networks which are hard to characterize. These interactions being highly complicated, they usually punch through in abnormal production or injection patterns, since these would not be usually captured in image logs. An insight into the phenomenon and growth of such fractures is important to construct fluid flow models correctly and to evaluate the geomechanical risks of thermally stimulated, cavernous reservoirs [92-94].

4.5. Fractured Reservoir Stress-Permeability Coupling: EGS System Insights

Although it is not used to achieve the same objectives, both EOR and EGS have one important geomechanical process that determines the fluid movement and stress alterations occurring in fractures in the earth. Experience with EGS tests and field work can provide an insight into stress-sensitive fracture behavior useful in EOR particularly with respect to the joint effects of heat, pressure, and rock mechanics [95-97]. One of the most important lessons of EGS research is the non-linear correlation between the permeability and the effective stress. Closure of fractures under increasing confining pressure is commonly observed in crystalline low-porosity rocks, and also in tight carbonate and sandstone oil and gas reservoirs applied to EOR. This observation dictates that we consider permeability as a stress-dependent characteristic especially on cyclic injection, which varies the fracture [83, 97, 98]. The data also show that cyclic stress causes variation in the roughness and contact area on the fracture surface, leading to an irreversible change in the

permeability of a hysteretic nature. Such things happen in polymer and thermal EOR, and injection results in dilation, followed by partial closure, which modifies the transmissivity of a fracture. It should then be noted that fracture conductivity must be regarded as a variable of stress level and path, so it needs to be calibrated in field in nearly real time [99, 100]. Tests in step-rate injection and pressure fall-off have played a major role in EGS in identifying the stress-path-dependent nature of fractures. A very important finding is that there are dilation thresholds: once crossed, the fracture demonstrates a different, irreversible, apertural increase similar in mechanism to what occurs in steam and gas injection in EOR [84, 101, 102]. The other important observation made by EGS tests is that the stiffness of rocks is never repeatable that is demonstrated by the decline in Young's modulus which never fully recovers once the load is withdrawn. This approach to changing the properties of a given material can have a substantial effect on thermal EOR, in which the rock is heated and cooled in cycles. This effect is also illustrated in Fig10 which shows testing on hot fractured granite. The plot was drawn over time as the pressure was added and the rock slowly gained a strain over a given period and this resulted in rock failure. The crack propagation was observed as the strain gauges measured the crack propagation during the loading, thus, the crack propagation could also be confirmed using the field tests, where hot water is being injected and cumulative creep in shearing and incremental strain softening during the cyclic load event during the repetitive load cycling, which agrees with the rate and state concept of friction and pressure diffusion[103]. This implies that fault slip may be delayed even when an injection is stopped. The control measures, which have been proposed, are the limitation on the magnitude of ramps, diagnostic step-rate tests, the real-time observation of geodetic/micro seismic to make sure that the stress paths are not greater than the critical dilation/slip paths [83, 97].

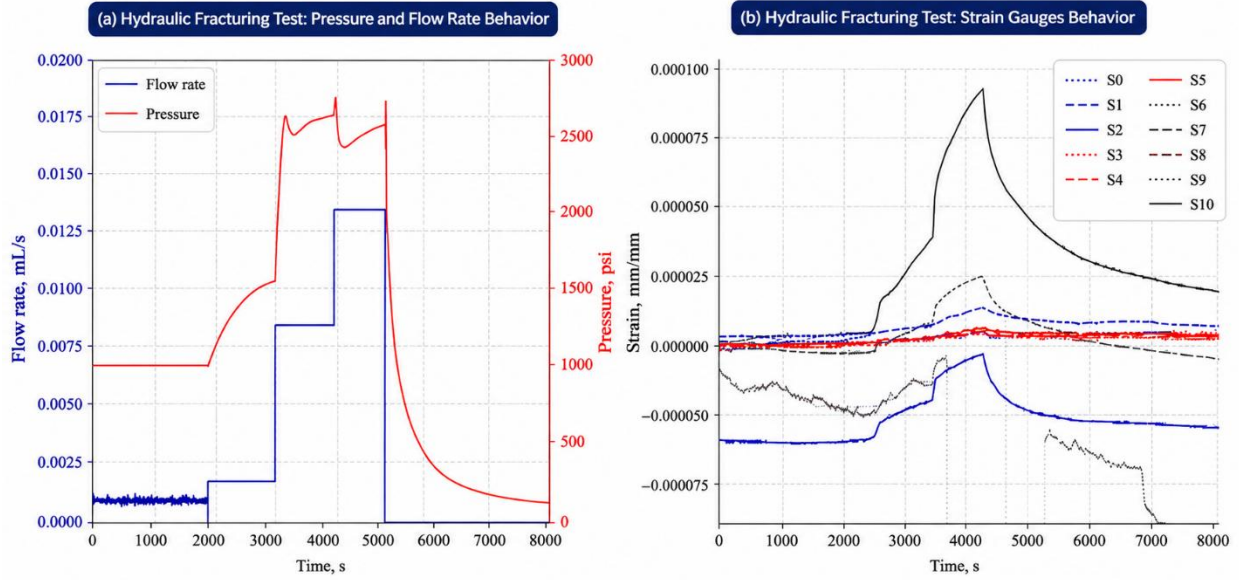


Fig10 Cyclic injection-induced extensional strain in fractured granite under high confining stress, demonstrating shear stimulation and stiffness degradation (adapted from Villaquiran Vargas et al [98]).

5. Geomechanical EOR Modeling and Simulation

Geomechanical modeling is no longer an auxiliary diagnostic instrument but is a part and parcel of EOR planning—mostly in CO₂ EOR operations [104]. These models are finding more applications in optimization of injection strategies, better assessment of reservoir stability, and better risk management in the variable stress conditions [105]. Geomechanical simulations also give insight into the critical interactions involving THMC processes and permit much more predictive and adaptive reservoir management regimes because these processes are coupled between subsurface mechanical behavior and flow and thermal [106-108].

5.1. Semi-Coupled and Fully Coupled

Permanent perturbations in the stress field would occur in the course of the injection process due to the build-up of pore pressure during CO₂-EOR operations, which requires that fully coupled THMC simulations be used [6, 109]. To illustrate that such a model is to be integrated into the probabilistic risk-assessment models, such as NRAP-Open-IAM, and new monitoring instruments, such as the use of InSAR-based surface deformations maps and 4D seismic surveys (Baig et al., 2025), thorough assessments are obligatory [110, 111]. This jointness enables the predetermination of injection pressures, reacts swiftly to any caprock integrity issues and is able to make the long-

term movement of the CO₂ plumes in the atmosphere, through the use of traditional processes [19, 112]. Classical approaches frequently make use of semi-coupled approaches, with reservoir simulators generating pore pressure and saturation fields, and feeding them to geomechanical ones. Elyasi et al. (2016) applied it to ECLIPSE and ABAQUS and proved that it was able to simulate the development of stress during the CO₂-EOR process. However, they noticed some flaws in the feedback effect and more integrated models are required. Fully coupled THMC simulators, including TOUGH-FLAC and COMSOL are interactive and find the flow, heat, and mechanical equilibrium together and give superior predictions of the changes in permeability and redistribution of stress even in cyclic injection [113-116].

Mechanical deformation of the reservoir and surrounding rock considerably affects the behaviour of fluids and has a significant role throughout the primary, secondary and tertiary oil recovery processes. The fluid flow and geomechanics governing equations need to be solved in a coupled manner to correctly capture these coupled processes, which is often done through either fully coupled or partially coupled numerical approaches. Partially (staggered) coupled approaches solve the fluid flow and geomechanical system separately, and exchange relevant state variables iteratively at specified time steps. The use of this strategy is general because the fluid flow processes normally include higher temporal resolution (days) while the geomechanical response evolves over a much longer time scale (months) [117, 118]. In addition to the time step flexibility, partial coupling is convenient to implement different computational grid size and grid spacing. The flow simulator includes only the reservoir whereas the geomechanics model may extend further in the lateral and vertical directions. Hence, the flow spatial domain is typically a subset of the geomechanics domain. In linear-elasticity models, below equations can be used to update permeability and porosity once the total volumetric strain, ε_v , is updated.

$$\phi^{n+1} = 1 - \frac{(1-\phi^0)}{\varepsilon_v} \quad (4)$$

$$k^{n+1} = Ae^{B\varepsilon_v} \quad (5)$$

Where ϕ^0 is the initial porosity, ϕ^n and k^n are the porosity and permeability values at time -level n , and ϕ^{n+1} and k^{n+1} are porosity and permeability values at time -level $n+1$. A and B are coefficients specific to the formation of interests, and can be determined by experiments [15, 117, 119].

5.2. Fractured Reservoirs

Fractured and faulted reservoir modeling is important in EOR projects [120, 121]. There are discrete fracture models and interface elements, which can be explicitly modeled to explicitly model the changes in fault-slip during dilation and permeability [109, 122, 123]. Schmitt and Minderhoud (2022) showed that the measurement of localized pore pressure increases can also reopen faults before the formation of hydraulic fracturing pressures, which causes measurable uplift. Their study highlights the significance of fault mechanics of EOR risk analysis [124].

5.3. Chemo Mechanical Coupling and Reactive Transport

Considering the coupling of THMC processes is crucial for understanding the integrity and long-term behavior of reservoirs throughout CO₂-based EOR and geologic storage. Several geomechanical responses such as pore-pressure increase, thermoelastic stresses, and geochemical rock–fluid interactions lead to significant changes under CO₂ injection conditions. Dissolution of carbonate minerals like the dissolution of calcite and dolomite can change pore geometry and rock stiffness, and influence that evolution of permeability. The dissolution and precipitation of these minerals can alter the pore structure, porosity and permeability of the soil, creating a significant relationship between geochemical reactions and geomechanical behaviour. Experimental studies also have shown that geochemical reactions can be triggered by CO₂ that alter the mechanical properties of carbonate rocks. Evaluation of these effects has been done by the use of uniaxial and triaxial compression tests and ultrasonic P- and S- wave velocity measurements. Typically, the interaction between CO₂ and brine causes a decrease in rock strength, elastic modulus and velocities of ultrasonic waves, but the degree of decrease varies based on the duration of CO₂ – brine interaction and the mineral dissolution and microstructural changes associated with it. Reductions in P- and S-wave velocity were also observed as a function of time in the injection of CO₂-rich water into carbonate samples, believed to be due to dissolution of carbonate and effects on the rock microstructure. The general trend of both P- and S-wave velocity decreasing with increasing injected pore volume is shown for all of the tested samples and experimental conditions, though the amount of velocity decrease is different for each case, as illustrated in Fig 11 [125].

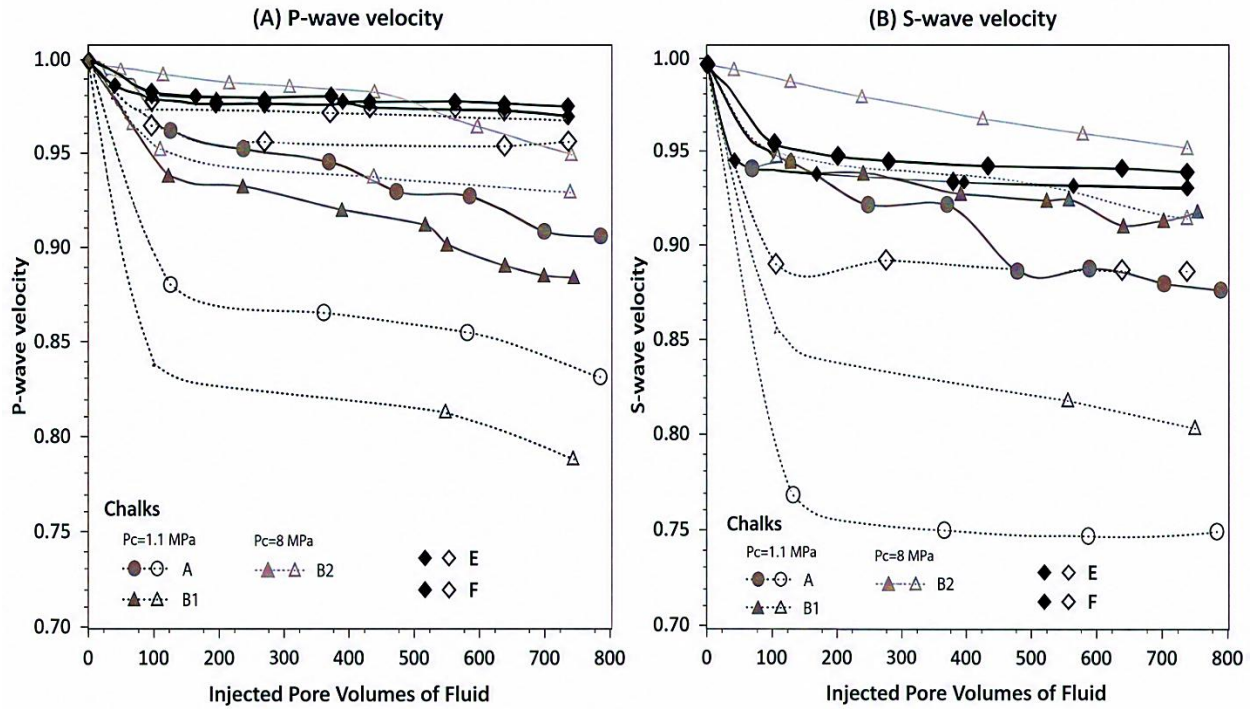


Fig 11 Evolution of normalized P- and S-wave velocities with injected pore volumes of fluid in carbonate rocks under different experimental conditions. Adapted from John Wiley and Sons [125].

These coupled chemo-mechanical effects could cause fracture closure, permeability changes, activation of faults and risks to caprock in stress-sensitive formations. Further, microfracturing can cause tensile stress perturbations due to cold CO_2 injection, which can be near wellbores and near the discontinuities. Minerals dissolution and precipitation processes, which are shown to have significant effects on the evolution of permeability, redistribution of stress and fault stability in long-term field scale CO_2 storage, were recently simulated. The results indicate the need for incorporating geochemical alteration and reservoir geomechanic modelling in the predictive EOR simulation as well as in the carbon-storage simulation. Typical parameterizations of coupled THMC processes involve a dissolution–precipitation kinetic, stress-dependent porosity, permeability and strength degradation laws for minerals and mineral volume fractions. For thermal and pressure driven deformation analyses, THM coupling is usually enough, but popular with THMC approaches are needed for analyses that include reactive transport, alteration of minerals, and long term geochemical weakening of the reservoir that significantly impact reservoir integrity and hydromechanical behavior [13, 126].

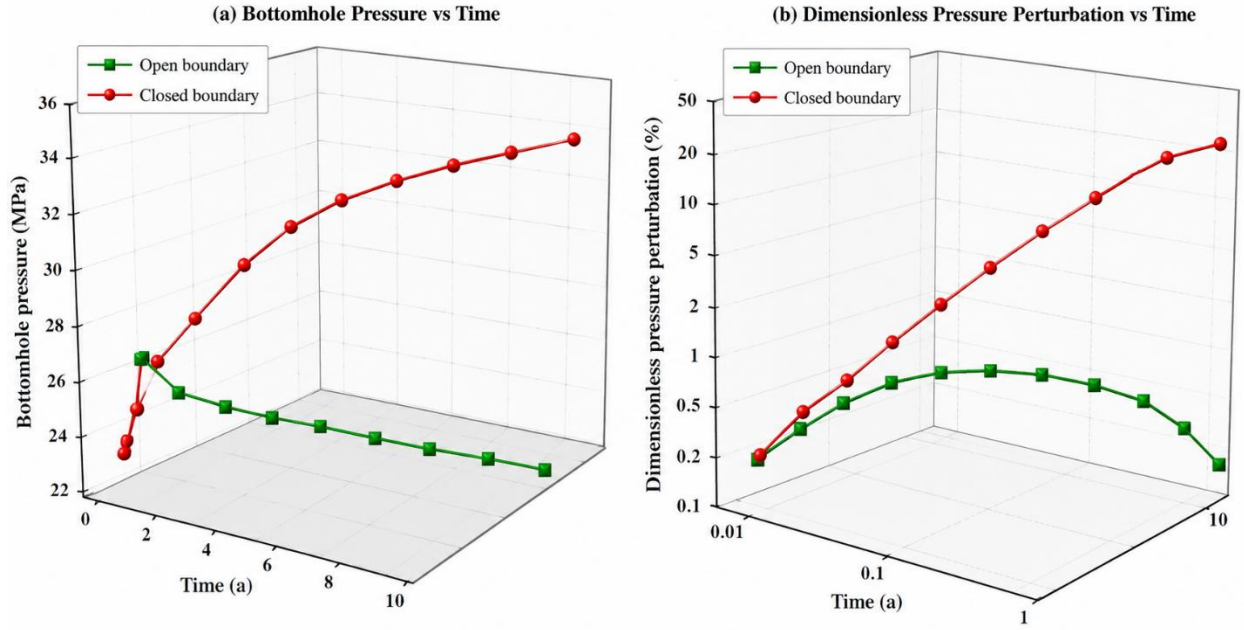


Fig 12 Schematic representation of pressure-induced fault reactivation and associated CO₂ migration under different boundary conditions. Adapted from Wang et al [127].

5.4. Incorporation with Mechanical Earth Models

MEMs are scaled up three-dimensional models of the mechanical properties of the reservoir, constructed as the combination of well logs, seismic interpretations, and on-site measurements of stress[128]. It has been demonstrated that high-resolution MEMs, especially those being calibrated by borehole imaging and microfracture diagnostics, can strongly help to predict fracture propagation and determine caprock integrity in CO₂ storage and injection programs [129]. The integration of digital twin structures and predictive MEM simulations of reservoir geomechanics has become a paradigm shift based on the current developments in the field of reservoir geomechanics. These digital twins in combination with real-time Internet-of-Things (IoT)-based monitoring allow constant model refinement, automatic calibration, and adaptive decision-making, and thus, enhance more efficient control of reservoirs and reduce geomechanical risks[130-132].

5.5. Computational Problems and Future Prospect

Although there has been incredible advancements related to the coupled geomechanical modeling, there are still a few computational and conceptual issues [133]. The computational resource

requirements of fully coupled thermo-hydro-mechanical-chemical (THMC) simulations are computational intense in nature, especially when trying to capture the multiscale heterogeneity of the subsurface formations [106, 134-136]. Currently, no effective modeling structure exists that would allow to connect the simulations at the reservoir-scale to those at the basin-scale while preserving the physical consistency and computational viability [137-139]. In order to address these drawbacks, surrogate modelling and machine-learning tools are being considered as practical methods of quick prediction, data integration, and decision support during EOR-related geomechanical analyses [134, 140]. Surrogate modelling and machine-learning tools can be used to update model parameters and stress-pressure coupling during the near-real-time monitoring of the reservoir, and hence improve predictive accuracy under changing and complex conditions [138, 141]. Besides, uncertainty quantification (UQ) and real-time control strategies are the future trends of adaptive and self-corrective geomechanical simulation systems. With the incorporation of probabilistic modelling, data-driven optimisation and automated calibration; it is hoped that future geomechanical models will be able to provide more accurate forecasts of deformation, fault reactivation, and reservoir performance [142, 143].

6. Discussion and Conclusions

The review indicates that geomechanics cannot be regarded only as a supporting aspect but one of the most important determinants of the performance of EOR and the sustainability of the reservoir in the long term. Through first-principles reasoning on effective stress and poroelasticity to the sophisticated THM and chemo-mechanical theories, it is always observed that such important mechanisms are met: compaction, fault reactivation, caprock deformation, and fracture conductivity hysteresis. Pore pressure changes induced by injections in conjunction with redistribution of stress determine evolution of permeability and could cause instability of already existing fractures or faults on several spatial and temporal levels. This is further enhanced by thermal and chemical injections, which result in rapid thermoelastic deformation, cyclic hardening, mineral dissolution, and change in wettability, which emphasizes the importance of coupled modelling frameworks. One of the rare contributions of the work is the comparative diagnostic framework using normalized risk opportunity indices, which made it possible to evaluate all the thermal, chemical, and gas-based strategies of EOR systematically. This strategy explains trade-offs: despite the fact that thermal EOR has the largest recovery improvement, it is also

characterized by the largest geomechanical risks; on the contrary, the Smart Water injection strategy is a one-step safer choice and is focused on the reduction of the risk, which is not aiming to achieve the maximum recovery. It is this type of synthesis that is able to bridge the gap between mechanistic knowledge and operational decision-making and offer a tool that can be used by researchers and practitioners alike. Based on the case studies reviewed, it appears that the twin benefit of improved recovery and safe carbon storage is impossible without a combination of deterministic geomechanical models and probabilistic risk-assessment systems as well as continuous monitoring of the field. It can be seen that experience with both In Salah and Otway demonstrates that long-term injectivity and containment are significantly dependent on the stability of the caprock in regards to alterations in pore-pressure and temperature. This type of combined approach must also be used in subsequent EOR plans to minimize the geomechanical risks and maximize operational resiliency. Nevertheless, a number of gaps exist in the present body of knowledge: field-scale models have a tendency to underestimate stress anisotropy and dynamic interactions between fluid pressure, temperature and fracture conductivity; upscaling between local case studies to basin-scale prediction models is still hampered by the subsurface heterogeneity and computational complexity; and geomechanics remains largely used as a diagnostic tool and not as a design driver.

In an operational standpoint, geomechanical risk mitigation should be accomplished through ramping up and down injection rates, implementing pressure management below the critical fault-reactivation thresholds, optimizing injection cycles, and monitoring for deformation and seismicity indicators continuously during the EOR project. Using real-time observations for monitoring coupled geomechanical simulations, the strategy of the injection should be dynamically adjusted to minimize the failure of the caprock, fault slip, and losses of injectivity, with a focus on maximizing recovery performance and long-term storage security.

CRedit authorship contribution statement

Asena Golmoradi: Writing – original draft, Methodology, Investigation.

Seyyed Shahab Tabatabaee Moradi: Writing – review & editing, Supervision, Project administration, Methodology, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Data availability

Data will be made available on request.

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