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Geomechanical analysis of formation deformation and permeability enhancement due to low-temperature CO_2 injection in subsurface oil reservoirs

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Abstract

Several benefits of CO_2 injection are reported in the literature such as its ability to mitigate greenhouse gas emissions and the increase in oil recovery at a low cost. However, the correlated reservoir-engineering problems with low-temperature CO_2 injection including formation damage and leakage risk are still uncertain and has not been comprehensively investigated. This research examines the effect of low-temperature CO_2 on lowering of formation breakdown pressure, and the associated formation damage from a geomechanical prospective. This study presents the coupling of the equilibrium stress equation, the system energy balance equation, continuity equation, and saturation equation to develop thermoporoelastic model for the reservoir rock. We determined the cooling-induced formation damage due to decrease in temperature and thermal stresses, formation contraction and tensile stresses, and examine its effects on formation properties, stresses, joint and fracture stability. We observed that low-temperature CO_2 would create a low thermal stress region and thus the formation could fail in tension. This process might increase formation permeability but it would decrease the stability of reservoir, basement and caprock. We analyzed several factors affecting formation deformation such as injection rate for both miscible and immiscible CO_2 flooding, formation porosity, depth, temperature, and formation breakdown pressure. We also compared our results and findings with experimental data, finding excellent match and similar consequences. Furthermore, as a sequence of low-temperature CO_2 injection, the initial formation breakdown pressure was initially at 2560 psi and it reduced to 1928 for immiscible case and 1270 psi for miscible case in the selected case study. We also propose that shallow reservoirs should be avoided for CO_2 capture and storage because of stability issues.

Keywords CO_2 injection · Formation temperature · Temperature reduction · Formation contraction · Thermal cracks

Introduction

Carbon dioxide (CO_2) sequestration is gaining a lot of interest from academia and industry because of its potential to store CO_2 and mitigate its release into the atmosphere. The CO_2 can be sequestrated in a number of subsurface geological structures including un-useable saline aquifers, depleted oil and gas fields, and un-mineable coal seams (Bui et al. 2018). The CO_2 could stay in these geological structures in supercritical conditions in a denser phase but its density would be lower than the formation water (Hitchon et al. 1999). Consequently, the CO_2 leakage risk could be low (Alcalde et al. 2018) and after being present for up to long period of time (millions of years) till it get dissolved into the formation water or mineralized (Benson and Cole 2008). The depleted oil and gas reservoirs are the most important, because these reservoirs are studied in detail, monitored for long during oil and gas production, and thus CO_2 can be efficiently stored in these reservoirs. Moreover, incremental oil is an economic benefit that can be generated by storing it in these reservoirs (Khurshid et al. 2018). For safe and sustainable storage of CO_2, it is important that the temperature and pressure conditions of these reservoirs should be critically analyzed. It will help to ensure that CO_2 is stored safely without any risk of leakage, as its leakage may cause an environmental catastrophe (Parisio et al. 2019).

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Neuzil (1994) mentioned that during permeability measurements on laboratory specimens, the natural permeability at the geological scale is underestimated. Thus, during drilling activities at IDDP-2, all the drilling mud was lost (Friöleifsson et al. 2017). It is believed that the formation in situ permeability was in the range of 10^{-16}–10^{-14} m^2 and is quite possible due to fractured crust composed basaltic (Hurwitz et al. 2007). Moreover, during drilling, the mud hydrostatic pressure reopens the pre-existing fractures and at the same time cooling contracts the surrounding rock. This phenomena could generate an additional fracture aperture (Parisio and Vilarrasa 2020).

For the sequestration of CO_2 in depleted reservoirs, a model was developed by Khurshid et al. (2015). They considered the compaction of a reservoir and determined optimum time for CO_2 injection to store maximum CO_2 in a sustainable way. Moreover, it is essential that the temperature of formation and temperature of injected CO_2 should be compatible. Even during injecting supercritical CO_2, whose injection temperature is 31.1 °C at the surface, as soon as it reaches the reservoir, its temperature is much lower than the corresponding reservoir temperature (Vilarrasa et al. 2019). For example, In-Salah, Algeria the surface temperature and pressure of CO_2 are 35 °C and 2600 psi. When it reaches the reservoir, its temperature and pressure increase to 50 °C and 4350 psi, respectively. However, reservoir temperature is 65˚C, thus their lies a temperature difference of 15 °C between CO_2 and the formation (Bissell et al. 2011).

Moreover, depleted oil and gas reservoirs have a characteristic low-pressure environment and geochemical reactions could worsen the conditions (Khurshid et al. 2020a). These low-pressure environments will cause significant CO_2 expansion and temperature drop in the reservoir (Simon et al. 2010). Similarly, if in case CO_2 is injected in a reservoir before depletion, eliminating the probability of CO_2 expansion and temperature drop. The difference between CO_2 temperature and formation temperature still lies in the range of 5–45 °C (Kim and Hosseini 2014; Khurshid and Choe 2016; Vilarrasa et al. 2015) depending upon surface temperature, depth and geothermal gradient. However, it is mentioned by Jaeger et al., (2007) that a 10 °C change in temperature can induce thermal stresses of about 4350 psi (30 MPa). Therefore, it is very important to consider the change and control the formation temperature drop.

Fjaer et al., (2008) mentioned that fluid temperature decrease affects in two ways. It might change the fluid and formation properties. The cooling of reservoir fluids could cause hydrate formation and lowers CO_2 injectivity. Furthermore, as the formation is confined deep below the earth surface, low-temperature CO_2 will decrease the formation temperature leading to its contraction (Vilarrasa et al. 2014). Where, this contraction and shrinkage may change formation microstructure, inducing tension and creates fractures/ thermal cracks and microseismicity (Segall and Fitzgerald 1998; Enayatpour and Patzek 2013; Khurshid and Choe 2015; Yoshioka et al. 2019; Khurshid et al. 2020b).

It is observed by Bao et al. (2013) that formation shrinkage mainly occurs around the injection well, where it could delay reactivation of old fractures. However, it could create minor fractures in the basement and caprock surrounding the injection zone. For oil and gas recovery point of view this deformation, seismic activities, and fractures would enhance permeability. However, the integrity of the caprock should not be compromised, as its failure could lead to the creation of seepage paths/cracks that might cause leakage of CO_2 to the surface. The probability of their creation and extension is high in the region close to the wellbore (Stork et al. 2015). Peters et al. (2013) found that cooling would not only reduces compressive, tensile and radial stresses but also the vertical stresses. Thus, formation cooling could reduce thermal stresses in all directions. Therefore, the Mohr circle shifts toward the failure envelope, which increases the risk of shear failure. This change in stress state, promotes hydraulic fracturing, enhancing formation permeability but it might lower rock stability.

Rinaldi et al. (2014a) state that the permeability enhancement and microseismicity are caused not only by formation cooling but the CO_2 injection pressure also plays a vital role in amassing cracks and fractures. It is mentioned by Preisig and Prévost (2011) that lower most part of the caprock, which is attached with the reservoir will fracture within 3 years of low-temperature CO_2 injection. However, Vilarrasa et al. (2014) mentions that CO_2 injection will improve the stability of caprock, conditioned that the major principal stress is vertical. On the other hand, Gor et al. (2013) performed detail study of an injection site and its stress levels. They observed that a thermal difference between CO_2 and formation will fracture the caprock in 10 years Rinaldi et al. (2014b).

Therefore, due to differences and contradictory in results, inspires us to develop a coupled thermoporoelastic model to investigate the effect of: low-temperature CO_2 injection, stress perturbation, wellbore integrity, cap rock integrity and fault reactivation. Therefore, in this study, our goal is to investigate the magnitude of formation temperature, CO_2 temperature at wellbore entry, formation temperature reduction, thermal stresses and change in formation breakdown pressure during CO_2 injection. For effective CO_2 enhanced oil recovery (EOR), the CO_2 has to be injected in the formation for years or even for decades. Therefore, the developed model will help to determine heat transfer in the formation, decrease in formation breakdown pressure and estimate the safe injection pressure range. As a result, it can help to avoid fracture/crack initiation and determine various factors that might enhance it. Eventually, it will help to have sustainable

CO_2 injection operations with minimum damage to the formation and caprock.

Thermal stress reduction model

The injectivity of CO_2 is determined by reservoir permeability that is essentially dependent on the reservoir stresses and temperature. Watanabe et al. (2017) performed experiments on fracture granite and found the existence of elastoplasticity (transition permeability), which is controlled by effective mean stresses (a function of temperature). The developed thermal stress reduction model and its framework are shown in Fig. 1. It determines the level of formation cooling and estimates the temperature variation caused due to CO_2 injection. In this study, radial coordinate systems are considered because this coordinate system is suitable for radial flow problems and their solution is computationally more efficient than other systems.

Additionally, the in situ stresses in a reservoir dictate the magnitude of pressure needed to create a fracture with certain size and orientation. These stresses are categorized into three principal compressive stresses: vertical, maximum and minimum horizontal stresses. The maximum principal stress is caused due to the weight of the rock overlying a certain point. The two other principle stresses are maximum and minimum horizontal stresses, which are controlled by regional and local tectonics stresses. Their vertical gradient could vary from basin to basin depending on the formation lithology. These stresses increase with the depth and are perpendicular to each other as shown in Fig. 2. We can determine the magnitude of these principal stresses from the tectonic stress regime in a certain area, depth, pore pressure and rock properties. Moreover, if the maximum principal stress is the vertical stress then the fractures will be vertical. However, in shallow reservoirs where horizontal stresses exceed vertical stresses, fractures will be horizontal.

Fig. 1 Flowchart of the developed thermoporoelastic model for thermal stress reduction analysis
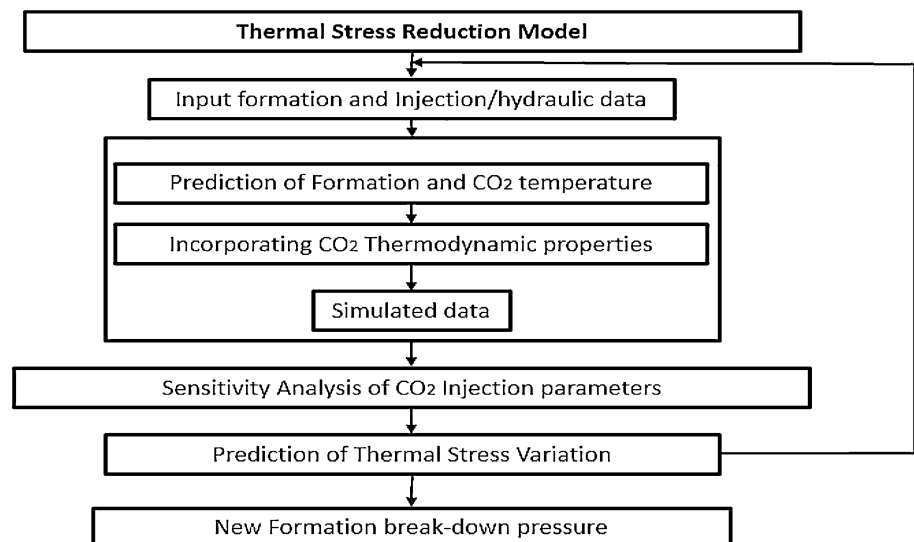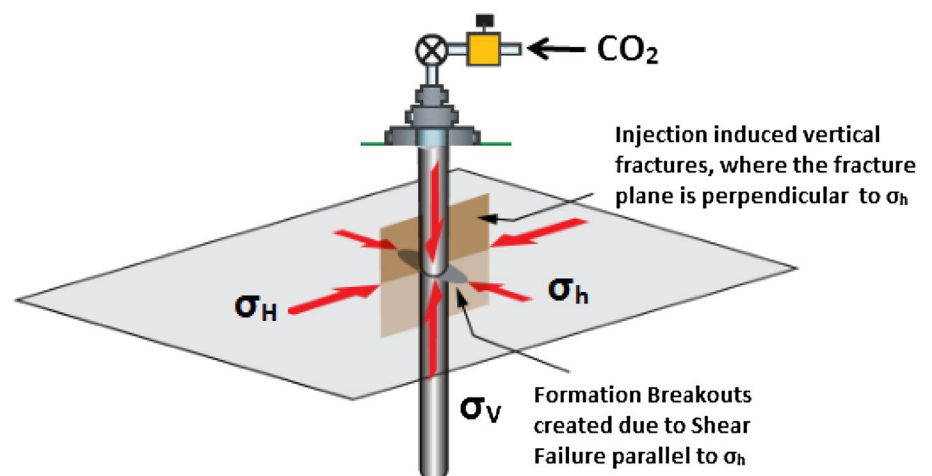

Fig. 2 State of stress in the subsurface porous media

Therefore, we developed a model to determine the temperature drop and related stress tensor change in a formation during CO_2 injection. We used and combined the equilibrium equation, the system energy balance equation, continuity equation, and saturation equation to develop the thermoporoelastic model for the reservoir rock. The reservoir rock is considered as a porous elastic geomaterial. Thus, its equilibrium stress equation is given by Coussy (2004).

$$\nabla \sigma + \rho g = 0 \tag{1}$$

where σ is total stress, ρ is total mass density for the porous media, and g is the acceleration due to gravity. The energy equation relates the temperature of the porous media to its pressure, and it is shown below that the change in volume of the fluid saturated medium due to change in temperature and pressure is

$$[\alpha \rho_s (1-\phi) + \beta \rho_f \phi]\frac{dT}{dt} + \beta \rho_f q \nabla T - \nabla K \nabla^2 T + 3\gamma_s K T_0 \nabla u - 3\gamma_x T_0 \frac{dp}{dt} = 0 \tag{2}$$

where α is the specific heat for formation, ρ is the density, φ is the porosity, β is the specific heat for reservoir fluids, T is the temperature, u is the solid displacement, t is time, γ is coefficient of thermal expansion, K is the thermal conductivity, with subscript s, f and e showing solid, fluid and rock matrix. The continuity equation is derived by using mass conservation equation and Darcy law: which describes the fluid flow in porous media.

$$q = \nabla(\rho_f v) + \frac{\partial}{\partial t}(\phi \rho_f) \tag{3}$$

where v is the Darcy's velocity in the porous media. Therefore, the storage model for the porous media is given by

$$v = -\frac{k(\rho_f hg + \Delta p_f)}{\mu} \tag{4}$$

$$\frac{\partial}{\partial t}(\phi \rho_f) = \chi \rho_f \frac{\partial p_f}{\partial t} \tag{5}$$

where k is the permeability, ρ is the density, p is pressure, h is hydraulic head, μ is fluid viscosity, φ is the porosity, χ is storage coefficient, λ is Biot's coefficient, and ε is the strain in the formation. Combining Eqs. 3–5 we will get the continuity equation, which is given by

$$\nabla \rho_f \left[-\frac{k(\rho_f hg + \Delta p_f)}{\mu} \right] + \chi \rho_f \frac{\partial p_f}{\partial t} = -\rho_f \lambda \frac{\partial \varepsilon}{\partial t} \tag{6}$$

The fluid saturation equation for the porous media is similar to the continuity equation and is written for only a single phase. Therefore, fluid saturation equation is given by

$$q_i = \phi \frac{d}{dt}(\rho_i S_i) + \rho_i S_i \left(\frac{d\phi}{dt} \right) + \Delta(\rho_i Q) \tag{7}$$

where S is phase saturation for phase i, Q is the fluid mass flux.

The above equations are coupled with fluid pressure, saturation and formation temperature, and then the solution is obtained by using finite difference method to determine the change in temperature and thermal stresses in a radial geometry, where more details can be found in Prévost (1981). Once the formation temperature is obtained, the bottom-hole breakdown pressure (P_b) can be calculated by the following model (Ollivia and William 2013).

$$P_b = 3\sigma_h - \sigma_H - \lambda P_p + \Delta \sigma_T \tag{8}$$

where σ, λ, P are stress, Biot coefficient, pressure and subscript h, H, p and T represent minimum in situ stress component, maximum in situ stress component, pore pressure and temperature of the reservoir, respectively. It is mentioned by Fjaer et al., (2008) that the thermal stress component is dependent on rock stiffness, which means that it is more significant in hard rocks than soft rocks. Likewise, it is also proportional to the thermal expansion coefficient as evident in the above equation.

Results, validation and discussion

To analyze the effect of CO_2 injection, a vertical depth of 2800 m is assumed, and formation properties used for analysis are shown in Table 1. The different properties of CO_2 and formation are taken from the literature, which are both experimental and field data. It is observed that permeability enhancement is a complex process and thermal stress reduction is not the only exclusive physical mechanism. That is responsible for permeability enhancement, which creates, widen, or even reopen the existing fractures. Therefore, we determined the change in formation temperature during CO_2 injection, thermal stresses and their effect on total change in formation stresses in, near and far from wellbore region with developed thermoporoelastic model. After analyzing formation temperature profiles, it is found that formation temperature profile behaves nonlinearly near the injection point as shown in Fig. 3. Subsequently, detail study showed that this nonlinear behavior occurs due to fluid expansion, turbulence and Joule–Thomson effect, which causes an additional temperature drop and decreases formation thermal

Table 1 Formation and CO_2 properties used in geomechanical analysis

Properties	Value	Unit
Initial temperature	85	°C
Vertical stress	3.33	psi/m
Minimum horizontal stress	1.8	psi/m
Poisson's ratio	0.36	
Maximum horizontal stress	3.00	psi/m
Pore pressure gradient	1.4	psi/m
Formation coefficient of linear thermal expansion	1.2×10^{-5}	1/°C
CO_2 coefficient of linear thermal expansion	2.8×10^{-3}	1/°C
Young's modulus	2.17×10^6	psi
Geothermal gradient	0.03	°C/m
Formation depth	2800	m
Simulation time	360	day
Formation radius	4	m
CO_2 Injection pressure	1078	psi
CO_2 density	800	kg/m³
CO_2 specific heat	2.8	kJ/kg K

stresses (Oldenburg 2007). This finding demonstrates an overall trend of formation temperature profile during CO_2 injection.

Figure 3 demonstrates the change of initial formation temperature due CO_2 injection. This change is calculated at constant CO_2 reservoir entry temperature 45 °C, reservoir porosity 25%, and initial formation temperature 85 °C. We considered CO_2 reservoir entry temperature 45 °C, because the injection temperature of supercritical CO_2 at the surface is 31.1 °C. However, when CO_2 reaches the reservoir its temperature increases to 45 °C because of geothermal

gradient. This study used the thermal simulator developed by Ilyas and Choe (2016) to calculate the temperature of CO_2. Therefore, it is evident that the difference between initial temperature of formation and CO_2 temperature is 40 °C.

The injection of this low-temperature CO_2 will definitely decrease formation temperature. Thus, we used the thermoporoelastic model to determine the formation temperature drop. Which shows that around wellbore the temperature decreases from 85 °C to 53 °C after 1 year of CO_2 injection as shown in Fig. 3. This decrease of formation temperature would reduce thermal stresses and disturbs the whole formation stress tensor, i.e., vertical, horizontal, tangential, radial and shear stresses. Moreover, it is evident from Fig. 3 that the initial formation breakdown pressure was initially at 3336 psi and reduced to 2175 psi. This 1161 psi decrease is mainly due to formation cooling and it proves that the formation has deformed and its breakdown pressure has decreased by 34%. For such decrease, the Mohr circle shift toward the left and it may to fail in tension (Vilarrasa 2016). This phenomenon would lead to simultaneous formation deformation, decrease of formation collapse and fracture pressure (Fjaer et al. 2008). Additionally, this decrease in formation fracture pressure shrinks compressive stresses and initiates tensile stresses because deep formations are unable to contract freely. Thus, it will create new tensile fractures and it would also reopen the existing fractures, as observed by Goodarzi et al. (2015).

We used the scanning electron microscopic observations performed by Siratovich et al., (2015) to illustrate the behavior and effect of thermal stress reduction on rock and its properties. The observations in Fig. 4 show an investigation of pretest rock sample (Fig. 4a) and posttest rock sample (Fig. 4b). It is evident from the scans that the microstructure of the rock sample has changed due to the injection of
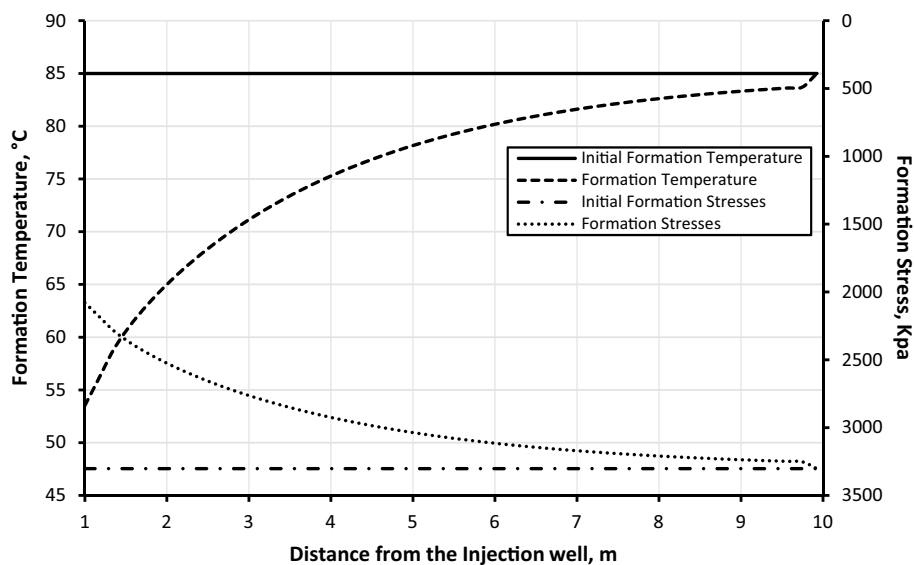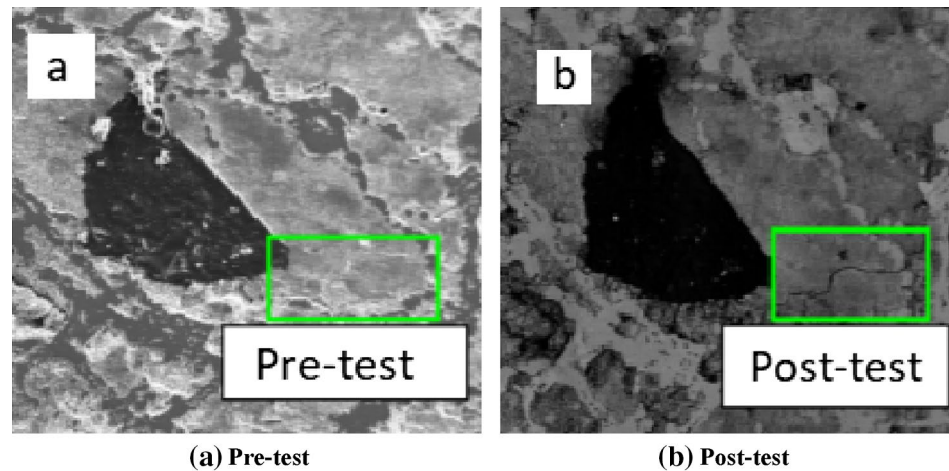
Fig. 3 Evolution of Formation temperature and stresses profile in a reservoir during CO_2 injection

Fig. 4 Scanning Electron Microscope observations of thermal stimulation of a rock sample (Siratovich et al. 2015 **a** Pretest. **b** Posttest

(a) Pre-test   **(b) Post-test**

low-temperature fluid. It can be observed from Fig. 4 that the injection of low-temperature fluid has enhanced the permeability by increasing fractures in the formation. Thus, these findings validate the results of our developed thermoporoelastic model.

Figure 5 illustrates the effect of formation porosity on heat transfer during CO_2 injection. When CO_2 is injected in the porous media, its flow transfers heat from the porous media which is characterized by formation geometry, surface area of contact between solid matrix and CO_2. Thus, it is evident from Fig. 5 that when the porosity is low (10 percent). The rate of heat transfer increases because the surface area of contact between the fluid and rock is high. However, when the porosity of the formation is increased to 20 percent and then to 40 percent. The surface area of contact between the fluid and rock decreases and this decrease in surface area of contact causes a less drop in formation temperature for 20 and 40 percent porous rock as shown in Fig. 5. Moreover, the significant drop in temperature at 10 percent porous rock

leads to substantial decrease in formation breakdown pressure in-comparison to 20 and 40 percent porous rock as presented in Fig. 5. Thus, the extent of fluid–solid surface area of contact controls the formation temperature and formation breakdown pressure. Thus, when the formation porosity is low, the surface area of fluid-rock contact is high and it increases the rate of heat transfer, leading to additional temperature drop and significant decrease in formation breakdown pressure. Furthermore, porosity has ephemeral effect on rock properties and the decrease in thermal stresses cannot be replenished until the injection of CO_2 is stopped. The findings of Oldenburg (2007) support our results of decrease in formation stresses and thermal contraction. Therefore, formation properties mainly porosity has significant effects on heat transfer throughout the formation and substantially disturbs the mechanical properties of the reservoir.

The CO_2 injection pressure effects the heat transfer and it would induce tension in the formation as shown in Fig. 6. Where CO_2 is injected at immiscible or miscible pressures

Fig. 5 Thermal disturbance due to variation in formation porosity during CO_2 injection
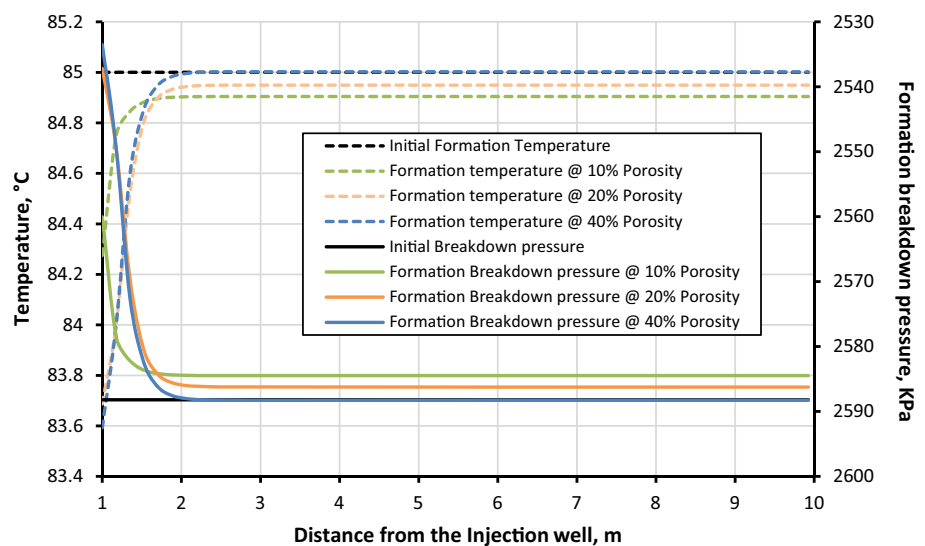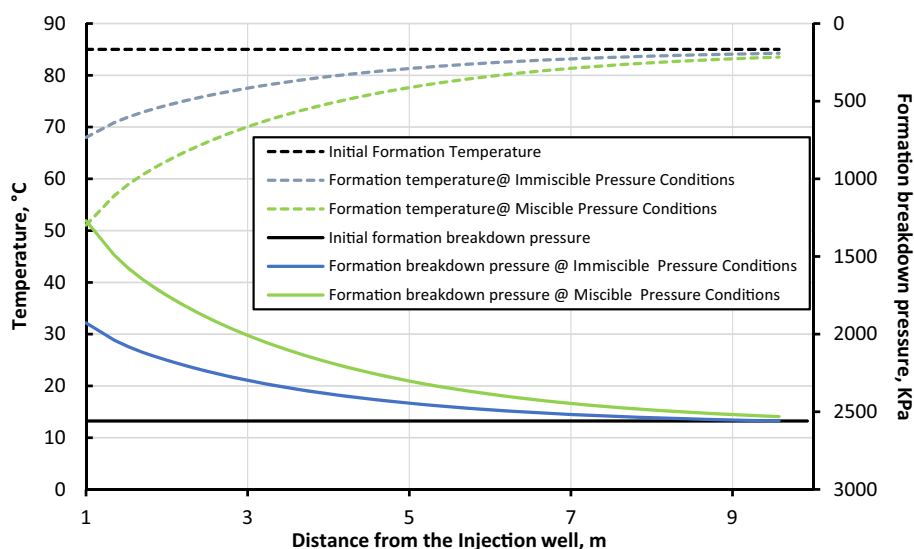
Fig. 6 Evolution of formation temperature and heat transfer at various injection pressures

in a reservoir with constant porosity. We considered 540 and 1078 psi for immiscible and miscible case, respectively. Because 1078 psi is the supercritical pressure for CO_2. It can be observed from Fig. 6, that high-pressured CO_2 created a low-temperature region around the injection well. The reason for this behavior is that the formation temperature is transient in nature and its temperature drop rapidly at high rate of CO_2 injection as evident in the miscible case. Additionally, the creation of this low-temperature region is not surprising because high injection pressure could cause a high flow rate, thus more fluid would flow through the porous media. Where it significantly decreases the formation temperature. Moreover, it is obvious from Fig. 6 that the initial formation breakdown pressure was initially at 2560 psi and it reduced to 1928 for immiscible case and 1270 psi for miscible case. This difference of 658 psi formation breakdown pressure between miscible and immiscible injection proves that the formation has deformed and its breakdown pressure has decreased rapidly in miscible injection.

Consequently, this temperature decrease lowers the formation thermal stresses leading to thermal contraction, tensile stresses initiation, creation of new fractures and shear-slip of existing fractures during miscible CO_2 flooding. Moreover, for low injection pressure which is characterized by low flow rate. This low flow rate will cause less heat transfer and nominal decrease in thermal stresses. Therefore, it is suggested that the injection pressure of CO_2 should be design such that it transfers less heat and its rate of injection decreases with time. This practice will avoid the disturbance of formation stress tensors, formation deformation, creation of new fractures and opening of existing fractures.

Figure 7 shows the comparison of heat transfer by CO_2 at different reservoir depths at the same operating and formation properties as shown in Table 1. The temperature of the formation at depths of 2800 m and 3500 m was calculated

at a constant geothermal gradient porosity and CO_2 injection pressure 0.03 °C/m, 25%, 1078 psi, respectively. The determined temperature of the formations was 84 and 105 °C for the selected formation depth as mentioned above. With the developed methodology, the variation in formation temperature and thermal stresses was determined as shown in Fig. 7. It is evident from this Fig. 7 that the formation temperature after CO_2 injection at depth of 3500 m remains almost constant with less decrease in formation temperature and minimal thermal disturbance. However, when the depth decreased to 2800 m, the temperature of formation decreases near the wellbore at a high rate. Therefore, it is apparent that when the reservoir is shallower, the temperature difference between CO_2 and formation will high and it causes an elevated decrease in formation temperature and thermal stresses, these results are supported by the findings of Khurshid and Choe (2018). Therefore, accurate knowledge of CO_2 temperature at a given depth helps to take the right decision to control its temperature by decreasing the injection rate, thermal and tensile stresses.

Summary and conclusions

The effect of low-temperature CO_2 injection on lowering of formation breakdown pressure and formation damage has been successfully predicted from a geomechanical aspect using the coupled thermoporoelastic model. The main findings of this study can be summarized as follows:

- The developed model can be used as an effective tool to model thermomechanical deformation of porous media during CO_2 injection and investigate the effect of temperature and thermal stress reduction.

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Fig. 7 Thermal evolution in a reservoir at different formation depth and temperature
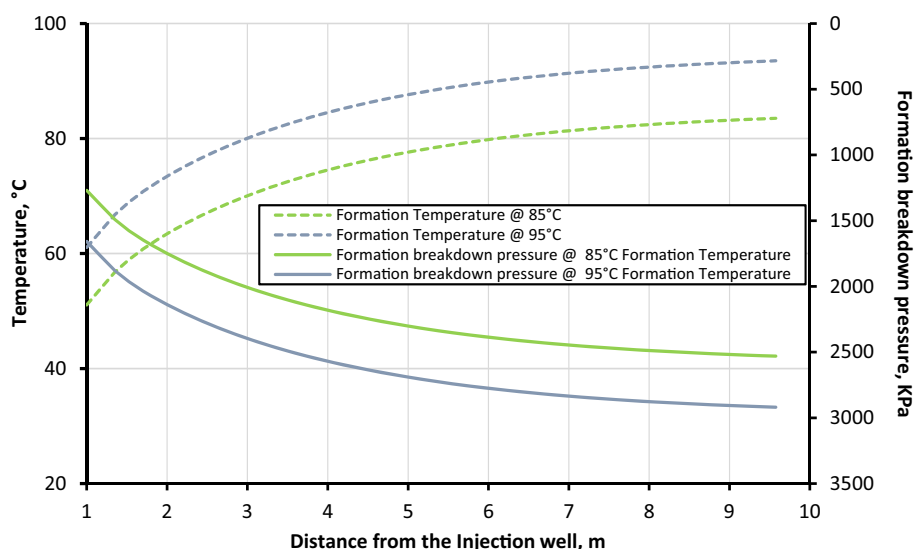
- CO_2 injection reduces the formation temperature and thermal stresses and induces tensile stresses leading to lowering of formation breakdown pressure.
- Change in temperature and its spatial distribution is affected by formation properties such as porosity, thermal expansion, rate of CO_2 injection, depth and stress state.
- Shallow reservoirs should be avoided and deep reservoirs should be preferred due to the likelihood of lowering of formation breakdown pressure and formation damage.
- The injection of low-temperature CO_2 reduced the thermal stresses and initiated fracturing, cracking and microseismicity which could increase the formation permeability. However, it could compromise the safety and sustainable storage of CO_2.
- For selected case study, the formation breakdown pressure was initially at 2560 psi, after the injection of low-temperature CO_2, it reduced to 1928 for immiscible case and 1270 psi for miscible case.
- It is suggested to decrease CO_2 injection pressure periodically over the time, during miscible flooding. With the recommended approach, we successfully mitigated the formation contraction, fracturing, microseismicity, its deformation and surface leakage.
- Formation damage and reduction of formation breakdown pressure by low-temperature CO_2 and the associated oil recovery are very case-dependent and hence, the findings of this research cannot be generalized.

Declarations

Conflict of interest We, the authors, are aware of no conflict of interest associated with this publication, and there has been no significant financial support for this work that could have influenced its outcome.

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