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Geomechanical response of overburden caused by CO₂ injection into a depleted oil reservoir



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ABSTRACT

This study investigates the hydro-mechanical aspects of carbon dioxide (CO₂) injection into a depleted oil reservoir through the use of coupled multiphase fluid flow and geomechanical modeling. Both single-phase and multiphase fluid flow analyses coupled with geomechanics were carried out at the West Pearl Queen depleted oil reservoir site, and modeling results were compared with available measured data. The site geology and the material properties determined on the basis of available geophysical data were used in the analyses. Modeling results from the coupled multiphase fluid flow and geomechanical analyses show that computed fluid pressures match well with available measured data. The hydro-mechanical properties of the reservoir have a significant influence on computed fluid pressures and surface deformations. Hence, an accurate geologic characterization of the sequestration site and determination of engineering properties are important issues for the reliability of model predictions. The computed fluid pressure response is also significantly influenced by the relative permeability curves used in multiphase fluid flow models. While the multiphase fluid flow models provide more accurate fluid pressure response, single-phase fluid flow models can be used to obtain approximate solutions. The ground surface deformations obtained from single-phase fluid flow models coupled with geomechanics are slightly lower than those predicted by multiphase fluid flow models coupled with geomechanics. However, the advantage of a single-phase model is the simplicity. Limited field monitoring of subsurface fluid pressure and ground surface deformations during fluid injection can be used in calibrating coupled fluid flow and geomechanical models. The calibrated models can be used for investigating the performance of large-scale CO₂ storage in depleted oil reservoirs.

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1. Introduction

Several techniques are under development for reducing anthropogenic greenhouse gas emissions due to the concerns over global climate change. Beyond improving energy efficiency and switching to renewable energy resources, carbon sequestration has emerged as a means to continue the use of fossil fuels without significant environmental impact. Geologic sequestration has been identified as one of the methods for disposal of carbon dioxide

(CO₂), rather than venting it into the atmosphere (Bryant, 2007; Michael et al., 2010; Eiken et al., 2011; Hosa et al., 2011; DOE-NETL, 2012; Wolaver et al., 2013; Xu et al., 2016). The main types of formations that have been suggested for the sequestration of CO₂ are depleted oil and gas reservoirs, coal seams, and saline formations. In some cases, injection of CO₂ into oil/gas reservoirs may also lead to enhanced oil or gas production (Ferguson et al., 2009; Gaspar Ravagnani et al., 2009; Godéc et al., 2011; DOE-NETL, 2012; Hill et al., 2013; Khan et al., 2013; Alam et al., 2014; Olea, 2015; Stalgorova and Babadagli, 2015).

Industrial-scale sequestration projects have been undertaken to store CO₂ in geologic formations. These projects include the Sleipner project in the North Sea (Gale et al., 2001; Michael et al., 2010; Hosa et al., 2011; Verdon et al., 2013), the In Salah project

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in the Saharan desert (Michael et al., 2010; Hosa et al., 2011; Ringrose et al., 2013), and the Weyburn project in North Dakota (White et al., 2004; Rostron and Whittaker, 2011; Mayer et al., 2013; Njiekak et al., 2013; Verdon et al., 2013). Several smaller pilot projects for sequestration have also been performed during the past several years, including the Frio project (Ghomian et al., 2008; Hovorka et al., 2005; Kharaka et al., 2006), the Big Fenn Valley project (Gunter, 2002), and the West Pearl Queen project (Pawar et al., 2003, 2006; Wilson et al., 2005).

Research on the geomechanical response at sequestration sites has been established as a factor of importance for geologic sequestration (Mathias et al., 2009; Ferronato et al., 2010; Cappa and Rutqvist, 2011; Chiaramonte et al., 2011; Morris et al., 2011; Khakim et al., 2012; Rutqvist, 2012; Castelletto et al., 2013; Kim and Hosseini, 2014; Rutqvist et al., 2014; Teatini et al., 2014; Vilarrasa et al., 2014; Wang et al., 2016). It is known that as fluids are injected into (or produced from) a reservoir, the pressures within the fluid media change, causing the stress field for the surrounding rock material to change and the rock to deform (Geertsma, 1973; Vasco et al., 2001; Vasco and Ferretti, 2005; Selvadurai, 2009; Deflandre et al., 2013; Zhou and Burbey, 2014; Selvadurai and Kim, 2016). Potential damages to wellbores and other related infrastructure facilities may occur due to ground movements caused by large-scale CO₂ injections. Prior knowledge of the extent of these ground movements could help prevent such damages. Additionally, the change in the geomechanical stress field can also cause faults or fractures in the caprock to open, thereby providing pathways for CO₂ to leak out of the target formation (Morris et al., 2011; Rutqvist, 2012; Siriwardane et al., 2013; Tao et al., 2013). Therefore, predictive modeling techniques for coupled fluid flow and geomechanics are needed for determining the magnitudes of fluid pressure changes and ground displacements caused by fluid injection.

For sequestration goals to be successful, technologies must be developed to help predict where CO₂ migrates within the subsurface and to ensure that it does not return to the atmosphere. The processes of CO₂ injection and associated ground movements in the general cases represent coupled multiphase flow and deformations. There have been a number of studies on coupled single-phase fluid flow and deformations related to fluid injection or extraction (Geertsma, 1973; Yin et al., 2011; Siriwardane et al., 2013; Kim and Selvadurai, 2015). Several studies involving coupled multiphase fluid flow and geomechanics for CO₂ storage in saline aquifers have been reported in the literature (Mathias et al., 2009; Rutqvist et al., 2009; Morris et al., 2011; Siriwardane et al., 2013; Vilarrasa et al., 2014). Limited studies have been performed on coupled multiphase fluid flow and geomechanics related to water flooding in oil reservoirs (Minkoff et al., 2003; Kim et al., 2013; Shafiei and Dusseault, 2013). However, none of the aforementioned published literature involves coupled multiphase fluid flow and geomechanical modeling of CO₂ injection into a depleted oil reservoir. This paper addresses fluid pressure and ground response due to CO₂ injection into a depleted oil reservoir by considering coupled multiphase fluid flow and geomechanics.

There have been a number of publications (Fang and Khaksar, 2013; Pang et al., 2013; Amadu and Miadonye, 2014; Eshiet and Sheng, 2014; White et al., 2014) where the potential for CO₂ injection into depleted oil reservoirs has been discussed. However, none of the above papers present any geomechanical modeling results associated with CO₂ injection into a depleted oil reservoir. In a recent study, an experimental investigation on chemical-mechanical coupling in a depleted oil reservoir subjected to long-term CO₂ exposure was presented (Hangx et al., 2015). Huang et al. (2013) presented a coupled flow and geomechanical simulator for water injection into a heavy oil reservoir. While the

mathematical formulation has similarities to the geomechanical study presented in this paper, none of those papers involve CO₂ injection into a depleted oil reservoir. Moreover, there have been several studies on the geomechanical modeling of CO₂ injection into saline aquifers (Alpak and Wheeler, 2012; Liu and Rutqvist, 2013), but not in depleted oil reservoirs. Hawkes et al. (2005) provided a review of geomechanical factors affecting the integrity of depleted oil and gas reservoirs during CO₂ injection. The novelty of the research presented herein is the modeling of coupled multiphase fluid flow and geomechanics of CO₂ injection into a depleted oil reservoir.

Computational modeling of coupled flow behavior and geomechanical response at the West Pearl Queen pilot site, which is a depleted oil reservoir, is presented in this paper. Coupled single-phase and multiphase fluid flow analyses with geomechanics were carried out to investigate the pressure response and overburden ground response. Only a few geomechanical modeling studies have been carried out at field sites (such as Sleipner, In Salah, and Weyburn) combined with monitoring techniques to understand the geomechanical response of CO₂ injection into deep geologic media (Rutqvist et al., 2009; Morris et al., 2011; Rutqvist, 2012; Rinaldi and Rutqvist, 2013; Verdon et al., 2013; Gondle and Siriwardane, 2014). Deployment of field monitoring techniques can be expensive; however, computational models combined with limited field instrumentation would be very helpful for monitoring in sequestration projects.

The objectives of this paper are to: (1) perform coupled single-phase fluid flow and geomechanical analyses, (2) perform coupled multiphase fluid flow and geomechanical analyses, and (3) compare the modeling results with available field measurements at a depleted oil reservoir during CO₂ injection. The computational effort involved in a coupled multiphase fluid flow and geomechanical model is significantly higher than that involved in a single-phase model. In this paper, results from single-phase and multiphase fluid flow modeling are compared with each other to determine the suitability of these models for simulating CO₂ storage in depleted oil reservoirs. Modeling results were compared with available measured data in order to calibrate these models. Limited subsurface fluid pressure measurements with field monitoring results of ground surface deformations can be used in calibrating coupled fluid flow and geomechanical models. The calibrated models can be used for investigating the performance of large-scale and long-term CO₂ storage in depleted oil reservoirs.

2. Site description

The West Pearl Queen field is located in New Mexico in the Permian basin (Westrich et al., 2001; Dutton et al., 2004). This pilot site is located approximately 40 km (25 miles) southwest of Hobbs, Lea County in New Mexico, as shown in Fig. 1. In the field experiment performed at this site, CO₂ was injected into the Shattuck member of the Queen formation (a sandstone layer), which is located at a depth of about 1371.6 m (4500 ft). This sandstone layer has a thickness of about 15.24 m (50 ft). There has been significant oil recovery from this reservoir in the area where the pilot sequestration test was conducted. It has been reported that the Shattuck member predominantly consists of sandstone with some siltstone, and sandy siltstone (Westrich et al., 2001). Approximately 2090 t of CO₂ was injected into the Stivason #4 well during a 53-day period (Pawar et al., 2003, 2006; Malaver et al., 2004; Wells et al., 2007).

The West Pearl Queen field is located in the Artesia platform sandstone play of southeastern New Mexico, in Lea County. The field site is developed on a small dome-shaped structure located mostly within section 028 of township 19S/34E. Stratigraphically,

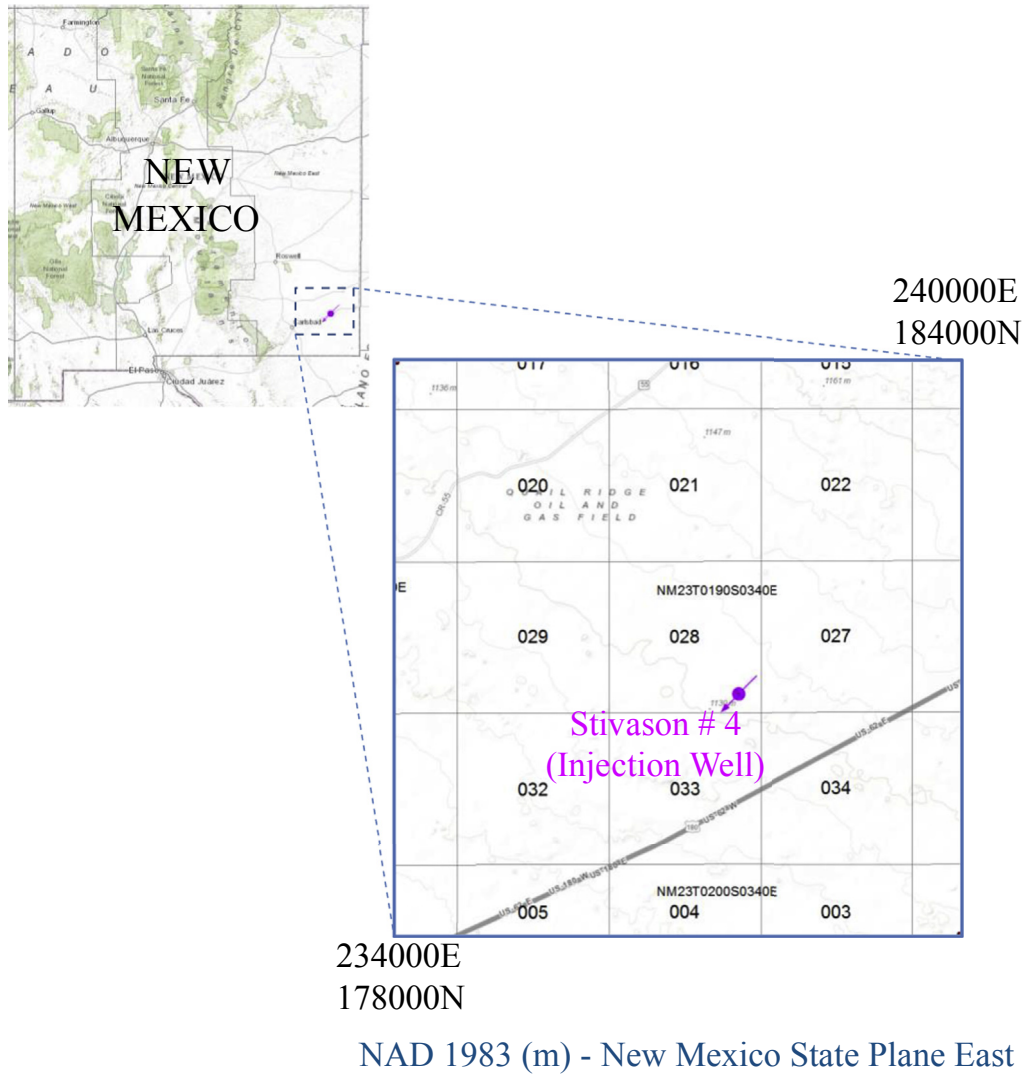


Fig. 1. Location of the Stivason #4 injection well.

the fields in the Artesia play produce from the Queen, Seven Rivers and Yates formations of the middle Permian Artesia Group. Cumulative oil production from the Pearl field has been reported to be over 22 million barrels (Dutton et al., 2004).

The CO₂ injection interval of the West Pearl Queen field is the Shattuck sandstone member of the Queen formation. The Shattuck sandstone member lies at the top of the Queen formation (see Fig. 2), at a depth of approximately 1371.6 m (4500 ft) beneath the surface at the site. The reservoir contains three relatively high porosity zones and is capped by dolomite and shale. Core derived permeability and porosity data from a nearby well (Stivason #1 well) were taken from the published literature (Westrich et al., 2001; Wells et al., 2007).

The strata overlying the Shattuck sandstone member in the vicinity of the pilot site consist of siliciclastic (sandstone, siltstone, and shale) and evaporitic (gypsum, anhydrite, and halite) type rocks (Nicholson and Clebsch, 1961). These strata were subdivided into several mechanical layers having roughly similar physical properties, as inferred from their Young's modulus and bulk density values (Fig. 3 and Table 1). Young's moduli for layers 6–13 were calculated directly from density and sonic log data such as the compressive and shear wave velocities (Sheriff, 1991).

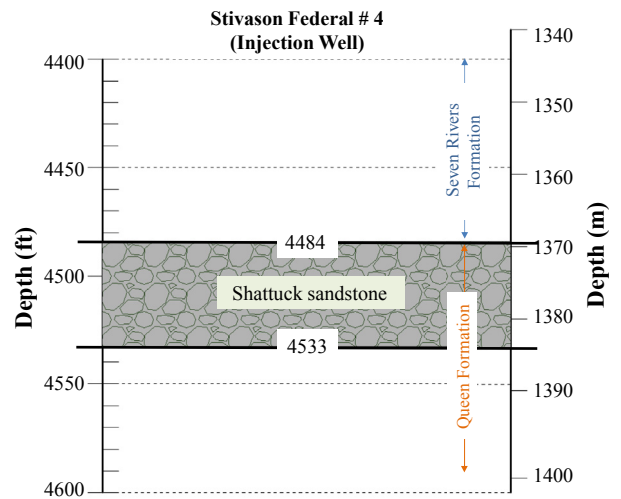


Fig. 2. Depth of Shattuck sandstone member.

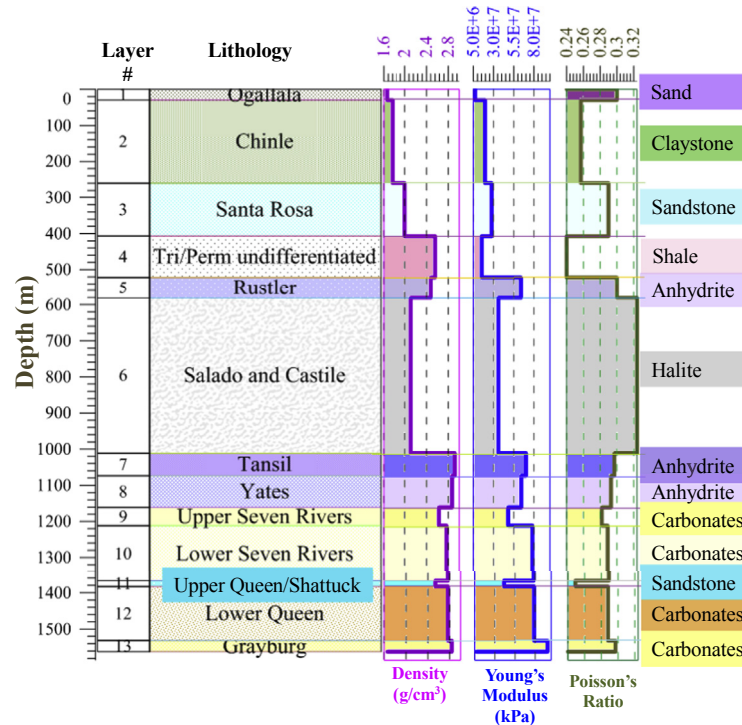


Fig. 3. Mechanical layers derived for the model.

Table 1
Geometric details and geomechanical properties used in the modeling study.

Mechanical layer	Formation	Depth to top (m)	Depth to base (m)	Thickness (m)	Average density (g/cm ³)	Average Poisson's ratio	Young's modulus (GPa)
1	Ogallala	0	30	30	1.66	0.3	10
2	Chinle	30	260	230	1.76	0.257	19.4
3	Santa Rosa	260	407	147	2	0.29	27.6
4	Tri/Perm undifferentiated	407	522	115	2.56	0.24	15.3
5	Rustler	522	581	59	2.48	0.3	63.9
6	Salado and Castile	581	1011	430	2.11	0.324	35.9
7	Tansil	1011	1074	63	2.92	0.297	70.1
8	Yates	1074	1161	87	2.87	0.293	64.4
9	Upper Seven Rivers	1161	1212	50	2.63	0.282	48
10	Lower Seven Rivers	1212	1367	160	2.77	0.289	78.1
11	Upper Queen/Shattuck	1367	1383	15	2.54	0.249	41.3
12	Lower Queen	1383	1532	149	2.77	0.288	78.6
13	Grayburg	1532	1562	30	2.84	0.297	95.4

3. Mathematical details

3.1. Multiphase fluid flow in porous media

For water (w), oil (o), and CO₂ (c) components, multiphase fluid flow equations can be found in published literature (Chen et al., 2006; Martinez et al., 2013). The phase (liquid or gas) of the oil or CO₂ is incorporated in the equation of state built into the CMG code (CMG, 2013) used in the study. The single-phase fluid flow formulation will be a special case of the multiphase fluid flow formulation. The governing equations for flow through porous media are given by the conservation of mass, Darcy's law, and an equation of state. Mathematical details of single-phase fluid flow formulation can be found elsewhere (Minkoff et al., 2003; Chen et al., 2006). The basic equation of continuity for multiphase fluid flow in a porous medium can be written as (Chen et al., 2006; Martinez et al., 2013):

(1) For the water component:

$$\frac{\partial(n\rho_w S_w)}{\partial t} = -\nabla \cdot (\rho_w v_w) + q_w \quad (1)$$

$$v_w = -\frac{k_{rw}}{\mu_w} k(\nabla p_w - \rho_w g \nabla z) \quad (2)$$

(2) For the oil component:

$$\frac{\partial(n\rho_o S_o)}{\partial t} = -\nabla \cdot (\rho_o v_o) + q_o \quad (3)$$

$$v_o = -\frac{k_{ro}}{\mu_o} k(\nabla p_o - \rho_o g \nabla z) \quad (4)$$

(3) For the CO₂ component:

$$\frac{\partial(n\rho_c S_c)}{\partial t} = -\nabla \cdot (\rho_c v_c) + q_c \quad (5)$$

$$v_c = -\frac{k_{rc}}{\mu_c} k(\nabla p_c - \rho_c g \nabla z) \quad (6)$$

where k is the permeability, n is the porosity, t is the time, z is the depth, k_{rw} is the relative permeability of water, k_{ro} is the relative permeability of oil, k_{rc} is the relative permeability of CO₂, p_w is the water pressure, p_o is the oil pressure, p_c is the CO₂ pressure, q_w is the mass flow rate of water, q_o is the mass flow rate of oil, q_c is the mass flow rate of CO₂, S_w is the water saturation, S_o is the oil saturation, S_c is the CO₂ saturation, v_w is the velocity of water, v_o is the velocity of oil, v_c is the velocity of CO₂, μ_w is the viscosity of water, μ_o is the viscosity of oil, μ_c is the viscosity of CO₂, ρ_w is the density of water, ρ_o is the density of oil, ρ_c is the density of CO₂, g is the gravitational constant, and ∇ is the gradient operator.

Since the pore space is filled with water, oil, or CO₂, it should fulfill the following condition:

$$S_w + S_o + S_c = 1 \quad (7)$$

3.2. Mathematical details of geomechanics

The geomechanical response was modeled by considering the coupled poroelasticity formulation based on the theory of linear poroelasticity (Biot, 1941; Huang et al., 2013). The numerical models were based on the finite element method. The multiphase flow behavior leads to nonlinearities in the mathematical formulation (Rutqvist et al., 2002; Lewis et al., 2003; Ghomian et al., 2008; Huang et al., 2013). In the coupled single-phase fluid flow and deformation analyses, the injection of CO₂ into the porous medium was modeled by assuming single-phase fluid flow (e.g. no capillary pressure or relative permeability). The deformation of the rock formation was modeled by assuming the linear elastic properties shown in Table 1. Computations were carried out by considering the injection as an axisymmetric problem. In the coupled multiphase fluid flow and geomechanics, the relative permeability (corresponding to the percentage saturation of each phase) would appear as a multiplier to the absolute permeability, and it would change with time. The relative permeability would depend on the wetting characteristics of the porous media, as well as the fluid phases. In this study, the influence of capillary pressure was not considered. The compressibility of the fluid phase would add another complicated dimension to the analyses. Moreover, if one fluid was significantly less dense than the other (as is often the case with CO₂), then buoyancy effects would play a role in determining the distribution of the fluid phases.

The conservation of fluid mass relates the fluid velocity to the displacements in the medium as described in the literature (Biot, 1941; Vilarrasa et al., 2011; Huang et al., 2013). These governing equations can be solved numerically by using the finite element formulation (Lewis and Schrefler, 1987). In this paper, the flow-deformation problem was formulated as an axisymmetric problem. Even though this is a simplified assumption, a closed-form analytical solution cannot be easily obtained because of the multi-layered system used in the model. An excellent analytical solution for a multi-layered system with a single-phase fluid injection has been reported recently by Selvadurai and Kim (2016).

Mechanical behavior of a deformable porous, homogeneous and isotropic medium can be written as follows (Minkoff et al., 2003; Martinez et al., 2013; Vilarrasa et al., 2014):

(1) Force equilibrium

The force equilibrium of the fluid-filled porous medium can be expressed as

$$\sigma_{ij,j} + f_i = 0 \quad (8)$$

where σ_{ij} is the total stress tensor, and f_i is the body force vector.

(2) Strain–displacement relationships

The gradient of the displacement vector ($\nabla \mathbf{u}$) can be written as (Desai and Siriwardane, 1984; Tran et al., 2005; Vilarrasa et al., 2011):

$$\varepsilon_{ij} = (u_{i,j} + u_{j,i})/2 \quad (9)$$

where ε_{ij} is the strain tensor, and u_i is the displacement vector.

(3) Effective stress calculations

Effective stress can be expressed in terms of total stress (σ_t) and pore fluid pressure (p), as shown below (Biot, 1941; Tran et al., 2005; Huang et al., 2013; Martinez et al., 2013; Alam et al., 2014):

$$\sigma'_{ij} = \sigma_{ij} - \alpha p \delta_{ij} \quad (10)$$

where σ'_{ij} is the effective stress tensor, α is the Biot's coefficient, and δ_{ij} is the Kronecker delta.

(4) Constitutive relation for solid rock

The constitutive equation for the fluid-filled porous medium can be written as (Biot, 1941; Desai and Siriwardane, 1984; Vilarrasa et al., 2011; Siriwardane et al., 2013):

$$\sigma_{ij} = 2G\varepsilon_{ij} + \left(K - \frac{2G}{3}\right)\varepsilon_{kk}\delta_{ij} + \alpha p \delta_{ij} \quad (11)$$

where G is the shear modulus, and K is the bulk modulus.

(5) Porosity changes and coupling details

Geomechanical calculations in the iterative coupling procedure are one step behind the fluid flow calculations (Tran et al., 2005, 2009). Isothermal conditions were assumed in the current modeling study. The computed pressure at the end of every time step in the fluid flow module is passed on to the geomechanics module, which computes stress changes and deformations. The coupling variables (porosity and permeability) calculated in the geomechanics module are sent back to the fluid flow module. The change in permeability as a function of porosity is calculated using the Kozeny–Carman equation (CMG, 2013). The porosity changes computed in the geomechanics module need to be incorporated in the fluid flow module, as shown below (Tran et al., 2005):

$$\frac{\partial}{\partial t} [n_i \rho (1 - \varepsilon_v)] = \nabla \cdot \frac{\rho k}{\mu} (\nabla p - \rho g \nabla z) + q \quad (12)$$

where n_i is the initial porosity, q is the source or sink term, ρ is the fluid density, μ is the fluid viscosity, and ε_v is the volumetric strain.

The volumetric strain, ε_v , accounts for the change in the pore volume and bulk volume of the porous media in the CMG-GEM geomechanics module (Tran et al., 2005). True porosity (n) can be defined as the ratio of current pore volume to current bulk volume of the porous medium, as given below (Tran et al., 2004, 2005):

$$n = \frac{V_p}{V_b} \quad (13)$$

where n is the true porosity, V_p is the current pore volume of the porous medium (m^3), and V_b is the current bulk volume of the porous medium (m^3).

In order to model the changes in volumetric strain with a conventional simulator, the reservoir porosity (n) is defined as a function of initial true porosity (n_i) and volumetric strain (ε_v), as shown below (Tran et al., 2005):

$$n = n_i(1 - \varepsilon_v) \quad (14)$$

In the mathematical formulation, the porosity changes with time due to volumetric strains induced by changes in stress computed in the geomechanics module. Additional mathematical details can also be found in the published literature (Coussy, 2004; Kim et al., 2013).

3.3. Computational models

In the current study, CMG-GEM and ABAQUS computer codes were used to construct the coupled fluid flow and geomechanical models. CMG-GEM is a commercially available finite difference based simulator that can be used to construct multiphase fluid flow models (CMG, 2013). The geomechanics module built in CMG-GEM was used to couple geomechanics with multiphase fluid flow models. Iterative coupling (two-way coupling) methods were used to couple geomechanics with the fluid flow models as reported in the literature (Tran et al., 2009). The data are exchanged back and forth between the flow simulator and geomechanics module. The geomechanics module uses a finite element based approach to independently solve the basic constitutive equations for fluid flow and deformations (Tran et al., 2004, 2005, 2010). ABAQUS is a commercially available finite element code that can handle fully coupled geomechanics with single-phase fluid flow (ABAQUS, 2012). The finite element program ABAQUS has been benchmarked with analytical solutions for coupled fluid flow and geomechanics (Capasso and Mantica, 2006; ABAQUS, 2012; Selvadurai and Suvorov, 2014, 2016; Selvadurai and Shi, 2015). More details about the coupling of geomechanics with flow simulators can be

found elsewhere (Minkoff et al., 2003; Tran et al., 2009, 2010; Vilarrasa et al., 2011; ABAQUS, 2012; CMG, 2013; Siriwardane et al., 2013).

4. Modeling details

The field experiment started in 2002 and was completed in 2003. Details of the pilot scale test are given elsewhere (Westrich et al., 2001; Pawar et al., 2003, 2006) and only a summary is given in this section:

- (1) Injection pressure (bottom hole): 2900 psi (20 MPa);
- (2) Duration of injection: 53 d;
- (3) Total CO₂ injection: 2090 t (1.9×10^6 kg);
- (4) Reservoir pressure long after the injection: 1700 psi (11.72 MPa).

This paper considers CO₂ injection into a depleted oil reservoir, and in this pilot study, the injection rate and injection volume of CO₂ were relatively small and therefore linear elastic behavior was assumed. Moreover, as can be seen later in the results, the area of computed pore pressure change is relatively small compared to the model dimensions and the assumption on linear elastic behavior is reasonable. As such, rock failure was not anticipated (due to low injection rates, pressures, and volumes) and geomechanical factors such as uniaxial compressive and tensile strengths related to rock failure were not considered in the modeling study. The depleted oil reservoir was assumed to be a single-porosity formation without any natural fractures or discontinuities. For sandstone reservoirs, it is reasonable to assume that there are no natural fractures. While natural fractures and discontinuities do play a role in certain reservoirs, these geomechanical factors were not relevant to the current study involving a single-porosity sandstone reservoir.

The boundary and initial conditions assumed for the depleted oil reservoir are shown in Fig. 4. These initial conditions were obtained from the modeling of the depletion process at the field site as reported in the literature (Pawar et al., 2003). Geometric details of layers can be found in Figs. 2 and 3, and Table 1. The geomechanical model was in equilibrium prior to CO₂ injection. Additional mechanical and hydraulic properties used in the modeling work are shown in Table 2. While the initial porosity and permeability were assumed to be 15% and 3.5 mD, respectively, for the reservoir layer, the permeability of all other layers was assumed to be very low (1 μ D). The relative permeability curves used in the study are shown in Fig. 5. The Biot's coefficient was assumed as 1 in this study based on a number of recent published literature (Mathias et al., 2009; Vilarrasa et al., 2013; Rutqvist et al., 2015).

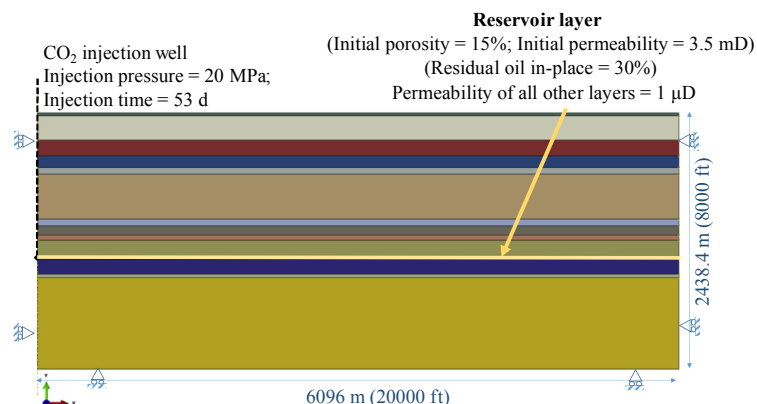


Fig. 4. Assumed initial conditions of the depleted oil reservoir.

Table 2
Reservoir properties.

Reservoir thickness	Initial porosity (%)	Initial permeability (mD)	Initial water saturation (%)	Residual oil in-place (%)	Relative permeability	Rock density	Rock compressibility	Reservoir temperature	Young's modulus	Poisson's ratio	Biot's coefficient
15.24 m (50 ft)	15	3.5	70	30	Fig. 5	2.54 g/cm ³ (158.5 pcf)	3.675 × 10 ⁻⁸ Pa ⁻¹ (2.534 × 10 ⁻⁷ psi ⁻¹)	45.11 °C (113.2 °F)	4.13 × 10 ⁷ kPa (5,988,500 psi)	0.247	1

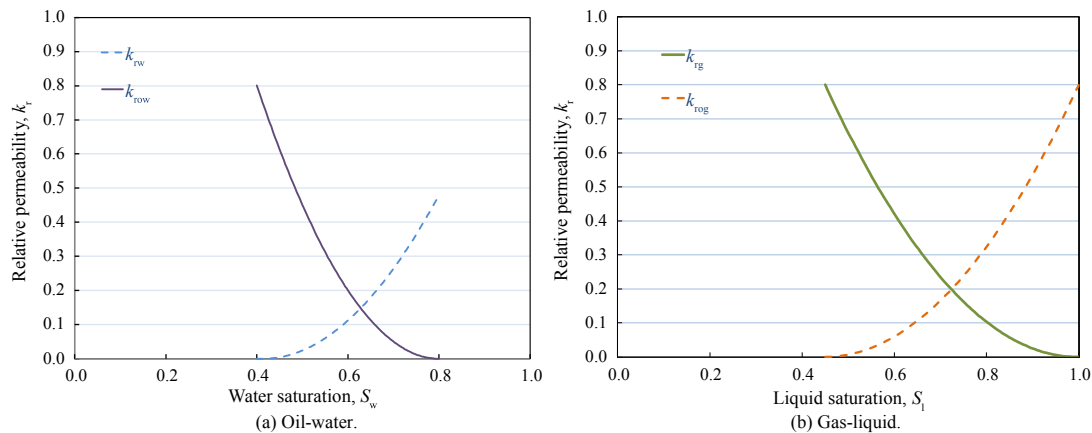


Fig. 5. Assumed relative permeability curves.

Due to radial symmetry, a no-flow boundary condition was assumed at the left boundary of the model. The right boundary was modeled as a no-flow boundary which is far away from the injection point and did not influence the fluid flow and geomechanical response. The fluid pressure was assumed to be hydrostatic initially.

The viscosity and density of CO₂ are calculated internally within the computer code based on the reservoir temperature and pressure by using the Peng–Robinson equation of state (Peng and Robinson, 1976; CMG, 2013). The reservoir temperature was considered as 45.11 °C (113.2 °F) as listed in Table 2. The reservoir pressure changes continuously during CO₂ injection and the density and viscosity values are revised at each time step. The CO₂ viscosity and density at the beginning of the injection are computed as 4.24 × 10⁻⁵ lb/(ft s) (0.0631 cp) and 41.41 lb/ft³ (663.32 kg/m³), respectively. The CO₂ is stored in the reservoir in a supercritical state.

4.1. Coupled single-phase fluid flow and geomechanical modeling

In the general case, with the wide variety of pressures and temperatures that can be found in the subsurface, the density and viscosity of CO₂ can vary widely, and an equation of state can be used to determine the fluid properties (e.g. Poling et al., 2001). In this case, CO₂ is likely to be only slightly compressible at the reservoir depth. For simplicity, the flow of CO₂ was modeled by assuming incompressible single-phase flow (water injection) in this study. Only one component (water injection) was used to model fluid injection. However, in the multiphase fluid flow models (Section 4.2), CO₂ was considered as a compressible fluid according to its equation of state. The problem solved in this section is similar to that of a reservoir compaction during oil or water production, which has been reported in the literature (Geertsma, 1973). In the present study, flow and deformation in a multi-layer system were considered.

A coupled flow-deformation analysis was performed by using the finite element method. Information on rock heterogeneity in the radial direction was not available at the field site and hence the

analysis was carried out using an axisymmetric idealization. The finite element model used in the study is shown in Fig. 6. The lateral extent of the mesh is 6096 m (20,000 ft) and the thickness is 2438.4 m (8000 ft). The finite element mesh shown in this figure consists of quadrilateral elements with linear variation in pore pressure and quadratic variation in displacement. The finite element analysis was performed by prescribing both mechanical and hydraulic boundary conditions. The bottom boundary of the finite element model was fixed and the outside boundary was constrained for displacements in the radial direction. The lateral boundary was selected far from the injection point and did not influence the fluid flow. The bottom boundary was assumed as a no-flow boundary. The bottomhole pressure at the injection well was reported in the literature (Pawar et al., 2003, 2006), but the data on the actual flow rate were not available. The injection was simulated by prescribing the bottomhole injection pressure as a boundary condition. At the field site, the fluid pressure data were the only measurements available and were used in comparisons presented in this paper. The ground displacements were not measured at the field site.

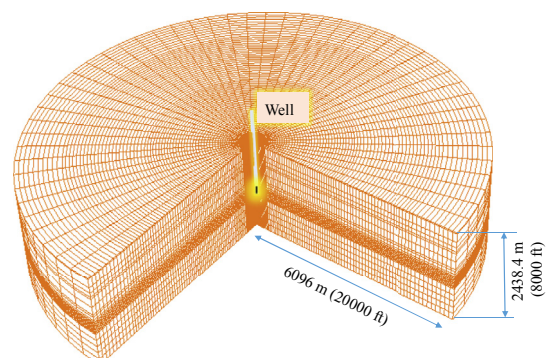


Fig. 6. Geometry of the single-phase finite element model.

The injection was terminated after 53 d. The simulation of fluid flow-deformation was continued for 180 d beyond the termination of injection. The results from the coupled flow-deformation analysis of the CO₂ injection at the West Pearl Queen site indicate that the ground surface deforms during and after the injection. Computed surface deflections are shown in Fig. 7. While the computed magnitudes of the ground deformations in this pilot test are very small, the computed results show the possibility of heaving of the ground depending upon the amount of injected CO₂. Fig. 7 shows the spatial distribution of the surface deformation that occurs at the end of injection, and post-injection. As the pressure is redistributed within the subsurface formations, which depends on the permeability field, it will have a significant effect on surface deformations.

As can be seen from Fig. 7, the computed surface deformations drop rapidly after the termination of CO₂ injection. This is caused by the continued flow of fluids through the reservoir due to the pressure gradient that exists after the completion of injection. The permeability and elastic properties of the geologic formations would have a significant influence on the reservoir response after injection. As can be seen from this figure, the computed surface displacements spread over a large area outside the injection well. These displacements may be useful in indirect estimates of the CO₂ plume underground. The analysis did not consider the influence of natural fractures that may exist in the reservoir. The pressure decline data, as well as measured surface deformations, could be

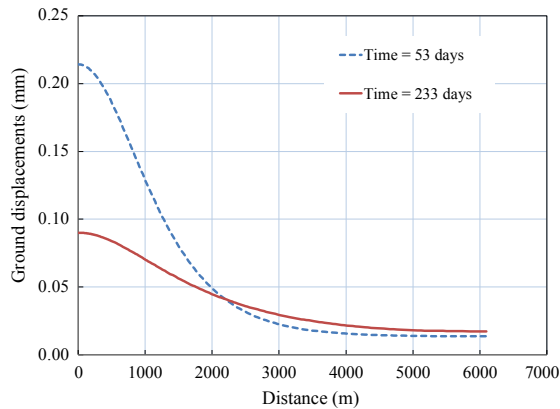


Fig. 7. Computed surface displacements by using coupled single-phase fluid flow and deformation model.

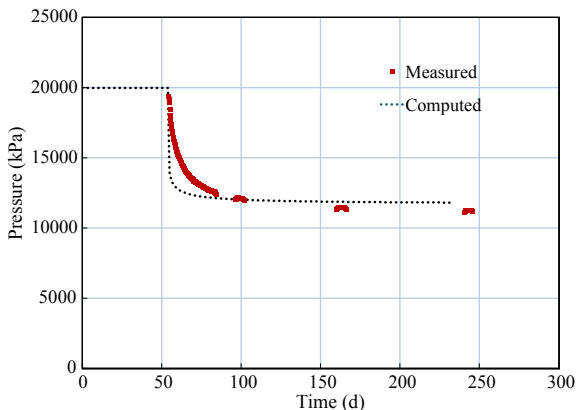


Fig. 8. Variation of fluid pressure with time by using a coupled single-phase fluid flow and deformation model.

used to adjust the engineering parameters used and to calibrate the model, which can then be used for subsequent predictions.

Fig. 8 shows the pressure decline curves after the termination of fluid injection. While the model predictions were similar to experimentally observed data, the comparison of computed and measured data cannot be considered excellent. Therefore, an effort was undertaken to perform multiphase fluid flow analysis coupled with geomechanics.

4.2. Coupled multiphase fluid flow and geomechanical modeling

To perform multiphase flow simulation, an advanced compositional and greenhouse gas simulator integrated with geomechanics module was used (CMG, 2013). The program is a commercially available multiphase flow simulator, provided by CMG (2013). The simulator incorporates geomechanics to compute stress and displacement changes by using iterative coupling methods as discussed in the literature (CMG, 2013; Tran et al., 2004, 2009, 2010). Previous modeling work of the study area includes flow simulations without geomechanics (Pawar et al., 2006). These fluid flow models simulate the reservoir behavior before and after CO₂ injection. In the current paper, geomechanical effects were

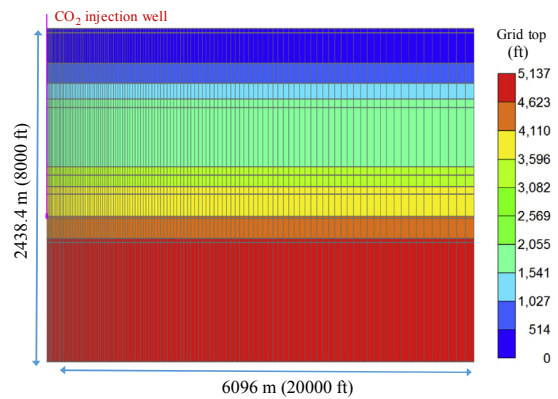


Fig. 9. Geometry of the coupled multiphase fluid flow and geomechanical model.

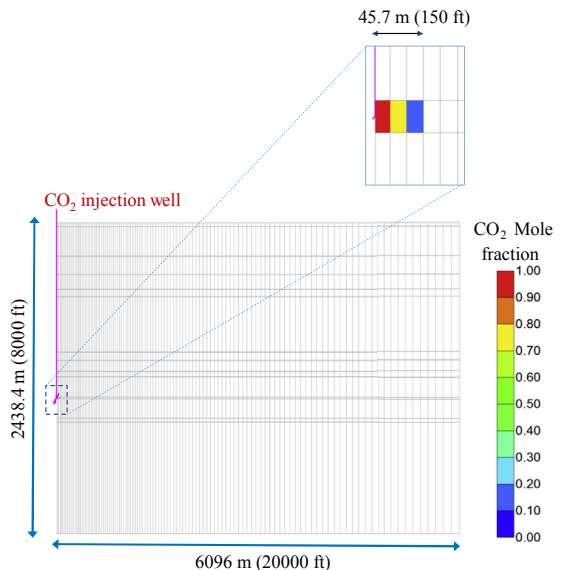


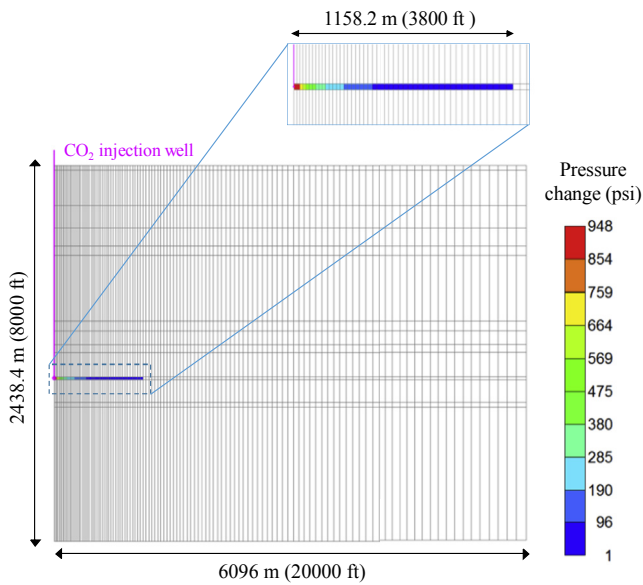
Fig. 10. CO₂ mole fraction at the end of injection by using a coupled multiphase flow and geomechanical model.

incorporated in the modeling study. Fluid pressure and ground deformations were computed during and after CO₂ injection. Previously reported pre-injection modeling studies (Pawar et al., 2003, 2006) were used to determine the initial conditions of the reservoir to simulate CO₂ injection.

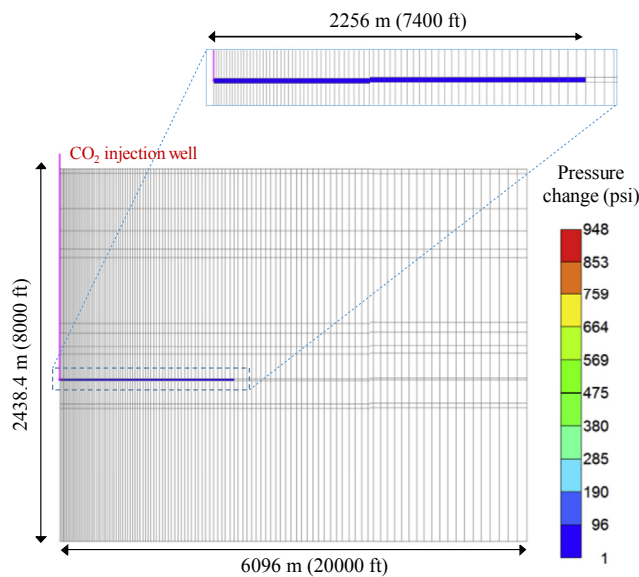
Usually, CO₂ injected will reach the storage formation at a lower downhole temperature than that of the reservoir (Vilarrasa et al., 2013, 2014). The colder temperature increases CO₂ density and lowers pressure buildup near the injection region. In the long term, the temperature of injected CO₂ will reach the formation temperature. Isothermal conditions were considered in the modeling study reported in this paper and it was assumed that the temperature of CO₂ reaching the targeted reservoir layer is the same as the formation temperature.

An axisymmetric model was used to investigate the multiphase flow and geomechanical behavior during CO₂ injection. Fig. 9 shows a cross-section of the axisymmetric model, which is geometrically identical to the single-phase fluid flow model. This model uses a single porosity system with 118 grid blocks in the radial direction. The dimensions of grid blocks vary with refined grid blocks near the injection well to coarser grid blocks near the model boundaries. The model consists of 13 layers with shale acting as the caprock layer for the reservoir. Table 1 shows the geometric details and geomechanical properties of the model. Table 2 shows the reservoir properties assumed in this study. A vertical injection well penetrating through the reservoir layer was used to inject CO₂ at 20 MPa (2900 psi). The initial reservoir pressure was assumed as 11.72 MPa (1700 psi). The CO₂ injection was carried out for 53 d, and the simulations were continued for additional 180 d beyond the 53-d injection period.

Fig. 10 shows the computed CO₂ mole fraction at the end of 53-d injection period. Modeling results show that CO₂ flow is limited near the injection zone during injection and post-injection periods. Fig. 11a and b shows the computed changes in fluid pressure at the end of 53 d of injection and 180 d of post-injection, respectively. The computed changes in fluid pressure are the largest near the injection point during the injection period, and the area of

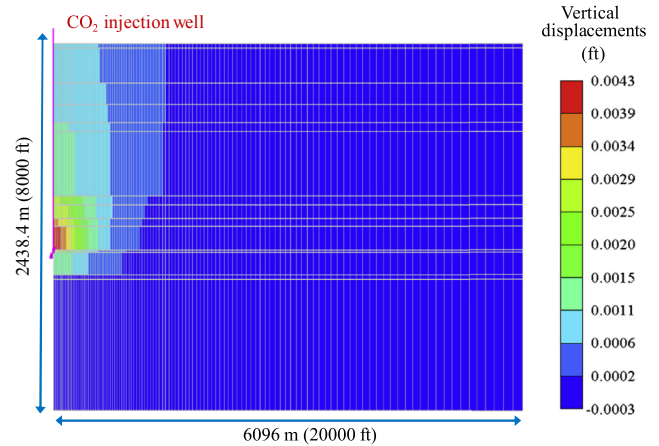


(a) After 53 d of CO₂ injection.

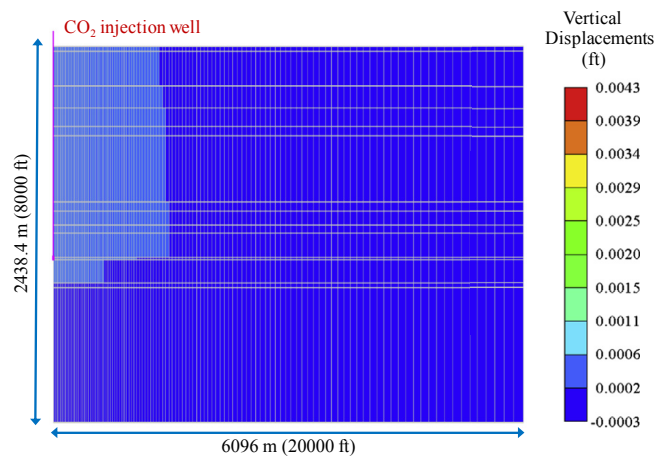


(b) After 180 d of post-injection.

Fig. 11. Computed fluid pressure changes for the coupled multiphase flow and geomechanical model.



(a) After 53 d of CO₂ injection.



(b) After 180 d of post-injection.

Fig. 12. Computed vertical displacements for the coupled multiphase flow and geomechanical model.

influence is relatively small compared to the model dimensions. Therefore, the assumption on linear elastic behavior for this case is reasonable. As CO₂ moves in the reservoir layer during post-injection, some changes in fluid pressures can be seen far away from injection zone. Fig. 12 shows the computed vertical displacements at the end of the injection and post-injection periods. Modeling results show a maximum ground displacement of 0.24 mm (0.008 ft) at the end of 53 d of injection. The maximum ground displacement drops to 0.09 mm (0.0035 ft) at the end of 180 d of post-injection period.

The results presented in this section were based on the assumed relative permeability curves shown in Fig. 5. The influence of relative permeability on the fluid pressure response was investigated by considering the following three cases of relative permeability curves:

- (1) Case 1: Relative permeability curves shown in Fig. 5;
- (2) Case 2: Relative permeability curves published in Hosseini and Nicot (2012); and
- (3) Case 3: Relative permeability curves published in Fung et al. (1994).

Fig. 13 shows a comparison of the relative permeability curves for these three cases. As can be seen from Fig. 14, the curvature of the computed fluid pressure curves is significantly influenced by the oil-water relative permeability. Modeling results corresponding to Case 1 can be considered as a good match with the measured data. The capillary pressure is not considered in modeling of sandstone reservoirs suitable for CO₂ storage because the capillary

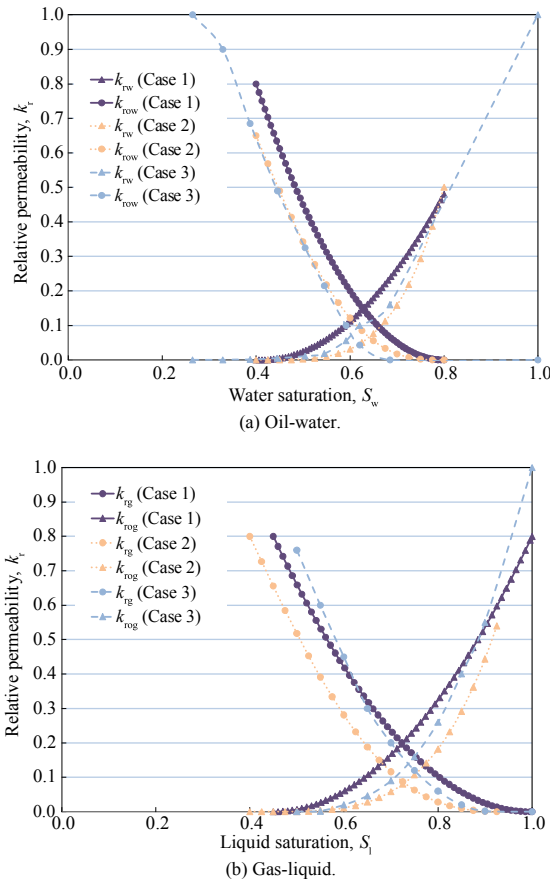


Fig. 13. Comparison of relative permeability curves.

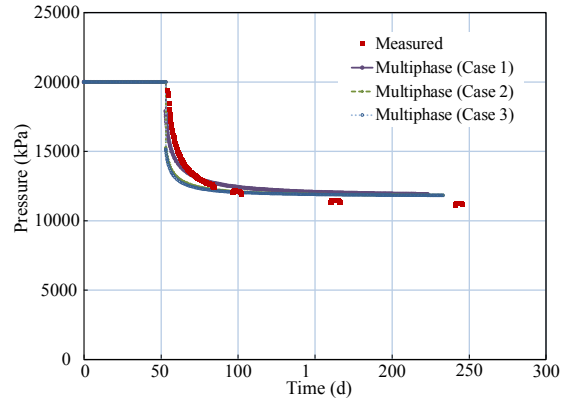


Fig. 14. Influence of relative permeability on fluid pressure response.

pressure is very small compared with operational reservoir fluid pressures.

5. Comparison of single-phase and multiphase modeling coupled with geomechanics

The modeling results from coupled single-phase fluid flow-deformation analysis and coupled multiphase fluid flow-deformation analysis were compared with available measured data. At the field site, the fluid pressure data were the only measurements available and were used in the comparisons presented in this paper.

The ground displacements were not measured at the field site. Fig. 15 shows a comparison of changes in fluid pressure for single-phase and multiphase modeling with available fluid pressure data during injection and post-injection periods. Modeling results from multiphase fluid flow analyses show that changes in fluid pressure match well with available measured data. Single-phase fluid flow modeling results are comparable to, but do not match well with measured data. However, the modeling results from single-phase fluid flow analyses can be fine-tuned to obtain a better match with measured data by changing a few reservoir and geomechanical properties. When the fluid is injected with a constant bottomhole pressure in both single-phase (i.e. water injection) and multiphase (i.e. CO₂ injection) fluid flow models, modeling results from a previous study (Siriwardane et al., 2013) show lower values of computed pressure in the case of single-phase fluid flow than the pressure values computed from the multiphase fluid flow model. Because of the high viscosity of water compared to that of CO₂, the

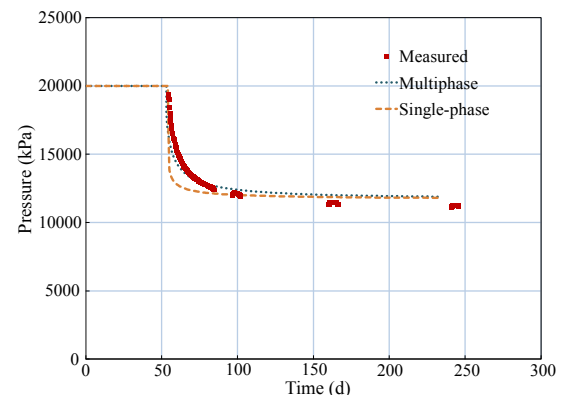


Fig. 15. Comparison of measured and computed changes in fluid pressure.

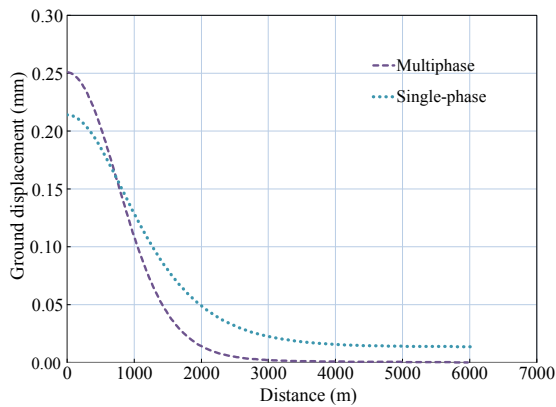


Fig. 16. Comparison of computed ground displacements at the end of injection by using a coupled single-phase and multiphase fluid flow models with geomechanics.

amount of fluid injection is low in the case of single-phase fluid flow. In the case of multiphase fluid flow models, the amount of CO₂ injection volume is larger because of its low viscosity. Fig. 16 shows a comparison of computed ground displacements at the end of injection for single-phase and multiphase fluid flow modeling coupled with geomechanics. Since there were no actual measurements of ground displacements at the field site, only modeling results are included in Fig. 16. Computed ground displacements from the single-phase analyses match well with the values from the multiphase fluid flow modeling coupled with geomechanics. Single-phase model predictions of the maximum surface displacement are about 14% lower than the multiphase predictions. Coupled single-phase fluid flow and geomechanics models can be used to predict approximate magnitudes of ground displacements. However, the fluid pressure response from a single-phase model cannot be considered as a good match with measured data in this case. Furthermore, a poroelastic analysis of the medium subjected to fluid injection/fluid extraction can also be used to obtain engineering estimates of ground displacements as shown in the literature (Geertsma, 1973; Selvadurai, 2009; Kim and Selvadurai, 2015; Selvadurai and Kim, 2015).

As evident from Fig. 15, the single-phase fluid flow model coupled with geomechanics does not provide a good match to the measured fluid pressure. Monitoring of subsurface fluid pressure and ground deformation response at a few selected points could help infer reservoir properties that could aid in the prediction of future CO₂ front propagation. Methods to determine reservoir properties based on inversion methods have been described in the literature (Vasco et al., 2001). Even though the single-phase fluid flow model coupled with geomechanics does not provide a good match to the available measured data at the field site, it is a simpler model compared with the multiphase fluid flow model coupled with geomechanics. However, the advantage of the single-phase fluid flow model coupled with geomechanics is that it can be used to obtain approximate values with a significantly lower computational effort. Changes in rock stresses caused by fluid injection can lead to shear failure in rocks, opening of faults, and may, in extreme cases, cause failure of the wellbore. Such factors need to be incorporated into future coupled flow and geomechanical analyses to better understand their significance, which will be helpful in site selection and risk assessment protocols.

6. Conclusions

Only a few coupled fluid flow and geomechanical modeling studies have been carried out at field sites combined with

monitoring techniques to understand the geomechanical response to the injection of CO₂ into deep geologic media. The novelty of the research study presented herein is the modeling of coupled multiphase fluid flow and geomechanics of CO₂ injection into a depleted oil reservoir. A computational modeling study was performed to investigate the fluid pressure and ground deformations at the West Pearl Queen depleted oil reservoir site during CO₂ injection. A field experiment had been conducted at the site, and the available data from this experiment were used as inputs for the modeling study. Both single-phase and multiphase fluid flow analyses coupled with geomechanics were carried out, and modeling results were compared with available measured data. The site geology and the material properties determined on the basis of available geophysical data were used in the analyses. Modeling results from the coupled multiphase fluid flow and geomechanical analyses show that the computed fluid pressure matches well with available measured fluid pressure data. The relative permeability curves used in the multiphase fluid flow models have a significant influence on computed fluid pressure distribution and ground deformations. While the multiphase fluid flow models provide more accurate fluid pressure response, approximate solutions can be obtained by using single-phase fluid flow models. Single-phase model predictions of the maximum surface displacement are about 14% lower than the multiphase predictions at this experimental site under the considered conditions. The single-phase fluid pressure response does not agree well with the pressure computed in multiphase models. The advantage of a single-phase model, however, is the simplicity. Limited field monitoring of subsurface fluid pressure and ground surface deformations coupled with computational models, such as those presented in this paper, could be used for investigating the performance of large-scale CO₂ storage in depleted oil reservoirs.

Conflict of interest

The authors wish to confirm that there are no known conflicts of interest associated with this publication and there has been no financial support for this work that could have influenced its outcome.

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