Non-isothermal Flow of CO2 in Injection Wells: Evaluation of Different Injection Modes

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Abstract

During the injection of carbon dioxide, the fluid density within the injection pipe could vary significantly along the well in response to pressure and temperature variations, thus affecting the CO2 injection rate at the reservoir depth. Flow of CO2 in non-isothermal wells involves solving the partial differential equations (PDE) that express energy, mass and momentum conservation. These PDEs are coupled through equations of state governing fluid and thermodynamic properties (Lu and Connell, 2008; Paterson et al., 2008; Han et al., 2010; Pan et al., 2011; Sponagle et al., 2011).

Here, a 1D model of non-isothermal single-phase flow of CO2 through an injection well is developed following the approach of Lu and Connell (2014), in which the flow equations are based on the averaged-flow model (Hasan and Kabir, 2002). The model has been implemented in COMSOL Multiphysics® through the coefficient's form of the PDE module with multiple dependent variables.

Seven simulations were run to study different CO2 injection conditions at the wellhead: gas, gas and liquid near the critical point (CP), supercritical (SC) (8 and 10 MPa), liquid at high P and T, liquid at low P and T (Figure 1). The energy consumption due to surface conditioning operations varies for each injection mode and can be roughly estimated by the difference of specific enthalpy between wellhead and storage vessel conditions (Vilarrasa et al., 2013). Figure 1 shows the energy consumption for each injection mode (storage vessel at 2.0 MPa and -20 °C; injection flowrate of 1 kg/s). It is higher when injecting CO2 in gas-phase, near critical and SC conditions at the wellhead. On the contrary, injecting CO2 in liquid-phase reduces substantially the energy consumption because pumping/compression is easier and heating is minor.

Figure 2 shows the temperature, pressure, velocity and density profiles obtained in steady state for each injection mode. Injecting gaseous CO2 causes very low densities through the wellbore. CO2 injection in gaseous near the CP and SC (8 MPa) conditions increase density but at the bottom this is still lower than 600 kg/m3. By contrast, injecting liquid near the CP and SC (10 MPa) conditions lead to higher bottomhole densities, comparable to those reached by injecting liquid CO2. Higher CO2 densities are advantageous because are closer to the density of the resident brine, which reduce buoyancy effects in the reservoir and the potential risks of caprock failure and subsequent CO2 leakages. Secondly, transient simulations reveal that steady state is reached faster by injecting at higher pressures. In particular, steady state flow conditions are

obtained after 1 hr when injecting SC CO_2 at the wellhead (Figure 3). On the contrary, operational equilibrium is reached only after 100 days by injecting gaseous or liquid CO_2 at low pressure (Figure 4).

It is concluded that CO_2 injection conditions should be tuned considering a balance between optimal storage densities and the stability of the operation. The present model could also be used to evaluate injection strategies with dynamic wellhead conditions, or to determine operational conditions leading to undesired blowout episodes.

Reference

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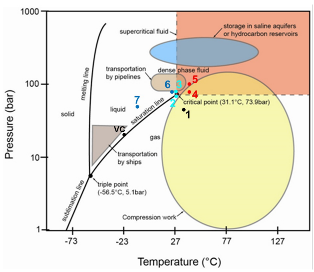
Figures used in the abstract



	Injection conditions	P, MPa	T, °C	Compression work, kW
1	Gas	4.5	35	305.7
2	Gas near CP	7.0	31	245.4
3	Liquid near CP	8.0	31	125.8
4	Supercritical	8.0	40	241.3
5	Supercritical	10.0	40	146.6
6	Liquid	8.0	25	103.1
7	Liquid	5.0	-10	19.66

CP: critical point
VC (vessel conditions): -20 ºC, 2.0 MPa

Figure 1: CO2 phase diagram: pipeline transportation is done in liquid conditions and geological storage stays in supercritical conditions (left). The table (right) summarizes seven different injections conditions and the associated energy consumption assuming that CO2 is stored in vessels at -20 °C and 2.0 MPa and the injection flowrate is 1.0 kg/s

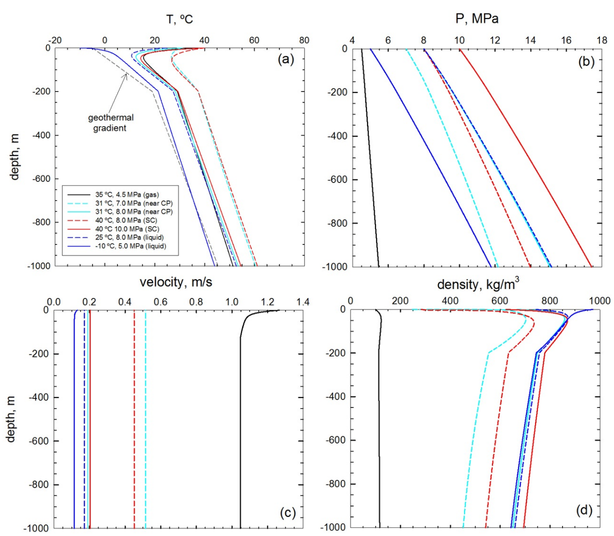


Figure 2: Non-isothermal flow of CO2 through an injection well. Comparison of different injection modes: temperature (a), pressure (b), velocity (c), and density (d) profiles in steady state. (Injection flowrate = 1.0 kg/s; diameter of injection pipe = 0.1 m; overall heat transfer coefficient = 4.0 W/m2-K)

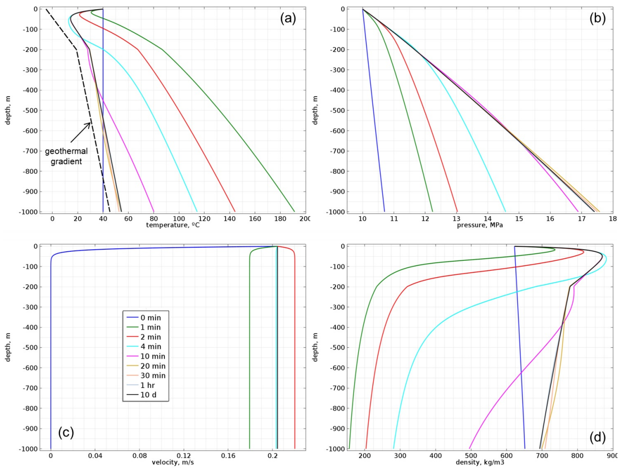


Figure 3: Non-isothermal flow of CO2 through an injection well. Evolution of temperature (a), pressure (b), velocity (c), and density (d) profiles. CO2 is injected at 1.0 kg/s in SC conditions at the wellhead (40 °C and 10 MPa). Steady state is reached after 1.0 hr.

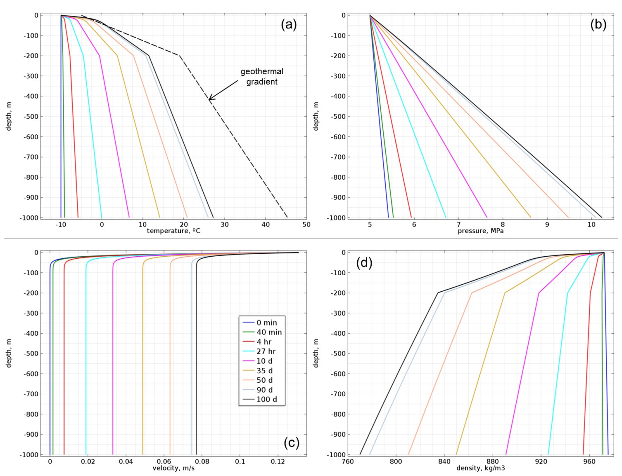


Figure 4: Non-isothermal flow of CO2 through an injection well. Evolution of temperature (a), pressure (b), velocity (c), and density (d) profiles. CO2 is injected at 1.0 kg/s in liquid conditions at the wellhead (-10 °C and 5 MPa). Steady state is reached after 100 days.