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Thermal Modelling in and around a CO₂ Injector

Binglu Ruan\textsuperscript{a}, Ruina Xu\textsuperscript{a}, Lingli Wei\textsuperscript{b}, Peixue Jiang\textsuperscript{a,*}

\textsuperscript{a}Beijing Key Laboratory of CO₂ Utilization and Reduction Technology, Department of Thermal Engineering, Tsinghua University, Beijing, P R China, 100084
\textsuperscript{b}Shell (China) Innovation and R&D Centre, Beijing, P R China, 100004

Abstract

During the injection, due to significant changes in pressure and temperature conditions from wellhead and bottomhole of a CO₂ injector, and transient effects in pressure and temperature during start-up and shut-in, CO₂ may go through complex phase changes both in space and in time. This paper predicted the temperature and pressure variations in and around the wellbore in both steady-state and transient conditions by a two-dimensional radial wellbore flow model with considerations of CO₂ in injection well, fluids in annulus, surrounding rocks and the storage reservoirs. Transport and thermal behaviours of CO₂ and its impact on surrounding fluids and rocks are investigated by solving the mass equation, momentum equations and energy equations. Temperature profile of CO₂ in tubing variation with injection time and its impact on those of water in annulus and surrounding rocks are explored. The mechanism of the increment of CO₂ temperature along the tubing is investigated. Moreover, the transient well shut-in effects on the pressure and temperature profile of CO₂ are predicted. The results provide basis for risk mitigations related to potential icing at the wellhead due to cooling during sudden shut-in and restart of injection for offshore projects.

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Keywords: Supercritical CO₂; Natural convection; Shut-in effect; Wellbore flow

1. Introduction

Geological sequestration of CO₂ is a promising solution to reduce net emissions of greenhouse gases into atmosphere. Saline aquifers and depleted oil and gas reservoirs are usually adopted as important targets for CO₂ storage. During the injection, due to significant changes in pressure and temperature conditions from wellhead and bottomhole of a CO₂ injector, and transient effects in pressure and temperature during start-up and shut-in, CO₂ may go through complex phase changes accompanied by

* Corresponding author. Tel.: +86-10-62772661; fax: +86-10-62770209.
E-mail address: jiangpx@tsinghua.edu.cn.
significant density, heat capacity, thermal conductivity and viscosity variations spatially and temporally. Heat exchange with the surrounding rocks from overburden to the reservoir / aquifer will have significant impact on the processes. Fluids in the annulus of the wellbore also play a role.

The flow and thermal behaviour of CO₂ in the subsurface during the injection process has been investigated by many researchers [1-3]. The researchers at Lawrence Berkeley National Laboratory in USA developed a series of simulators to predict the flow inside a reservoir [3]. For the wellbore prediction, engineers in gas and oil industry usually adopted empirical correlations to model the pressure drop of hydrocarbon (oil, gas and water) in wellbores [4]. Other researchers also developed one-dimensional multiphase model for wellbore flow simulations of hydrocarbon [5]. However, when the injection switches to carbon dioxide for the purpose of carbon sequestration, those correlations and models may fail to predict accurately due to the significantly different fluid properties of CO₂.

In this paper, a two-dimensional radial wellbore flow model with considerations of CO₂ in injection well, fluids in annulus, surrounding rocks and the storage reservoirs is established. Flow and thermal behaviours of CO₂ and its impact on surrounding fluids and rocks are investigated by solving the mass equation, momentum equations and energy equations. The bottomhole temperature and the wellhead pressure behaviour with injection time are predicted. The effect of natural convection of the fluid in annulus on thermal behaviour of CO₂ is analyzed. Moreover, with the combined wellbore and reservoir flow model, the transient effects on temperature changing inside the tubing during and after the well shut-in are predicted. This paper is the first in its kind of modeling the CO₂ flow from wellhead to the injection target formation with full physics, predicting the temperature and pressure variations in and around the wellbore in both steady-state and transient conditions. The results provide basis for risk mitigations related to potential icing at the wellhead due to cooling during sudden shut-in and restart of injection for offshore projects.

2. Numerical Methods

2.1. Physical Models

Fig. 1. Schematic diagram of the simulation model and dimensions
Figure 1 shows the schematic diagram of the simulation models. It is assumed that the flow and temperature variations on the circumferential direction of the well are neglected. Hence, the 3D physical model can be reduced into a 2D radial model as shown in Fig. 1. To analyze the effect of the storage reservoirs on the CO₂ thermal behaviour inside the tubing, two physical models are used to do the simulation. Model 1 without the storage reservoir part is as shown in Fig. 1(a), and Model 2 with the storage reservoir part is as shown in Fig. 1(b). All the other parameters are all same between the two models. Therefore, Model 2 is chosen to be introduced below. The CO₂ is injected through the wellbore, gravel pack and into the reservoir. Between the tubing and the rocks, water is filled in annulus. The dimensions of the well are also labeled in Fig. 1(b). The well has a total depth of 2500 m. At the well bottom, the diameter of the tubing narrows from 0.127 m to 0.076 m. The radius of the model is set to be 1000 m to try to consider the impact of the infinitely large surrounding rocks on the CO₂ flow. The top surface of the model is set at 4°C representing temperature at the sea bed of the North Sea, and the bottom is 80°C. The injection parameters and other formation data are listed in Table 1. Comparing the depth of the wellbore, the reservoir is 100 m deep. According to the different permeability, the reservoir domain in the model is divided into three parts (see the enlarged view of reservoir in Fig. 1(c)). The permeability for the Part 1 (wellbore), Part 2 (near-field) and Part 3 (far-field) is $10^5$ Darcy, 5 Darcy and 4 mDarcy, respectively. The porosity for Part 1, Part 2 and Part 3 is 100%, 40% and 20%. It should be noted that Part 1 is redeemed as porous media with a very large permeability and a porosity of 100% for numerical considerations. The reservoir has an initial constant temperature of 80°C and an initial linear pressure increment from 19.6 to 20.2 MPa with the depth. CO₂ flow of single phase is simulated in the reservoir. Some other injection information and formation data are provided in Table 1.

Table 1 Injection parameters and formation data

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injection Flow rate</td>
<td>1500 ton/day</td>
</tr>
<tr>
<td>Injection Temperature</td>
<td>4°C</td>
</tr>
<tr>
<td>Bottomhole Pressure/ Reservoir Pressure</td>
<td>27 MPa</td>
</tr>
<tr>
<td>Density of Rock</td>
<td>2600 kg/m³</td>
</tr>
<tr>
<td>Specific Heat of Rock</td>
<td>1000 J/kg·K</td>
</tr>
<tr>
<td>Thermal Conductivity of Rock</td>
<td>2.51 W/m·K</td>
</tr>
<tr>
<td>Geothermal Gradient</td>
<td>0.0304°C/m</td>
</tr>
<tr>
<td>Tubing Roughness</td>
<td>0 μm, 15.24 μm, 53.34 μm</td>
</tr>
</tbody>
</table>

2.2. Simulation grid

The grids are generated using Gambit 2.2. Quadrangular grids are employed. The computational domain for the wellbore simulation (Model 1) is divided into four parts: rock, water in the annulus, CO₂ in the tubing, and CO₂ below packer. According to the injection flow rate, Reynolds number of CO₂ is around $1.7 \times 10^6$, which indicates the flow is turbulent. In the radial direction, to accurately model the heat transfer between CO₂ and formation, the grids adjacent to the interface of the CO₂ domain and the water domain are refined to satisfy the desired $y+$ value (dimensionless wall distance) required by the turbulent model and near-wall treatment. Along the axial direction of the tubing, one grid takes 1 m. This size is quite large comparing to the radial size of a grid. However, after grid independent studies, which compared the CO₂ pressure and temperature profile with the grid size of 0.1 m and 0.01 m, it is found that further reduction in grid sizes in the axial direction of tubing does not have significant effects on the CO₂ pressure and temperature profiles in wellbore. The total number of grids of the whole computational domain is $2.1 \times 10^5$. For the reservoir part, the grids in the axial direction take 0.1 m. After grid
independent studies, it is found that further reduction in grid sizes does not have significant effects on the CO₂ pressure and temperature profile in both wellbore part and reservoir part. The number of grids in the total computational domain is $5.4 \times 10^5$. 

2.3. Governing equations and computational methods

The commercial computational-fluid-dynamics codes, FLUENT in ANSYS 13, based on finite volume method was utilized to translate the coupled and partial differential continuity, momentum and energy equations into algebraic expressions. The coupling between pressure and velocity is implemented by the SIMPLEC (Semi-Implicit Method for Pressure Linked Equations Consistent) algorithm for steady calculation and PISO (Pressure-Implicit with Splitting of Operators) algorithm for transient/unsteady calculation. The Green-Gauss Cell Based gradient is used as the spatial discretization scheme. A second-order upwind scheme is adopted to discretize the governing equations. The “PRESTO!” (PRESsure Staggering Option) scheme is employed to discretize the pressure.

The flow is turbulent before it reaches the reservoir. The k- turbulence model along with a standard wall function is employed for the wellbore flow. For the reservoir flow, the laminar model is adopted. To calculate the transient shut-in effect, the mixture two-phase model is used. The mass transfer coefficient for the two-phase model should be determined from the data of field studies. To the authors’ best knowledge, the data is currently unavailable from the open literatures. Since the purpose of this study is to provide a qualitative trend of the phenomena, hence, the default value in ANSYS-FLUENT is used.

2.4. Fluid properties

The fluid properties are one of the key factors to the calculation. For CO₂ at the subcritical or supercritical phase, the fluid properties varies significantly with pressure and temperature, and it also have important impact on the pressure and temperature profile of the CO₂ in well. In this calculation, the real-gas fluid properties of CO₂ are employed. The density of CO₂ is calculated using the Peng-Robinson equations, which is commonly-used in the petroleum oil and gas industry [6]. The specific heat of CO₂ is calculated using the departure-function method [7]. The thermal conductivity and dynamic viscosity of CO₂ are calculated by correlations piecewise-fitted using the data from NIST (National Institute of Standards and Technology, USA) Chemistry WebBook. The accuracies of the fitting correlations are within 2.5% for thermal conductivity and 1.8% for viscosity. To investigate the effects of natural convection of water in the annulus on the transport and thermal behaviour of CO₂ in tubing, the density, specific heat, thermal conductivity and viscosity of water are also calculated by curved-fitted correlations with data from NIST Chemistry WebBook.

3. Results and discussions

3.1. Thermal and flow behaviour with injection time

Figure 2 shows the bottomhole temperature and wellhead pressure plotted against the injection time. They are also compared with the calculation results between the two models. It can be seen that the wellhead pressure decreases significantly in the first day of injection, then it increases slightly with injection time, and finally approaching 5 MPa at the injection time of 1 month. This behaviour is a little different from that obtained for CO₂ wellbore flow only. The wellhead pressure for calculation with wellbore only decreases significantly on the first day of injection, then it continues decreasing very slowly, and finally reaching 4.6 MPa at the injection time of 1 month. However, the bottomhole
temperature for calculations with and without reservoir agrees excellently with each other. The different
behavior in wellhead pressure is due to the flow resistance of CO₂ in reservoir. With an increased
injection time, the temperature of CO₂ at the bottom of the well and in reservoir decreases. For calculation
of combined wellbore flow and reservoir flow, the pressure balance of CO₂ can be expressed as:

\[ P_{WH} + P_{hydro} = P_{fric} + P_{BH} + P_{res} \]  \hspace{1cm} (1)

where \( P_{hydro} \) is the hydrostatic pressure of CO₂ in wellbore, \( P_{fric} \) is the pressure lost caused by friction, \( P_{res} \) is the pressure drop when CO₂ flow across the reservoir. As the temperature of CO₂ in reservoir decreases, the viscosity increases. According to Darcy’s law, \( P_{res} \) increases slightly. Hence, \( P_{WH} \) increases as well.

3.2. The mechanism of CO₂ temperature increasing along the tubing

Three factors will lead to an increase in the bottomhole temperature comparing to the injection
temperature for an injection of subcritical or supercritical CO₂ in a vertical well:

(1) The enthalpy increase with respect to work done by pressure and volume change of a fluid element
(named as the factor of “compressibility”, shown as the second term at right of Eq.(2)):

\[ dh = c_p dT + \left[ v - T \frac{\partial v}{\partial T} \right] dp \]  \hspace{1cm} (2)

(2) The potential energy;
(3) The heat exchange with surrounding formation (water in annulus and rock).

It should be noted that the effect of natural convection of water may increase the heat transfer rate, and
also lead to an increase in the bottomhole temperature comparing to that with immobile water. In order to
distinguish this effect, the natural convection of water is redeemed as the fourth factor contributing the
bottomhole temperature increase in this report.

Four cases are studied to obtain the percentage of these factors that contributes to the total bottomhole
temperature increase: (a) CO₂ is injected into an adiabatic tubing with the consideration of the factor of “compressibility” only; (b) CO₂ is injected into an adiabatic tubing with consideration of both “compressibility” and potential energy; (c) Based on (b), the heat exchange with surrounding formation is also considered, however, the water in annulus is immobile with thermal conductivity of 0.6 W/m·K; (d) Based on (b), the heat exchange with surrounding formation is considered, and natural convection of water is also included in the simulation (denoted as the “real situation”). As discussed in Section 3.1, the differences of the prediction of thermal behaviour in CO₂ tubing between the Model 1 and Model 2 is quite small, therefore, the Model 1 is used in this part to do the analysis.

Figure 4 shows the factors and their portion contribution to the bottomhole temperature increase over
the injection temperature. By comparing the bottomhole temperature for case (a)-(d) in Fig. 3, it can be
seen that the total temperature increase of CO2 during the injection process is 27.9 °C, where the compressibility factor contributes 9.5 °C, the potential energy contributes 11.8 °C, the heat exchange between CO2 and surrounding rocks though immobile water contributes 4.8 °C, and the natural convection of water enlarges contribution of heat exchange to 6.6 °C. The percentage of the factors resulting in the increase in the bottomhole temperature of CO2 can be seen more clearly in Fig. 4. It can be seen that the potential energy is the leading factor resulting in the increase of the bottomhole temperature (42.31%). The compressibility takes the second factor (34.1%). Both of them contribute around 76% of the increase in the bottomhole temperature. It should be also noted that the natural convection of the mobile water contributes 6.38% of the increase in bottomhole temperature. If an accurate simulation is required, the factor of natural convection can’t be ignored. Although the natural convection of water in the annulus contributes the least among the factors leading to the CO2 bottomhole temperature increase in our study, the effect of the natural convection may also depend on other factors, such as the CO2 temperature distribution along the wellbore, the rock temperature gradient, the diameter/the space of the annulus, the annulus inclination angle, etc. Further investigation needs to be done in this area in the future.

3.3 Wellbore transient shut-in effect

Figure 5 shows the transient effects on thermal and flow behaviour of CO2 after the well is shut-in within 3s, 5s, 10s, 30s and 60s using Model 2. Due to the compressibility, the decrease of mass in tubing results in a decrease in wellhead pressure, which can be observed in Fig. 5(a). The calculation results show that the wellhead pressure reaches the minimum of 3.1 MPa at around 5 min, and then recovered very slightly. The slight recover in wellhead pressure may be due to the reduced hydraulic pressure caused by the increase in the CO2 temperature, which can be seen in Fig. 5(b). The bottomhole temperature, as well as the temperature of CO2 in tubing, is increased due to the reduced mass flow rate. Therefore, the density of CO2 in tubing is decreased and the hydraulic pressure decreases. It can be seen that within the shut-in of 5 min, the decrease in hydraulic pressure is less than that in bottomhole pressure, and hence, a reduced wellhead pressure is observed. However, after 5 min, the decrease in hydraulic pressure is slightly over the decrease in the bottomhole pressure. This may be the reason of the slight pressure recover at wellhead after shut-in of 5 min.

Figure 6(a) shows the temperature behaviour with time during and after wellbore shut-in at the well depth of 0.5 m (from seabed). Due to the decrease in wellhead pressure, the temperature adjacent to the wellhead decreases. The temperature at 0.5 m goes down to a minimal of around −3°C after the well is
shut-in around 5 min. Before 5 min, the shorter the shut-in time, the lower the CO₂ temperature. However, when the time is approaching 5 min, there is almost no difference in the minimum temperature with different shut-in time. It can be also seen that after 5 min, the temperature of CO₂ recovers gradually.

Figure 6(b) shows the temperature behaviour with time during and after wellbore shut-in at the well depth of 50 m (from seabed). The pressure and temperature behaviour is similar with that observed in Fig. 6(a); however, the minimum pressure and temperature are different. The minimum temperature at a deep well location (50 m) is higher than that at a shallow well depth (0.5 m). This means the temperature adjacent to the wellhead is easier to fall down to a subzero degree after the well is shut-in. Hence, the wellhead area has the highest risk of frozen during and after the well shut-in. It can be also seen from Fig. 6 (a) and (b) that fast shut-in (within 3s and 5s) might also bring a small pressure oscillation shortly after the shut-in. Moreover, the time reaching the temperature recover point is shorter at a shallow well depth than at a deep well depth.

3.4 Other factors impacting the temperature behaviour

The reservoir depth, the abundant pressure of the depleted gas reservoir, the well deviation, injection rates, reservoir properties, among some other factors will all impact the temperature behaviour. Some of the impacting factors have been studied and will be published separately, while the others will be addressed in separate studies to be reported in the future.

4. Conclusions
Flow and thermal behaviour of CO₂ in the injector are numerically investigated. Temperature profiles of CO₂ in well tubing and the impact of water in annulus and surrounding rocks are explored. Moreover, the transient effects of well shut-in on the pressure and temperature profile of CO₂ along the wellbore are predicted.

The increment of CO₂ enthalpy and the potential energy during injection along the tubing and the heat exchange with surrounding formations in the overburden are three factors which lead to an increase of CO₂ temperature in the bottomhole. In this paper, the increment of CO₂ enthalpy and the potential energy during injection are the key factors to heat the CO₂. Besides these three factors, the natural convection of mobile water in the annulus contributes 6.38% of the increase in bottomhole temperature in the specific example studied.

Shutting-in the CO₂ injection can cause the temperature of CO₂ adjacent to wellhead to decrease. In the specific example, the CO₂ temperature adjacent to wellhead goes down to -3°C after the well is shut-in around 5 min. Before 5 min, the shorter the shut-in time, the lower the CO₂ temperature. However, when the time is approaching 5 min, there is little difference in the minimum temperature at the wellhead for different shut-in times. The CO₂ temperature going down during shutting-in is dependent on the CO₂ flow rate and the injection temperature. If the CO₂ flow rate increases, the temperature could be going down more. The implications for such cooling at wellheads should be considered for CO₂ storage projects in offshore depleted gas/oil reservoirs.

Experimental validation of the observations from the numerical studies should be conducted before the numerical results can be used for decision making.

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References


