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# Model for calculating the wellbore temperature and pressure during supercritical carbon dioxide fracturing in a coalbed methane well

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ABSTRACT

Supercritical $CO_2$ fracturing can form a more complex fracture network in rocks than hydraulic fracturing and avoid aqueous phase trapping damage in reservoirs. Thus, it is a promising alternative to hydraulic fracturing for enhancing the production of low-permeability hydrocarbon reservoirs. In this study, a new numerical model for predicting the wellbore temperature and pressure during supercritical $CO_2$ fracturing was established based on thermodynamics, heat transfer, fluid mechanics, and a numerical solution method. In the new model, the physical properties of $CO_2$ are calculated with the Span–Wagner and Vesovic models, and the heat generated by fluid friction losses is absorbed by the tubing and $CO_2$ according to the contact coefficient. The model was used to examine the influences of the injection rate and temperature on the wellbore pressure and temperature. The results indicated that both the heat transfer and pressure in the wellbore are transient processes in the initial stage of injection; as the injection time increases, the heat transfer and pressure in the wellbore can be considered steady processes. The $CO_2$ temperature in the wellbore is considerably affected by both the injection temperature and rate, whereas the wellbore pressure is greatly affected by the injection rate but weakly affected by the injection temperature. The $CO_2$ pressure in the wellbore decreases rapidly as the well depth increases because of high fluid frictional resistance, so a drag reducer suitable for liquid $CO_2$ needs to be developed.

## 1. Introduction

Hydraulic fracturing is an indispensable technology for enhancing the production of low-permeability hydrocarbon reservoirs such as coal and shale gas reservoirs [1,2]. However, hydraulic fracturing requires a large amount of water [3,4], and extraneous water may cause aqueous phase trapping damage in reservoirs [5]. If the reservoir contains clays, water leaking into the matrix during fracturing will cause the clays to swell, which will decrease the absolute permeability. Therefore, some researchers have called for the development of a non-damaging fracturing fluid [6]. Supercritical carbon dioxide (SC-$CO_2$) is a promising fracturing fluid alternative to water because it not only overcomes the disadvantages of water-based fracturing fluids but also captures and stores $CO_2$ [7,8]. $CO_2$ is converted into a supercritical fluid when the temperature and pressure are both higher than their critical values ($T_c$ = 31.1 °C and $P_c$ = 7.38 MPa). The SC-$CO_2$ fluid has many unique physicochemical properties: its density is close to that of a liquid, which helps increase the fluid pressure in the fracture, and its viscosity and diffusivity are close to that of a gas [9], which is beneficial for opening microcracks in the formation. $CO_2$ is expected to replace coalbed methane in reservoirs because of the well-known competitive adsorption effect [10–12]. Moreover, SC-$CO_2$ fracturing can form a more complex fracture network in rocks than hydraulic fracturing [13–15], so $CO_2$ in the downhole should be converted to a supercritical fluid. Accurately predicting the wellbore temperature and pressure of $CO_2$ during SC-$CO_2$ fracturing is a necessary but complex task.

There have been quantitative studies on predicting the temperature in and around a well. The prediction methods are mainly classified into two groups [16]: analytical [17–21] and numerical [9,16,22–25]. Analytical models are easier to solve than numerical models and can calculate the wellbore fluid temperature field under simple working conditions. Analytical models can be used to calculate the temperature field during hydraulic fracturing because the physical properties of water are slightly affected by the temperature and pressure. However, the relationship between the physical properties of $CO_2$ and the temperature and pressure is very complex. Therefore, a numerical method should be adopted to calculate the temperature and pressure fields during the SC-$CO_2$ fracturing process.

At present, numerical models for temperature field calculation are widely used in drilling and fracturing. Raymond [22] was the first to

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**Nomenclature**

| | |
|---|---|
| $c_1$ | Heat capacity of $CO_2$, J/(kg K) |
| $c_2$ | Heat capacity of tubing, J/(kg K) |
| $c_3$ | Heat capacity of fluid in the annulus, J/(kg K) |
| $c_4$ | Heat capacity of casing, J/(kg K) |
| $c_5$ | Heat capacity of cement sheath, J/(kg K) |
| $c_v$ | Volumetric heat capacity, J/(kg K) |
| $G_f$ | Geothermal gradient, K/m |
| $h_1$ | Convection coefficient inside the tubing, W/($m^2$ K) |
| $p_{in}$ | Injection pressure, MPa |
| $P_r$ | Prandtl number, dimensionless |
| $q$ | Volume flow rate of $CO_2$, $m^3$/s |
| $q_{in}$ | Injection rate, $m^3$/s |
| $Q$ | Total friction heat of the unit length tubing, W/m |
| $Q_1$ | Friction heat absorbed by the $CO_2$, W/m |
| $Q_2$ | Friction heat absorbed by the tubing, W/m |
| $r_1$ | Tubing inner radius, m |
| $r_2$ | Tubing outer radius, m |
| $r_3$ | Casing inner radius, m |
| $r_4$ | Casing outer radius, m |
| $r_5$ | Cement sheath outer radius, m |
| $R_c$ | Gas constant, 0.1889 kJ/(kg·K) |
| $Re$ | Reynolds number, dimensionless |
| $T_1$ | Temperature of $CO_2$ inside the tubing, K |
| $T_2$ | Tubing temperature, K |
| $T_3$ | Temperature of fluid in the annulus, K |
| $T_4$ | Casing temperature, K |
| $T_5$ | Cement sheath temperature, K |
| $T_s$ | Surface temperature, K |
| $v_1$ | $CO_2$ flow velocity, m/s |
| $\omega$ | Iteration factor, dimensionless |
| $\rho_1$ | $CO_2$ density, kg/$m^3$ |
| $\rho_2$ | Tubing density, kg/$m^3$ |
| $\rho_3$ | Annulus fluid density, kg/$m^3$ |
| $\rho_4$ | Casing density, kg/$m^3$ |
| $\rho_5$ | Cement sheath density, kg/$m^3$ |
| $\varphi^o$ | Ideal part of the Helmholtz energy, dimensionless |
| $\varphi^r$ | Remaining part of the Helmholtz energy, dimensionless |
| $\mu_0$ | Viscosity at the zero-density limit, Pa s |
| $\lambda_0$ | Thermal conductivity at the zero-density limit, W/(m K) |
| $\lambda_1$ | Thermal conductivity of $CO_2$, W/(m K) |
| $\lambda_2$ | Thermal conductivity of the tubing, W/(m K) |
| $\lambda_3$ | Thermal conductivity of fluid in the annulus, W/(m K) |
| $\lambda_4$ | Thermal conductivity of the casing, W/(m K) |
| $\lambda_5$ | Thermal conductivity of the cement sheath, W/(m K) |

propose a model for calculating the transient and quasi-steady-state temperature distributions during circulation, but this model does not consider the axial heat conduction in the formation. Researchers have used Raymond's model to successively establish temperature field prediction models for different drilling conditions [16,23,24]. However, these models consider the fluid in the wellbore and annulus to be water instead of $CO_2$. There have been few reports on calculating the temperature field for SC-$CO_2$ fracturing. Guo and Zeng [9] established a coupling model for the wellbore transient temperature and pressure during SC-$CO_2$ fracturing. They calculated the $CO_2$ physical parameters with the REFPROP software and investigated the influences of the injection temperature and rate on the wellbore temperature and pressure. However, their model neglects the axial heat conduction in the annulus. In addition, all present models [9,16,24] assume that the heat generated by the fluid friction losses is only absorbed by the fluid. However, it may be more scientifically sound to assign friction heat to the fluid and tubing according to a certain rule.

In this study, our aim was to establish a new numerical model for predicting the wellbore temperature and pressure during SC-$CO_2$ fracturing in a coalbed methane. The proposed model predicts the $CO_2$ physical parameters by using the Span–Wagner and Vesovic models, and the heat generated by fluid friction losses is absorbed by the tubing and $CO_2$ according to the contact coefficient.

## 2. Physical model

The physical model of the SC-$CO_2$ fracturing process is shown in Fig. 1. $CO_2$ enters the tubing through the wellhead at a specified temperature ($T_{in}$). The annular fluid and $CO_2$ in the tubing are separated by the packer, so the fluid in the annulus is stagnant at a specified pressure. Because the fluid pressure during the fracturing process is higher than the $CO_2$ critical pressure, the enthalpy of phase transition can be neglected [9].

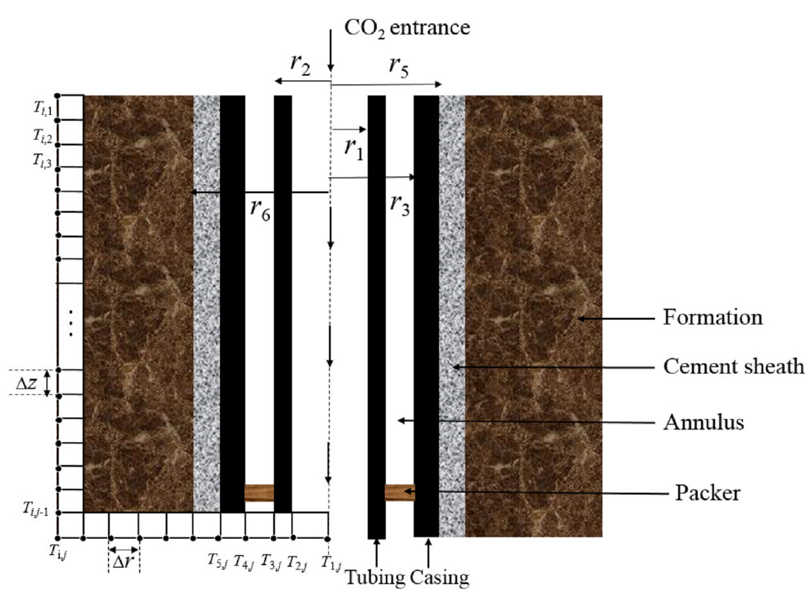


**Fig. 1.** Physical model of the SC-$CO_2$ fracturing process.