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Numerical assessment of the influences of coal permeability and gas pressure inhomogeneous distributions on gas drainage optimization

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A B S T R A C T

In this paper, significant effort was devoted to theoretical/numerical modeling to make an optimal gas drainage design for a pre-drainage coal seam considering the inhomogeneity of coal permeability and gas pressure. A fully coupled model of gas flow, gas diffusion and permeability evolution was developed to evaluate the borehole drainage performances of safety needs (primary consideration) and economic efficiency (secondary consideration). A novel method was applied to rebuilt the non-uniform initial condition in COMSOL to realize the inhomogeneous distribution of coal permeability and gas pressure in the numerical simulations. The significant influences of the inhomogeneity of coal permeability and gas pressure on gas drainage were discussed, and two main disadvantages were visually revealed, including unnecessary engineering cost and enormous mining risk. The optimal gas drainage design consists of three different borehole spacings available for 6 zones, being able to save about 21.5% engineering cost compared to that without considering the reservior inhomogeneity. Numerical simulation results are also helpful to the gas drainage technological innovations.

1. Introduction

Coal mine methane (CMM) is both a potentially valuable energy and a serious hazard in active coal mines, degassing coal seams is an important for mitigating this hazard and results in the beneficial recovery of a cleanburning, low-carbon fuel resource (Karacan et al., 2011). Shanxi province is the most important coal production base of China, and its landform characteristics are very special: the Loess Plateau and its dusty soil cover almost the whole Shanxi province, which has long been suffering from serious soil erosion, resulting in most parts of Shanxi province is gully-hill dominated (Zhao et al., 2013; Shi and Shao, 2000). The gully-hill dominated landform greatly influences the buried depth, generating typically inhomogeneous distributions of gas pressure and coal permeability, and further influences gas drainage.

The drainage performance of boreholes is the main foundation to make gas drainage design, which usually can only be pre-evaluated by numerical simulations based on strict theoretical modeling of the physical mechanism of gas drainage. Reservoir-simulation technology has the capability to provide us with an economical mean to solve complex engineering problems, the successful quantitative evaluations of gas drainage in a coal seam are not only based on the gas migration theory but also based on the valid predictions of gas occurrence distribution and coal permeability distribution.

A significant amount of work has been completed in the area of modeling gas diffusion, gas flow, coal permeability (coupled hydro-mechanical response) and FEM (finite element method) calculation (Wei et al., 2007; Manik et al., 2000).

According to the physical mechanism of gas drainage, the theoretical model should consist of the governing equations of gas flow, gas diffusion and permeability evolution, and the achievements of the coupling relations between the three field governing

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equations. Valliappan and Zhang (1996) presented a coupling mathematical model for gas flow and coal deformation, and the diffusion effect of adsorbed methane has been taken into account. Gilman and Beckie (2000) pointed out that coal-seam methane reservoirs have some unique features compared to conventional gas reservoirs, and proposed a simplified mathematical model of methane migration in a coal seam taking these unique features into account. In consideration that many coals exhibit bi- or multimodal pore structure, Shi and Durucan (2003) developed a bidisperse pore model for gas diffusion in coal matrix. Ye et al. (2014). studied the non-Darcy flow behavior in coal seams by coupling coal permeability change and variable non-Darcy factor in a dual porosity model. Zhu et al. (2011). built a fully coupled model to examine the complex coal-gas interactions under variable temperatures.

Moreover, in general, it is impossible to get a theoretical solution for the fully coupled model of gas flow, gas diffusion and permeability evolution, and numerical simulation is an effective method to the multi-physical phenomena. Based on a quasisteady-state, nonequilibrium diffusion-sorption model, King et al. (1986) developed a numerical model for the simulation of the unsteady-state flow of methane and water through dual-porosity coal seams. Manik et al. (2000). developed a three-dimensional, two-phase, dual porosity, fully implicit, coalbed compositional simulator. Clarkson et al (Clarkson and McGovern, 2005). presented a new coal-bed methane (CBM) prospecting tool by combining single-well reservoir simulators with a gridded reservoir model, Monte Carlo simulation, and economic modules. Thararoop et al. (2012). developed a multi-mechanistic, dual-porosity, dual-permeability, numerical flow model for CBM reservoirs, taking the effects of water presence in the coal matrix into account. Chen et al. (2013) improved an relative permeability model for coal reservoirs, which was then coupled into the reservoir simulation model to study how the coal porosity change induced relative permeability change affects the CBM production. Wei et al. (2007). reviewed three types of existing CBM reservoir models, including conventional black-oil and compositional models, specialized CBM models and improved CBM models. Liu and Cheng (2014) conducted a series of numerical simulations and field tests to study the influences of pressure drop on gas drainage. Yang et al. (2010). studied the dynamic process of pressure relief and gas drainage during coal mining by conducting a series of numerical simulations. Liu et al (Yanwei et al., 2016). studied the influence factors of high-pressure hydraulic flush enhanced gas drainage based on a numerical method.

Though the mechanism and numerical simulator of gas migration in a coal seam have drawn a lot of attention, most of the recently published studies are focused on CBM recovery. To some degree, the physical mechanism of gas drainage is similar to that of CBM extraction. However, the objectives of gas drainage and CBM extraction are different. The main objective of gas drainage (degassing coal seam) is to mitigate coal and gas outburst hazards. Comparing with CBM recovery, quantitative evaluations of gas drainage is more critical as which is closely related to the mining safety. Thus, gas drainage design is mainly based on the borehole drainage performance related to safety needs, instead of economic efficiency (which is the secondary consideration). Moreover, considering the safety needs of coal mines in Shanxi province, the inhomogeneous distributions of gas pressure and coal permeability (induced by the influences of the loess plateau geomorphology) should be taken into account when conducting the numerical simulation, which has seldom been implemented in numerical simulators of gas migration to date. Therefore, further efforts should be made to fill a gap in quantitative evaluations of gas drainage performance while ensuring that the influences of the inhomogeneous distributions of gas pressure and coal permeability are taken into account.

The primary objective of this paper is to make an optimal gas drainage design for a pre-drainage coal seam considering the inhomogeneous distributions of gas pressure and coal permeability. The principal feature of this work is that the influences of the inhomogeneous distributions of gas pressure and coal permeability on gas drainage are investigated through theoretical/numerical modeling. To achieve this goal, a fully coupled model of gas migration in a coal seam was developed; image recognition technology was applied to rebuilt the initial inhomogeneous condition in numerical simulators. By conducting two numerical case studies, disadvantages of drainage design without considering the inhomogeneous distributions of gas pressure and coal permeability and the optimal gas drainage design were analyzed. The numerical simulations are helpful to the gas drainage technological innovations.

2. Mathematical model

In the following, a set of governing equations are deduced which govern the gas diffusion, gas flow, coal deformation and dynamic permeability evolution. These derivations are based on several simplifying assumptions: (1) The coal seam is dry and isothermal, ignoring the influences of water and temperature. (2) The coal seam is an isotropic and dual poroelastic but inhomogeneous medium. (3) Methane behaves as an ideal gas, and its viscosity is constant under isothermal conditions. (4) Coal is saturated by methane.

Besides, to describe the storage state and migration of CMM in a coal seam, we utilize the dual porosity concept (Liu et al., 2015a). That is, the coal seam is typically dual-porosity systems that consist of coal matrix surrounded by intersecting fractures. In such a dual porosity medium, at every point, two pressures are defined: the pressure in fractures, p_f, and the pressure in coal matrix, p_m. Since one can hardly speak about the free gas (and gas pressure) in micropores, p_m is defined as the "virtual" pressure that would be in equilibrium with the current concentration of adsorbate in matrix blocks (Gilman and Beckie, 2000).

2.1. Gas release from the coal matrix

Gas release from the coal matrix is assumed to be driven by the concentration gradient, and the gas exchange rate can be expressed as (Mora and Wattenbarger, 2009; Wang et al., 2012)

$$Q_m = \frac{1}{\tau}\left(c_m - c_f\right) \tag{1}$$

where Q_m is the gas exchange rate per volume of coal matrix blocks, kg/(m^3·s). c_m is the concentration of gas in the matrix blocks, kg/m^3. c_f is the concentration of gas in the fractures, kg/m^3. τ represents the "sorption time", and it is numerically equivalent to the time during which 63.2% of the coal gas content is desorbed (Mora and Wattenbarger, 2009; An et al., 2013; Zuber et al., 1987), s; Moreover, it has a reciprocal relationship with the diffusion coefficient and shape factor $\tau = 1/(D \cdot \sigma_c)$, where D is the gas diffusion coefficient, m^2/s; σ_c is coal matrix block shape factor, m^{-2}.

Based on the assumptions and make use of the ideal gas law:

$$c_m = \frac{M_c}{RT} p_m \tag{2}$$

$$c_f = \frac{M_c}{RT} p_f \tag{3}$$