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Investigation of varying-composition gas injection for coalbed methane recovery enhancement: A simulation-based study

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ABSTRACT

Gas-injection in coalbed methane resources is a well-studied enhanced recovery technique. Through several experimental, simulation and pilot studies, it has been shown that the composition and type of injectant have a significant impact on the ultimate Methane recovery and the production rate. The commonly used gases are Carbon Dioxide (CO_2), Nitrogen (N_2) and a mixture of N_2 and CO_2. Pure CO_2 (CO_2-enriched gas) injection may cause irretrievable well injectivity reduction, because of high adsorption affinity of coal to CO_2, which result in matrix swelling. By injecting pure N_2 (N_2-enriched gas), an early breakthrough of the injected gas may occur, which degrades the quality of the produced gas. Studies have shown that a better performance is obtained, when a mixture of CO_2 and N_2 is injected, and there is an optimum composition for the mixture, which depends on the geomechanical and sorption characteristics of the coal. In all of these studies, the composition of the injected gas is kept constant within the period of injection.

In this study, a varying-composition injection is proposed, as an alternative technique to the constant-composition injection. In a varying-composition injection, the composition of the injected gas is altered during the injection period through several steps. Such a scenario can postpone the breakthrough time, and meanwhile avoid the deterioration of well injectivity. To assess the proposed method and find an optimal and practical injection schedule, a semi-synthetic simulation model is constructed. Different injection scenarios are compared with each other, using a compositional simulator (ECLIPSE-300), which uses the extended Langmuir isotherm and the modified Palmer-Mansoori model. By carrying out a series of sensitivity analyses, an optimum scenario is found. The best obtained scenario is the one that begins by injecting a mixture with less CO_2, and continues by a sequential rise in the CO_2 fraction. The outcomes confirm that the proposed technique has the following benefits, in comparison with the optimum scenario of constant-composition injection: 1- greater Methane recovery, 2- higher Methane production rate 3- deferment in permeability reduction, 4- later N_2 breakthrough.

1. Introduction

The demand for energy is escalating while energy supply from conventional hydrocarbon reservoirs is declining. To fill this gap, developing unconventional reservoirs is inevitable. Coalbed Methane (CBM) reservoirs are one of the fast growing unconventional resources, which usually contain a considerable amount of Methane (CH_4) in an adsorbed state on the surface of micropores. Coal seams are typically naturally fractured rocks for which a dual-porosity model can be used to describe the fluid flow (Shi and Durucan, 2005). Micropores (coal matrix) are the main storage, and cleats (macropores) are the main paths for the flow (Clarkson et al., 2010), which typically, at the initial condition, are saturated with water. In order to produce Methane, cleats should be dewatered. This decreases the overall reservoir pressure, and creates pressure drawdown which leads to desorption of gas from the matrix. The desorbed gas diffuses from the matrix to the cleats (Fick's law) and then flows from the cleats to the wellbore (Darcy's law) (Seidle, 2011). The total Methane recovery by the natural depletion is not expected to exceed 50% of the original gas in place (Puri and Yee, 1990), due to the fact that Methane partial pressure in

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cleats cannot reach zero.

To accelerate Methane production and enhance recovery, two pressure gradients should be kept at maximum simultaneously: Methane partial pressure gradient between cleats and matrix and pressure gradient between cleats and wellbore. This is not obtainable in the natural depletion. Thus, in the early 90s, the injection of a foreign gas into the coal seams was proposed as an enhanced coalbed methane (ECBM) recovery method. Gas injection in coal seams can.

i expedite the desorption and diffusion process by sweeping Methane in the cleat system and dropping Methane partial pressure (almost zero), while
ii improve productivity and injectivity by maintaining reservoir pressure which keeps the cleats open and also creates the drive for the convection flow in the cleats.

The performance of gas injection is controlled by several elements including, the type of injected gas, coal sorption characteristics, geomechanical and petrophysical properties. The commonly used gases are Carbon Dioxide (CO_2) and Nitrogen (N_2). Fulton et al. (1980) proposed CO_2-ECBM, and carried out many laboratory analyses using samples of the Appalachian basin coal. They discovered that the recovery factor can increase 30% by CO_2 injection compared to the natural depletion. A simulation study by Sinayuç and Gümrah (2009) was performed based on the reservoir data of Zonguldak coal basin. An increment of 23% CH_4 production was observed by injecting CO_2. The first field application of CO_2-ECBM injection was piloted in the Burlington's Allison unit. CO_2 was injected for six months, and the results showed an increase in Methane production (Stevens et al., 1998). An additional benefit of the CO_2-ECBM is the carbon sequestration (Wong et al., 2000).

One technical problem with CO_2 injection is matrix swelling. As the matrix is swollen, the cleat openings decrease (Durucan et al., 2009; Durucan and Shi, 2009). A numerical study showed that the permeability might lessen by two orders of magnitude (Durucan and Shi, 2009). Reduction in permeability leads to the deterioration of well injectivity. Mazzotti et al. (2009) conducted an experimental study on the coal matrix swelling effect for different types of gases, and the changes of coal volume after being exposed to different gases (CO_2, N_2, CH_4 and He) were measured. The result showed that the coal was swollen more severely by CO_2 in comparison with the other gasses (Mazotti et al., 2009). This is mainly due to the fact that coal has a greater affinity towards CO_2 (Fulton et al., 1980; Moore, 2012; Fang et al., 2013). The higher CO_2 affinity can be explained by the geometrical, electrical and physical/chemical properties of gas molecules and also the functional groups on the coal surface (Cui et al., 2004; Larsen, 2004). For instance, CO_2 molecules are smaller than CH_4 molecules and also have a linear shape. These geometrical features facilitate CO_2 entrance to more restricted pore spaces and dislocate competitively pre-adsorbed CH_4 molecules out of micropore surfaces (Cui et al., 2004). Also, CO_2 has a more favorable interaction enthalpy than hydrocarbons (e.g., Methane). This favorable interaction increases CO_2 solubility in coals compared to Methane which may increase the CO_2 diffusivity and sorption capacity (Larsen, 2004).

Experimental, simulation and field studies determined that a greater production rate can be achieved by N_2 injection compared to CO_2 injection, which is mostly on the account of low sorption affinity of coal to N_2. Reeves and Oudinot (2004) provided a report about the Tiffany unit N_2-ECBM pilot. One distinctive feature regarding N_2 injection was the rapid and dramatic response of Methane production (Perera et al., 2015). It was found that the Methane rate increased by a factor of five. However, an early Nitrogen breakthrough was observed (Reeves and Oudinot, 2004). The rapid increment of Methane production is due to the enhancement of well injectivity and cleat permeability (Shi et al., 2008). Small adsorbility of N_2 on the coal induces matrix shrinkage. N_2 stimulates the desorption process by sweeping Methane from the cleats, but, because of the small cleats volume, the N_2 travels quickly towards the producers, which results in an early breakthrough. The experimental study conducted by Zhou et al. (2013b) confirmed the early breakthrough problem.

A better result can be obtained by injecting a mixture of different gases. Shi and Durucan (2005) carried out a micropilot study in the Fenn Big Valley to develop a new permeability model to account for both swelling and shrinkage associated with mixed gas injection. They concluded that by injecting flue gas, better results can be obtained. Durucan and Shi (2009) came out with a simulation analysis of mixed gas injection in coalbeds. The aim of the study was to investigate the overall performances of different N_2/CO_2 mixtures on production gas rate and quality. Based on the results it was observed that Methane production rate increases significantly, with N_2 enriched gas mixture. Although, by injecting such a mixture, cumulative CH_4 will be greater, the quality of the produced gas is of concern, due to quick N_2 breakthrough. They concluded that injecting a fixed mixture of 13% CO_2/87% N_2 through a continuous injection would result in the highest CH_4 recovery.

The objective of this study is to find an optimal gas injection scenario with varying CO_2 fraction throughout continuous injection of N_2/CO_2 mixture for coalbed methane recovery enhancement. It is a simulation-based study. In the methodology section, the modeling and equations used are explained. In the results and discussion section, the outcomes of the proposed method are presented and compared to the results obtained by natural depletion and continuous injection. In the last section, some conclusive remarks are given.

2. Methodology

Coalbeds are naturally fractured rocks in which coal matrix is enclosed by two sets of perpendicular fractures, face cleats (continuous fractures) and butt cleats (the discontinuous fractures) (Seidle, 2011; Keshavarz et al., 2015In this study, to simulate the flow in such a medium, a dual-porosity model (Huy et al., 2010; Cui and Bustin, 2005) is used, which is an adjusted form of Warren and Root model (1963). In the model, the following assumptions are made: matrix's permeability is zero, gas in the matrix is in adsorbed state (i.e., there is no free gas) and the gas-in-place is defined by concentration (instead of, saturation and pressure), matrix acts as a sink/source term for cleats, the flow between matrix and cleats is govern by diffusion, water exists only in cleats, the flow in cleats can be modeled by Darcy's law, and there is no interconnection between matrixes.

The gas content of component i (V_i) on coal matrix, in equilibrium condition, is a function of partial pressure of that component in cleats (p_i=$y_i p$), total pressure and sorption characteristics of coal. y_i is mole fraction in gas phase, and p is total gas pressure. Extended Langmuir isotherm, Equation (1), is used to represent the multicomponent sorption characteristics of coalbeds (Zhou et al., 2013b).

$$V_i = V_{Li}\frac{\frac{py_i}{P_{Li}}}{1+\sum_{j=1}^{N_c}\frac{py_j}{P_{Lj}}} \tag{1}$$

P_{Li} is the Langmuir pressure constant for component i, V_{Li} is the Langmuir volume constant for component i, and N_c is the total number of components. Coal has different affinities to different components, and this can be described using Langmuir terms.

The flow between matrix and cleats (q_{mci}) is described by Fick's