Modelling and optimization of enhanced coalbed methane recovery using CO2/N2 mixtures

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\textbf{Abstract}
Injection of gas mixtures (CO\textsubscript{2}, N\textsubscript{2}) into coal seams is an efficient method to both reduce CO\textsubscript{2} emissions and increase the recovery of coalbed methane. This process involves a series of complex interactions between ternary gases (CH\textsubscript{4}, CO\textsubscript{2}, and N\textsubscript{2}) co-adsorption on coals, mass transport of two-phase flow, together with heat transfer and coal deformation. We develop an improved thermo-hydro-mechanical (THM) model coupling these responses for gas mixture enhanced CBM recovery (GM-ECBM). The model is first validated, and then applied to simulate and explore the evolution of key parameters during GM-ECBM recovery. Schedules of constant- and variable-composition injection are optimized to maximize CH\textsubscript{4} recovery and CO\textsubscript{2} sequestration. Result shows that the injected gas mixture displaces CH\textsubscript{4} through competitive sorption and accelerates the transport of CH\textsubscript{4} within the coal seam. The consistency between the modelling and field results verifies the feasibility and fidelity of the THM model for effective simulation key processes in GM-ECBM. Permeability evolution is strongly influenced by the combined effects of CH\textsubscript{4} desorption induced matrix shrinkage, CO\textsubscript{2}/N\textsubscript{2} adsorption induced matrix swelling, thermal strains, and compaction induced by changes in effective stress. During ECBM, reservoir permeability first increases due to pressure depletion and CH\textsubscript{4} desorption, then dramatically decreases due to matrix swelling activated by the arrival of the CO\textsubscript{2}/N\textsubscript{2} mixture. CH\textsubscript{4} pressure decreases rapidly at early time due to displacement by the injected gas mixture, and then decreases slowly in the later stage. The sweep of N\textsubscript{2} accelerates CH\textsubscript{4} desorption and subsequent transport, and hence promotes a decrease in reservoir temperatures distant from the injection well even prior to the arrival of CO\textsubscript{2}. CH\textsubscript{4} production rate during GM-ECBM exhibits a decline-increase-decline trend and usually has an elevated but delayed CH\textsubscript{4} production peak compared to primary recovery. A higher CO\textsubscript{2} Langmuir strain constant reduces the critical CO\textsubscript{2} composition in the injected mixture when reaching the threshold of well shut down. An improved balance between early threshold (N\textsubscript{2}) and large matrix swelling (CO\textsubscript{2}) can be achieved by injection beginning with low CO\textsubscript{2} composition and following with a sequential increase of CO\textsubscript{2} composition. In studied cases, the gas recovery ratio of the optimal variable-composition case reaches 68.4% compared to of 59.4% pure CO\textsubscript{2} and 64.2% of optimal constant-composition cases, indicating a higher efficiency of variable-composition injection.

1. Introduction

Coalbed methane (CBM) recovered from unconventional reservoirs is an important source of energy that accounts for approximately 6–9% of the current natural gas production [1–3]. CBM is also recovered to improve safety during coal mining and in particular to prevent gas explosions, coal and gas outbursts [4–6]. In both cases, CBM is recovered by boreholes to the surface [7]. However, the methane recovery rate driven by natural pressure depletion reduces rapidly due to the sharp decrease of reservoir pressure around the wellbore [3,8]. Co-injection of other gases into the coal seam is an efficient approach to increase CBM recovery through competitive adsorption and in maintaining reservoir pressure to prevent the closure of coal fractures [9,10]. Gases commonly used as injectants are nitrogen (N\textsubscript{2}), carbon...
Gas-mixture enhanced coalbed methane recovery (GM-ECBM) involves interactions among the ternary gases (CH₄, CO₂, and N₂), co-adsorption, gas diffusion in the matrix, gas-water two-phase flow in fractures, heat transfer, and coal deformation [29–32]. These complex processes render field and laboratory tests essentially non-repeatable [33,34]. Numerical simulations may be applied to yield scientific insight into the processes controlling gas injection ECBM recovery [35–37]. The simulation of gas injection in coals beds was first carried out to investigate overall performance during injection [38]. The feasibility of CO₂-ECBM recovery has been investigated by combining the essential features of infiltration and diffusion of binary gases (CO₂, CH₄), competitive sorption and deformation [39] and in examining the impacts of N₂ injection, [40] pre-drainage of formation water and non-isothermal adsorption for the evaluation of gas production [41–43]. In recent studies, these two factors were taken into consideration in simulations [44,45]. In general, these studies provide a useful theoretical foundation for gas injection enhanced CBM recovery, although some important factors are still overlooked, as shown in Table 1. Therefore, a fully coupled model for GM-ECBM has some utility in defining the full suite of interactions.

Due to the low sorption capacity and low dynamic viscosity of N₂, rapid and dramatic response of CH₄ production has been observed in N₂-ECBM pilots [47]. However, early N₂ breakthrough may also result, which may require early well shutdown due to contamination by N₂ of produced gas. This early N₂ breakthrough has been confirmed by several experiments, simulations and field tests [19,24,25,27]. Hence, the composition of the injected gas mixture (N₂, CO₂) has a significant impact on ultimate CH₄ recovery. An optimal composition for the N₂/CO₂ mixture injection may be found to balance early N₂ breakthrough and excessive matrix swelling induced by CO₂ adsorption, and prolong the process of economic CH₄ recovery together with CO₂ sequestration in coal.

The following describes an improved thermo-hydro-mechanical (THM) coupling model for simulating GM-ECBM recovery, including the interactions of ternary gases non-isothermal co-adsorption, mass transport by diffusion in matrix and two-phase flow in fractures, and thermal transfer, as well as the coupling of these fields with the evolution of porosity and permeability. This model is firstly validated by history matching in situ observation. Then, the evolutions of key parameters during GM-ECBM recovery are explored. Finally, the recovery schedules of constant- and variable-composition are optimized to determine the optimal composition for gas mixture injection.

### Table 1

<table>
<thead>
<tr>
<th>Considered by</th>
<th>Key factors</th>
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<tbody>
<tr>
<td>Coal deformation</td>
<td>Two phase flow</td>
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<tr>
<td>Durucan and Shi (2009) [24]</td>
<td>√</td>
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<tr>
<td>Zhu et al. (2011) [41]</td>
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<tr>
<td>Wu et al. (2011) [39]</td>
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<td>Sun et al. (2016) [37]</td>
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<td>Sayyafzadeh et al. (2016) [46]</td>
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<td>Ren et al. (2017) [40]</td>
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<td>Ma et al. (2017) [44]</td>
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<td>Teng et al. (2018) [43]</td>
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<td>Fan et al. (2018) [45]</td>
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Note: check mark identify that the process is considered in the developed model.
in the opposite sequence – this gas mixture first flows from the injection well to the fractures, then diffuses from the fractures to the matrix, followed by the competitive adsorption with CH4 present on pore surfaces.

The mass transport process of gas and water mixture during GM-ECBM recovery is shown in Fig. 1. According to the aforementioned assumptions, the production and injection behaviors of GM-ECBM recovery are controlled by the coupling responses among hydraulic, thermal and mechanical fields (Fig. 2). The hydraulic field relates to the competitive non-isothermal adsorption of ternary gases (CO2, N2 and CH4) in the coal matrix, gas diffusion between matrix and fractures, and the mass transport of the mixture by gas-water two-phase flow in the fractures. Competitive adsorption, gas diffusion and two-phase flow are affected not only by the corresponding partial gas pressure within the hydraulic field, but also by the thermal and mechanical fields – due to changes in porosity and permeability resulting from the varying of temperature and effective stress. In coal seams saturated with formation water, gas migration in the fractures is hindered by the low gas relative permeability, especially during the initial dewatering stage when the water saturation is relatively high. The thermal field includes heat transfer among the solid-liquid-gas phases and the energy changes induced by gas ad/desorption and coal deformation. The fluid composition and the flow rate of ternary gases and water mixture will affect the heat conduction/convection of the entire coal seam, as well as the heat transfer efficiency.

In addition, change in effective stress induced by CH4 depletion and CO2/N2 injection will change the reservoir permeability, and then change the rate of heat transfer. The coal seam is characterized as a poroelastic medium with single-permeability and dual-porosity which contains both fractures and matrix pores. Gas and water are transported within the pores and fractures and in turn alter the coal deformation. Meanwhile, the thermal stress induced by changes in temperature also acts on coal skeleton to drive deformation. The following establishes a THM model for GM-ECBM recovery that considers the prior bidirectional interactions between coal deformation, heat transfer, and ternary gas mixtures and water migration.

![Fig. 1. Mass (CH4, CO2, N2 and water) transport during GM-ECBM recovery (modified after Shi et al. (2008) [11]).](image1)

![Fig. 2. Coupling relationships of the THM model for gas mixture enhanced CBM recovery.](image2)
Porosity and permeability are key factors influencing the flow of gas and water within coal seams (relations (8), (10), (14), and (16) in Fig. 2), which directly affects predictions of the evaluation of gas production and injection during GM-ECBM recovery. As shown in Fig. 3, the coal seam can be considered as a dual-porosity and single-permeability absorbing medium, which consists of fractures and coal matrix with interior pores [48,50]. Permeability is linked to fracture porosity according to the cubic law. Since fracture aperture is sensitive to the state stress and the mechanical properties of the coal seam, the permeability is concomitantly sensitive to effective stress and gas ad/desorption induced swelling/shrinkage that accompanies the process of gas production and injection.

By considering CH4 desorption induced matrix shrinkage, CO2 and N2 adsorption induced matrix swelling and thermally induced coal deformation, the porosity model of matrix pores can be defined as [7]:

\[
\phi_m = \phi_{m0} + \frac{(\sigma_m - \sigma_{m0})}{(1+\varepsilon_v)}
\]

where \(\varepsilon_v = e_v + p_m/K_K\alpha_T\varepsilon_m\); \(e_v\) is the volume strain in the coal; \(\sigma_{m0} = 1 - K/K_r\) is the Biot effective stress coefficient for the coal matrix; \(K = D/(1-2v)\) is the bulk modulus, GPA; \(K_r = L/v(1-2v)\) is the skeleton bulk modulus, GPA; \(D = 1/(1/E + 1/(L/\kappa_m))\) is the effective elastic modulus, GPA; \(E\) is elastic modulus, GPA; \(\kappa_m\) is the normal stiffness of the fracture, Pa/m; \(E_s\) is the skeleton elastic modulus, GPA; \(v\) is Poisson ratio; \(p_m\) is the gas mixture pressure in matrix, MPa; \(\alpha_T\) is thermal expansion coefficient, \(1/K\); \(T\) is temperature, K; \(T_0\) is initial temperature, K; \(\varepsilon_m\) is volumetric strain of the matrix swelling/shrinkage induced by gas ad/desorption; and the subscript ‘0’ represents the initial value of the parameter.

The ad/desorption of the ternary gases mixture on the coal matrix usually causes strain swelling/shrinkage. The volume strain induced by gas mixture sorption is the sum of strain induced by each gas component. The extended Langmuir-type equation is used with the gas sorption induced strain [39,45]:

\[
\varepsilon_i = \sum_{i=1}^{3} \varepsilon_{i0} (1 + \beta_i P_{mgi} + \beta_{i2} P_{mgi}^2 + \beta_{i3} P_{mgi}^3)
\]

where \(\varepsilon_{i0}\) is the Langmuir-type strain coefficient of component \(i\), which represents the maximum swelling capacity; \(P_{mgi}\) is the Langmuir-type pressure coefficient of component \(i\), Pa; \(\beta_{i1} = 1/P_{mgi}\) is the gas pressure in the matrix pore of component \(i\) and the subscript ‘i’ denotes the gas component (\(i = 1\) for CH4, \(i = 2\) for CO2 and \(i = 3\) for N2).

The coal seam is a dual-porosity medium which contains both coal matrix and fractures (Fig. 3). The effective stress for the coal matrix and fracture can be defined as [51,52]:

\[
\begin{align*}
\sigma_{m} &= \sigma - (\sigma_m P_{mgi} + \alpha_T P_f) \\
\sigma_f &= \sigma - \alpha_T P_f \\
\end{align*}
\]

where \(\sigma = (\sigma_1 + \sigma_2 + \sigma_3)/3\) is the average principal stress, Pa; \(\alpha_T = 1 - K/(K_m K_0)\) is the Biot coefficient for the fractures; \(P_f = s_f P_{gw} + s_w P_{gw}\) is the fluid pressure in the fracture, Pa; \(P_{gw}\) is the gas pressure in the fracture, Pa; \(P_{gw} = P_{gw} + P_{cap}\) is the water pressure in the fracture, Pa; \(P_{cap}\) is the capillary pressure, Pa; \(s_f\) is the water saturation in the fracture; and \(s_w = 1 - s_f\) is gas saturation in the fracture.

The volumetric strain of the REV can be expressed as [50]:

\[
\Delta_\varepsilon_v = \frac{L_f^3}{L_m^3 K_m} \Delta_\varepsilon_{m0} + \frac{L_f^3}{L_m^3 K_f} \Delta_\varepsilon_f - \frac{L_f^3}{L_m^3} \Delta_\varepsilon_f - \frac{L_f^3}{L_m^3} \alpha_T \Delta T
\]

where \(L_f = L_m + L_f\) is the total width of the representative elementary volume (REV), m; and \(K_m\) is the bulk modulus of the matrix, Pa.

Substituting Eq. (3) into Eq. (4), we can obtain:

\[
\Delta_\varepsilon_v = \frac{L_f^3}{L_m^3 K_m} \Delta_\varepsilon_{m0} + \frac{L_f^3}{L_m^3 K_f} \Delta_\varepsilon_f - \frac{L_f^3}{L_m^3} \Delta_\varepsilon_f - \frac{L_f^3}{L_m^3} \alpha_T \Delta T
\]

The ratio of \(r_{mf} = L_m/L_f\) is defined as the proportion of matrix width to the REV width. Rewriting Eq. (5), the effective stress of the fracture is expressed as:

\[
\sigma_f = \sigma - \alpha_T P_f
\]

\[
= \frac{K_m K_f}{K_f r_{mf}^3 + K_m - K_m r_{mf}^3} \left( r_{mf}^3 \Delta_\varepsilon_m + r_{mf}^3 \alpha_T \Delta T + \Delta_\varepsilon_v + r_{mf}^3 \alpha_m \Delta P_m \right)
\]

The evolution of fracture porosity is dependent on the change in effective stress-induced fracture deformation:

\[
\phi_f = \frac{\phi_{f0} (1 + \Delta T f/L_f)}{\phi_{f0} + \beta_f K_m (3(K_f + K_m r_{mf}^3 - K_m)/K_m) \left( \Delta_\varepsilon_v + \alpha_T \Delta T + \Delta_\varepsilon_v + \alpha_m \Delta P_m \right) K_m}
\]

where \(\phi_{f0}\) is the initial fracture porosity.

Substituting Eq. (6) into Eq. (7), the fracture porosity can be obtained:

\[
\phi_f = \frac{\phi_{f0} K_m}{3(K_f + K_m r_{mf}^3 - K_m)/K_m} \left( \Delta_\varepsilon_v + \alpha_T \Delta T + \Delta_\varepsilon_v + \alpha_m \Delta P_m \right) K_m
\]

The cubic law is applied to define a relationship between fracture porosity and permeability.
where \( k_0 \) is the initial permeability of the fracture, m\(^2\).

2.2. Governing equations for hydraulic field

2.2.1. Ternary gases transport in matrix

According to Dalton’s law, the pressure of a ternary mixture of nonreactive gases in matrix pores and coal fractures can be defined as [13]:

\[
\begin{align*}
\rho_{fb} &= \rho_{fmg} + \rho_{fgi} + \rho_{fmi} \\
\rho_{fb} &= \rho_{gmg} + \rho_{gmi} + \rho_{ghi} \\
\rho_{fmg} &= \rho_{ghi} + \rho_{fmi} + \rho_{fgi}
\end{align*}
\]

where \( \rho_{fmg}, \rho_{fgi}, \) and \( \rho_{fmi} \) are the gas pressure in the matrix pores for CH\(_4\), CO\(_2\), and N\(_2\), respectively; and \( \rho_{gmg}, \rho_{gmi}, \) and \( \rho_{ghi} \) are the gas pressure in the coal fractures for CH\(_4\), CO\(_2\), and N\(_2\), respectively.

The ideal gas law gives the relationship between gas pressure and density for the free ternary gases, for each component:

\[
\rho = \frac{p}{RT}
\]

where

\[
\begin{align*}
T_{ref} &= \frac{RT_{ref}}{R} \\
\alpha &= \sqrt[3]{\frac{R}{p_f R_c}} \\
\beta &= \sqrt[3]{\frac{R}{p_g R_c}} \\
\gamma &= \sqrt[3]{\frac{R}{p_m R_c}}
\end{align*}
\]

2.2.2. Ternary gases transport in fracture

In the coal reservoir, the pre-existing CH\(_4\) and water and injected CO\(_2\) and N\(_2\) coexist and migrate within fractures. For gas migration in the fractures, CH\(_4\) desorption from the matrix provides a mass source, while the adsorption of CO\(_2\) and N\(_2\) in matrix acts as a mass sink. The gas and water mixture transported as a two-phase flow, and mass conservation for gas migration in the fractures, is defined as [44,49]:

\[
\frac{\partial (s_i \rho_{fbi})}{\partial t} + V_i (\rho_{fbi} \mathbf{q}_{fbi}) = \frac{1}{\tau} \frac{M_{fbi}}{\tau} (p_{fbi} - p_{gbi})
\]

where \( s_i \) is the gas saturation in the fracture; \( \rho_{fbi} \) is the density of gas component \( i, \) kg/m\(^3\); and \( \mathbf{q}_{fbi} \) is the velocity of gas component \( i, \) m/s.

By considering the Klinkenberg effect within the porous medium and gas-water two-phase flow, the velocity of gas flow in the fracture can be defined by the Darcy’s law as [7]:

\[
\mathbf{q}_{fbi} = -\frac{k}{\mu_{fbi}} \frac{1 + b_1 \rho_{fbi}}{\rho_{fbi}} \nabla p_{fbi}
\]

where \( k \) is the absolute permeability of the coal seam, which is defined by Eq. (9), m\(^2\); \( k_R \) is the gas relative permeability; \( \mu_{fbi} \) is the dynamic viscosity of gas component \( i, \) Pas; and \( b_1 \) is the Klinkenberg factor, Pa.

The relative permeability curves in the porous medium are often expressed with the Corey functions [54]. The relative permeabilities for gas and water phases are defined as [55]:

\[
\begin{align*}
\kappa_{gbi} &= k_{gbi} (1 - s_i)^{n_1} (1 - 0.5 s_i)^{1 + n_2} \\
\kappa_{wbi} &= k_{wbi} (s_i + 0.5 s_i)^{n_1 + 1 + n_2}
\end{align*}
\]

where

\[
\begin{align*}
k_{wbi} &= k_{wbi} (s_i + 0.5 s_i)^{n_1 + 1 + n_2} \\
k_{gbi} &= k_{gbi} (1 - s_i)^{n_1} (1 - 0.5 s_i)^{1 + n_2}
\end{align*}
\]

where \( k_{wbi} \) is the endpoint relative permeability of water; \( \kappa_{wbi} \) is the endpoint relative permeability of gas; \( \lambda \) is the cation size distribution index; \( n_1 \) is the tortuosity coefficient for the relative permeability; and \( s_i \) is the effective water saturation, defined as [7,56]:

\[
s_i = \frac{s_i - s_{rew}}{1 - s_{rew} - s_{g}}
\]

where \( s_{rew} \) is the irreducible water saturation; \( s_{g} \) is the residual gas saturation. The capillary pressure is also related to the effective saturation [55]:

\[
p_{gwbi} = p_c (s_i)^{-1/4}
\]

where \( p_c \) is the entry pressure, Pa.

Substituting Eqs. (19) and (20) into Eq. (18), the governing equations for transport of the ternary gas mixture in the fractures can be obtained as:
2.2.3. Water transport in fracture

Absent a source term, the coal reservoir gradually dewaters with the progress of gas injection and production. For two-phase flow and mass conservation, the equation for water transport in the fractures is defined as [49]:

\[
\frac{\partial}{\partial t}(s_w \phi_w \rho_w) + V \cdot \left( - \frac{k_{eff} \phi_w}{\mu_w} (1 - s_w) \nabla \rho_w \right) = 0
\]

(24)

where \( s_w \) is the water saturation; \( \rho_w \) is the water pressure in the fractures, Pa; \( \mu_w \) is water density, kg/m³.

Also, the velocity of water can be expressed by the Darcy’s law as:

\[
\bar{u}_w = -\frac{k_{eff}}{\mu_w} \nabla \rho_w
\]

(25)

where \( k_{eff} \) is the relative permeability; and \( \mu_w \) is the dynamic viscosity of water, Pa.s.

By substituting Eqs. (20) and (25) into Eq. (24), we obtain the governing equation of water transport in the fractures as:

\[
\frac{\partial}{\partial t}(s_w \phi_w \rho_w) + V \cdot \left( - \frac{k_{eff}}{\mu_w} (1 + \frac{2}{3} \nabla V) \rho_w \right) = 0
\]

(26)

2.3. Governing equations for coal deformation

The deformation induced by the pressure of fluid mixture in both matrix and fractures (effective stress), together with shrinkage/swelling induced by gas sorption/desorption and thermal effects defines the total strain as [39,40,43]:

\[
\varepsilon_{ij} = \frac{1}{2G} \sigma_{ij} - \left( \frac{1}{6G} - \frac{1}{9K} \right) \varepsilon_{ii} \delta_{ij} + \frac{\alpha_m P_m + \alpha_i P_i + \alpha_t T + \alpha_j \varepsilon_{ii} + \alpha_{ij} \delta_{ij}}{3} \]

(27)

where \( G = D/(1 + \nu) \) is the bulk modulus, Pa; \( \nu \) is Poisson ratio; \( D = 1/[E(1 + (\nu/K))] \) is the effective elastic modulus, Pa; \( K \) is the normal stiffness of the fracture, Pa/m; \( E \) is the elastic modulus, Pa; \( K = D/(1 − 2\nu) \) is bulk modulus, Pa; and \( \delta_{ii} \) is the Kronecker delta with 1 for \( i = k = 0 \) and 0 for \( k \neq i \).

The strain-displacement relation (the Cauchy formula) and stress equilibrium relations can be expressed as [7]:

\[
\left\{ \begin{array}{l}
\varepsilon_{ii} = \frac{1}{2} (u_{i,i} + u_{i,i}) \\
\varepsilon_{ij,i} + f_{ij} = 0
\end{array} \right.
\]

(28)

where \( u_{i,i} \) is the deformation in the \( k \) direction, \( m; f_k \) is the body force in the \( k \) direction, \( N; k; l = x, y, z \).

Substituting Eq. (28) into Eq. (27), the governing equation for mechanical field can be obtained:

\[
\begin{align*}
G u_{ik,k} + \frac{G}{1 - 2\nu} u_{ik,k} & - (\alpha_m P_{mk,k} + \alpha_i P_{ik,k}) - K \varepsilon_{ii} T_{i,k} \\
- K \sum_{i=1}^{3} \left( \frac{\varepsilon_{ii} \delta_{iiP_{mk}}}{1 + \sum_{l=1}^{3} \delta_{ilP_{mk}}} \right) + f_k & = 0
\end{align*}
\]

(29)

2.4. Governing equations for heat transfer

The coal skeleton, ternary gas mixture and water are contained within a single representative elementary volume (REV). When the gas mixture is injected into the coal seam, heat transfer occurs due to the variation in internal energy caused by temperature change, strain energy by coal deformation, isosteric heat by gas de/adsorption, as well as the heat convection and conduction among the solid-gas-water phases. The thermal equilibrium within the REV is may be expressed as [7,41,45]:

\[
\frac{\partial}{\partial t} \left( \rho C_p \lambda_{eff} T \right) + \eta_{eff} \nabla V T - \nabla \cdot \left( \lambda_{eff} \nabla T \right) + K \varepsilon_{ii} T_{i,k} + \frac{1}{2} \sum_{i=1}^{3} \eta_{m} \rho C_{pm} \frac{\partial V}{M_{pm}} = 0
\]

(30)

where \( (\rho C_p)_{eff} \) is the effective specific heat capacity of coal mass, J/(m³ K); \( \eta_{eff} \) is the effective heat convection coefficient of the fluid mixture, J/(m²·s); \( \lambda_{eff} \) is the effective thermal conductivity, W/(m·K); \( \eta_{m} \) is the isosteric heat of gas adsorption of component \( i \), kJ/mol. In Eq. (30), the terms from left to right represent, respectively, the change of internal energy, heat convection, heat conduction, strain energy of the coal skeleton and gas de/adsorption heat.

The effective specific heat capacity is determined by the density and the specific heat capacity of all components within the coal mass:

\[
(\rho C_p)_{eff} = (1 - \phi_f - \phi_m)C_i + \sum_{i=1}^{3} (s_i \phi_f \rho_m + \phi_m \rho_m) C_m + s_w \phi_f \rho_w C_w
\]

(31)

where \( C_i, C_m \) and \( C_w \) are the specific heat capacities of the coal skeleton, ternary gas mixture (CH₄, CO₂, and N₂) and water, respectively, J/(kJ·K).

The effective heat convection coefficient of the coal mass is related to the convective heat transfer of the gas and water mixture in the fracture:

\[
\eta_{eff} = \sum_{i=1}^{3} \rho_{m} C_{pm} \frac{k_{eff}}{\mu_{pm}} \left( 1 + \frac{\mu_{pm}}{\mu_w} \right) \frac{\partial V}{M_{pm}} - \frac{\rho_{m} C_{pm} k_{eff}}{\mu_{pm}} \frac{\partial V}{M_{pm}}
\]

(32)

The effective thermal conductivity of the coal mass is a linear combination of the thermal conductivity of each component:

\[
\lambda_{eff} = (1 - \phi_f - \phi_m) \lambda_i + \phi_m \lambda_m + \phi_f (s_i \lambda_{gi} + s_w \lambda_{gw})
\]

(33)

where \( \lambda_i, \lambda_m, \lambda_{gi}, \lambda_{gw} \) are the thermal conduction coefficients for the coal skeleton, gas mixture in the matrix, gas mixture in the fracture, and water in the fracture, respectively, W/(m·K).

We assemble the governing equations representing the different fields (Eqs. (17), (23), (26), (29) and (30)), together with the coupling terms of Eqs. (1), (8) and (9), to establish the fully coupled thermo-hydro-mechanical model for GM-ECBM recovery.
sorption is considered instead of ternary (CH4, CO2, and N2) co-ad-

cophlished THM model Eq.(34) by neglecting the roles of

2.5. Simplified form PDE interfaces to obtain numerical solution.

This model comprises a series of partial differential equations (PDEs), which can be implemented into COMSOL multiphysics software together with the thermal between the matrix and fractures and two-phase

comprises the governing equations of coal deformation, mass transfer

3. Numerical modelling of gas mixture injection enhanced CBM recovery

The established THM model is first validated against primary CBM recovery in situ, and then applied to simulate the process of GM-ECBM recovery. The evolutions of significant parameters including gas pressure, gas content, reservoir temperature, permeability, CH4 production, CO2 and N2 storage are comprehensively analyzed.

3.1. Reservoir conditions and numerical model

3.1.1. Objective and model geometry

The Fanzhuang area represents a typical block for CBM development in Qinshui Basin – one of the earliest developed and most commercially valuable basins in China. Coal seam #3 is characterized by uniform thickness, high gas content and shallow burial depth and is considered as the primary target for CBM recovery from the Shanxi formation [57]. The pressure depletion method is generally adopted for coaled methane recovery [37]. However, with the decrease of reservoir pressure, gas production rate decreases rapidly, motivating the numerical investigation of gas injection enhanced CBM recovery to maximize both methane recovery and CO2 sequestration.

Two sets of simulations are performed in this section: (i) the first is to validate the established THM model through history matching with in situ observations of natural pressure depletion in an unstimulated production well; (ii) the second is to apply the validated model to simulate the process of GM-ECBM recovery, together with the evolution of key parameters.

Well spacing varies from 334.67 m to 537.98 m, with shallow vertical CBM wells usually arranged on a rectangle pattern of 300 m × 300 m–500 m × 500 m [7]. Here, an intermediate well pattern of 400 m × 400 m is adopted, as shown in Fig. 4. The production well is located at the center of domain surrounding by four injection wells. Because of the repeating symmetry of the geometric model, we use a quadrant located in the upper right corner of the geometry for the numerical simulation. For GM-ECBM recovery, a production well and an injection well are designed at the lower left corner and the upper right corner of this 2D geometry. While for primary CBM recovery, only a production well is set to the lower left corner. The section A-B and point P1 in the 2D geometry are set to measure the variation of reservoir parameters.

The simplified THM model for primary CBM recovery, Eq. (35), also comprises the governing equations of coal deformation, mass transfer between the matrix and fractures and two-phase flow in the fracture, together with the thermal field. However, only single gas (CH4) adsorption is considered instead of ternary (CH4, CO2, and N2) co-ad-
sorption. The transport of CO2 and N2 within the matrix and fractures of the coal seam is also ignored. This simplified model is defined to simulate primary CBM recovery to validate the established THM model for GM-ECBM recovery against rare data from field pilot studies.

\[
\begin{align*}
\phi_m = & \phi_m^0 + \frac{\phi_m^0 \Delta p_{(e+c)}}{k_m} \\
\phi_f = & \phi_f^0 + \frac{\phi_f^0 \Delta p_{(e+c)}}{k_m} \\
k = & k_0 \left( \frac{\phi_f}{\phi_f^0} \right) \\
& = k_0 \left( 1 + \frac{k_m}{k_m^0} \frac{\Delta p_{(e+c)}}{\Delta p_{(e+c)^0}} \right)^{3/2}
\end{align*}
\]

This model comprises the series of partial differential equations (PDEs), which can be implemented into COMSOL multiphysics software together with the thermal between the matrix and fractures and two-phase.

The established THM model is first validated against primary CBM recovery in situ, and then applied to simulate the process of GM-ECBM recovery. The evolutions of significant parameters including gas pressure, gas content, reservoir temperature, permeability, CH4 production, CO2 and N2 storage are comprehensively analyzed.

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### 3.1.2. Initial and boundary conditions

Coal seam #3 is characterized by an average thickness of 5–6 m, a relatively high permeability of 0.01–10 mD, a rich gas content of 8.27–21.54 m³/t, and an average burial depth of ~600 m [60]. In this study, the initial values of reservoir pressure, temperature, permeability and water saturation are set at 5.24 MPa, 305.5 K, 0.924 mD, and 0.82 respectively. The bottom hole pressure of the production well is 0.15 MPa, and the injection pressure of the gas mixture (CO₂, N₂) is 8 MPa for GM-ECBM recovery (no gas injection for primary CBM recovery). According to the local temperature and the temperature of the gas transported in pipeline, the temperature on the wall of injection well is set to 323.15 K. Table 2 lists the parameters used in the study. These parameters are mainly recovered from field tests and laboratory experiments, as well as details recorded in the public domain (Table 2).

As shown in Fig. 4, the slip condition is applied to the domain boundaries that are also insulated for mass transport and heat transfer, except for the injection and production wells. The model comprises 1558 tetrahedral elements and 32,650 degrees of freedom with the duration of both primary and enhanced recovery extending to 6000 days (~16.5 years).

### 3.2. Model validation by history matching

The simulated results for primary CBM recovery are compared with the historic production data from the Qinshu Basin. Sun et al. (2016) reported the historic production rate from an unstimulated production well subject to pressure depletion recovery in situ [37]. Fig. 5 presents the match between measured and modeled CH₄ production rate. Compared to the field data, the simulated production rate exhibits an initial transient decrease that rapidly steepens, followed by a gradual decrease with time. Two peak production rates are typically in simulation – the first may result from the rapid release of free gas in the coal seam near the production well with the second liberated by dewatering. This phenomenon is common in Qinshu Basin during pressure depletion production [37]. Gas transport in the coal seam is the combined results of competitive sorption, water seepage, and thermal and mechanical effects. The average relative error of CH₄ production rate is ~16.3%. Despite a slight deviation in the high/low rate stage, the modelling and field results for production rate are generally in good agreement. This illustrated that the proposed THM model can be used to simulate the primary CBM recovery, as well as extended to GM-ECBM recovery.

### 3.3. Modelling results of GM-ECBM and primary CBM recovery

We simulate the GM-ECBM recovery using the injection gas mixture 15%:85% CO₂:N₂ (representing flue gas) and injection pressure of 8.0 MPa to track the evolutions of gas pressure, gas content, reservoir temperature, permeability, CH₄ production and CO₂, N₂ storage to provide a process-based understanding of the entire process. The gas composition and injection pressure are retained constant during the entire span of injection.
3.3.1. Gas pressure evolution

Fig. 6 shows the distribution of gas pressure in the coal matrix for both primary CBM and GM-ECBM recoveries. The CH$_4$ pressure of both primary and enhanced recoveries gradually declines with time, with the early decline being faster than in the late stage (Fig. 6(a) and (b)). Compared to primary recovery, the CH$_4$ pressure during GM-ECBM recovery decreases more rapidly at early time due to the displacement effect of the injected gas mixture (CO$_2$, N$_2$), and then decreases more slowly in the later stage – this may result from the pressure compensation effect of continuous injection (Fig. 6(c) and (d)). As shown in Fig. 6(d), both CO$_2$ and N$_2$ pressures within the coal seam increase with the production times. As gas pressure drops due to production, CH$_4$ desorption-induced heat dissipation increases, resulting in a continuous decrease in reservoir temperatures distant from the injection well. For instance, the reservoir temperature at reference point P1 varies from 305.2 K (500 d) to 303.1 K (6000 d). Gas injection at an elevated temperature results in an apparent rise in reservoir temperature near the injection well (305.5 K to 323.5 K), as shown in Fig. 8(b). This phenomenon is increasingly more apparent near the production well. For instance, the reservoir temperature at reference point P1 varies from 305.2 K (500 d) to 303.1 K (6000 d). Gas injection at an elevated temperature results in an apparent rise in reservoir temperature near the injection well (305.5 K to 323.5 K), as shown in Fig. 8(b). However, due to the large volume and thermal mass of coal in situ, the migration rate of the apparent temperature-rise front is restricted, resulting in a limited extent of this elevated temperature zone. The elevated temperature results in an apparent rise in reservoir temperature during primary recovery (Fig. 8(a)). This phenomenon is increasingly more apparent near the production well. For instance, the reservoir temperature at reference point P1 varies from 305.2 K (500 d) to 303.1 K (6000 d). Gas injection at an elevated temperature results in an apparent rise in reservoir temperature near the injection well (305.5 K to 323.5 K), as shown in Fig. 8(b). However, due to the large volume and thermal mass of coal in situ, the migration rate of the apparent temperature-rise front is restricted, resulting in a limited extent of this elevated temperature zone. The sweep of N$_2$ flow accelerates CH$_4$ desorption and subsequent transport, and hence promotes a decrease in reservoir temperatures distant from the injection well even prior to the arrival of CO$_2$.

3.3.3. Reservoir permeability evolution

As demonstrated in Eq. (9), effective reservoir permeability is the competitive result of effects driven by changes in effective stress, gas.
ad/desorption induced swelling/shrinkage and thermal deformation.

Fig. 9(a) presents the evolution of reservoir permeability due to primary CBM recovery. Compared to the small decline in temperature and minor increase in effective stress, CH₄ desorption induced shrinkage dominates the evolution of permeability, leading to an increase in permeability, especially near the production well. As production time progresses, permeability ratio rises within the entire coal reservoir—increasing from \( \sim 0.997 \) (500 d) to \( \sim 1.132 \) (6000 d) at point P1.

Fig. 9(b) shows reservoir permeability along section A-B for GM-ECBM recovery and resulting from the influence of both gas mixture injection and CH₄ production. Before the arrival of the injected gas, permeability is dominated by the impact of desorption-induced shrinkage. Hence, permeability close to the production well has a rapid increase. The displacement effect of injected gas mixture occurs near the injection well. The N₂ flow with elevated N₂ concentration travels...
in advance of the CO$_2$, causing a feedback with increased CH$_4$ desorption and then transport towards the production well – this results in a faster early stage increase in permeability, as apparent in the permeability ratio curve at 500 d and 1000 d (Fig. 9(b)). CO$_2$ is retarded and travels slower, relative to N$_2$, but it has greater competitive adsorption capacity thus larger swelling effect when adsorbed on the coal matrix. Thus, CO$_2$ will play a leading role at the location of arrival. For example, permeability ratio declines dramatically near the injection well, from 0.966 (500 d) to 0.823 (6000 d).

3.3.5. Gas production and storage evolution

Fig. 10 presents the variation of CH$_4$ production and CO$_2$, N$_2$ storage. The CH$_4$ production rate of both primary and GM-ECBM recoveries first decline slightly, then climb to a peak value, before continuously declining to a residual magnitude (Fig. 10(a)). The peak production rates of primary and GM-ECBM recoveries are $\sim$2424 and $\sim$2958 m$^3$/d, respectively, appearing at $\sim$680 and $\sim$1540 d. This reveals that GM-ECBM recovery usually has an elevated but delayed CH$_4$ production peak. For GM-ECBM recovery (15%CO$_2$/85%N$_2$), the rapid transport of N$_2$ delivers a significant mass of N$_2$ injection and an early breakthrough. However, the slow migration limits the injection of CO$_2$, which has a low peak injection rate and a late breakthrough. Apparent from Fig. 10(b), the cumulative gas production/storage of both primary and GM-ECBM recoveries increases with time. The injected gas mixture significantly enhances the production of CH$_4$. Taking 6000 days of production as a reference, the cumulative CH$_4$ production of primary recovery is $8.22 \times 10^6$ m$^3$, while that of GM-ECBM recovery is $12.45 \times 10^6$ m$^3$, corresponding to an enhancement factor of 1.51.

4. Optimization of GM-ECBM recovery

The rationale for injecting the N$_2$:CO$_2$ gas mixture, rather than pure CO$_2$, is to avoid the significant reduction in reservoir permeability due to the CO$_2$-induced swelling. However, the excessive proportion of N$_2$ in the gas mixture may result in premature N$_2$ breakthrough in the production well. The high N$_2$ concentration in the produced gas flow will reduce the calorific value, thus forcing the premature shut-down of the production well. Therefore, key issues in optimizing the operation of GM-ECBM recovery, include: (i) how the gas production/storage performs under different Langmuir strain constants ($\varepsilon_L$), and (ii) what reasonable compositions of CO$_2$ in the injected gas mixture ($\eta_{CO_2}$) can be tolerated to maximize CH$_4$ recovery and the benefits of CO$_2$ sequestration.

The following investigation is completed with two scenarios representing injection at either constant-composition or with time-varying composition of the gases. Sensitivity studies are first applied to recover the optimized CO$_2$ composition for constant-composition injection with different CO$_2$ Langmuir strain constants ($\varepsilon_{L,2} = 0.0362$,
0.0482, 0.0602), followed by variable-composition injection with \( \varepsilon_{L2} = 0.0362 \).

### 4.1. Typical constant-composition gas mixture injection

The composition of the injected gas mixture is retained constant during the entire process of GM-ECBM recovery. According to the CO\textsubscript{2} composition in the injected mixture, the simulation schedule of constant-composition injection includes 11 cases, as shown in Fig. 11.

As N\textsubscript{2} has a low dynamic viscosity and adsorption capacity on coal, a higher N\textsubscript{2} (lower CO\textsubscript{2}) composition greatly promotes the transport of N\textsubscript{2} in the coal seam, leading to early breakthrough of N\textsubscript{2} in produced gas flow. When the produced N\textsubscript{2} + CO\textsubscript{2} mixture reaches a threshold, the production well should be shut down. This threshold is defined as when the ratio of N\textsubscript{2} + CO\textsubscript{2} production rate to CH\textsubscript{4} production rate is equal to 50\% (i.e., when N\textsubscript{2} + CO\textsubscript{2} fraction in the produced gas raises up to 33.3\% by volume). Additionally, uncecordingly low CH\textsubscript{4} production rates will result in the gas wells being shut down after 6000 days of production in the studied cases whether the threshold is reached or not.

Fig. 12 shows the CH\textsubscript{4} and N\textsubscript{2} + CO\textsubscript{2} production rates for different CO\textsubscript{2} Langmuir strain constants (\( \varepsilon_{L2} = 0.0362 \) (small swelling), 0.0482 (medium swelling), and 0.0602 (large swelling)). Both CH\textsubscript{4} and N\textsubscript{2} + CO\textsubscript{2} rates in the production well increases with the decrease in CO\textsubscript{2} composition. In Fig. 12(a), the peak CH\textsubscript{4} production rates for the injection of pure CO\textsubscript{2} (N\textsubscript{2}:CO\textsubscript{2} = 85:15) and pure N\textsubscript{2} are 2574, 2958 and 3779 m\textsuperscript{3}/d, respectively. There is no N\textsubscript{2} + CO\textsubscript{2} gas flow in the production well before their breakthrough. After the arrival of the injected mixture, the production rate of N\textsubscript{2} + CO\textsubscript{2} increases rapidly, especially when the CO\textsubscript{2} composition is low. A greater CO\textsubscript{2} composition in the mixture corresponds to a smaller production rate of N\textsubscript{2} + CO\textsubscript{2}.

We extract the CO\textsubscript{2} composition and the occurrence time of the shut-down threshold points for the different CO\textsubscript{2} Langmuir strain constants (\( \varepsilon_{L2} \)) in Fig. 12(a)–(c), and plot them in Fig. 13. A larger CO\textsubscript{2} composition corresponds to an increasingly delayed occurrence of the threshold point. For example, when \( \varepsilon_{L2} = 0.0602 \), the threshold occurs at 2200, 2920, 3520, 4420 and 5700 days for \( \eta_{CO2} = 0 \), 10\%, 15\%, 20\% and 25\% respectively. With an increase in \( \varepsilon_{L2} \), the CO\textsubscript{2} composition at threshold decreases. Specifically, the largest CO\textsubscript{2} compositions corresponding to \( \varepsilon_{L2} = 0.0362, 0.0482 \) and 0.0602 are 36.5\%, 30.2\% and 25.8\% respectively, at the intersection of the extension line and unconditional shut down line (6000 days), as shown in Fig. 13.

Fig. 14 presents the relationship between the CO\textsubscript{2} composition and cumulative magnitudes of CH\textsubscript{4} production and CO\textsubscript{2}, N\textsubscript{2} storage. With the CO\textsubscript{2} composition in the injected mixture increasing, the cumulative CH\textsubscript{4} production first inclines rapidly and then gradually declines. As a result, a greater Langmuir strain constant of CO\textsubscript{2} (\( \varepsilon_{L2} \)) leads to a smaller peak in cumulative CH\textsubscript{4} production. For example, the peak cumulative CH\textsubscript{4} production for \( \varepsilon_{L2} = 0.0362 \) is 10.58 × 10\textsuperscript{6} m\textsuperscript{3}, and the corresponding value for \( \varepsilon_{L2} = 0.0602 \) is 10.03 × 10\textsuperscript{6} m\textsuperscript{3}. Cumulative N\textsubscript{2} storage first decreases slowly then becomes more rapidly before finally slowing with the increase in CO\textsubscript{2} composition of the injected mixture.

As anticipated, the variation of cumulative CO\textsubscript{2} storage for different \( \varepsilon_{L2} \) varies widely. When the CO\textsubscript{2} composition in the injected gas mixture (\( \eta_{CO2} < 20 \)) is low, the CO\textsubscript{2} storages of \( \varepsilon_{L2} = 0.0362, 0.0482 \) and 0.0602 are all similar. However, when \( \eta_{CO2} > 20 \), the variation of cumulative CO\textsubscript{2} storage differs significantly with an increase in CO\textsubscript{2} composition – the CO\textsubscript{2} storage for \( \varepsilon_{L2} = 0.0362 \) continuously increases, while that for both \( \varepsilon_{L2} = 0.0482 \) and 0.0602 increases first, followed by a slight decrease. This is because the excessive matrix swelling induced by CO\textsubscript{2} adsorption plays significant role in the sharp reduction in reservoir permeability near the injection well, and thus restricts the transport of the injected gas mixture. The higher the CO\textsubscript{2} composition in the injected mixture, the greater the impact of swelling induced by CO\textsubscript{2} adsorption on gas production/storage. For example, when pure (100\%) CO\textsubscript{2} is injected into the coal seam, the cumulative CO\textsubscript{2} storages (6000 d) for \( \varepsilon_{L2} = 0.0362, 0.0482 \) and 0.0602 are 0.92, 2.37 and 7.78 × 10\textsuperscript{6} m\textsuperscript{3} respectively. As shown in Fig. 14, the optimal CO\textsubscript{2} composition when the production well achieves maximum cumulative CH\textsubscript{4} recovery generally falls in the range of 20–40\% depending on the coal swelling capacity to CO\textsubscript{2}. For instance, the optimal CO\textsubscript{2} composition for \( \varepsilon_{L2} = 0.0362 \) is 35\%.

### 4.2. Variable-composition gas mixture injection

We have previously discussed the effect of Langmuir strain constant of CO\textsubscript{2} on gas production/storage during constant-composition injection. Here, we select \( \varepsilon_{L2} = 0.0362 \) as a single base case to complete simulations of variable-composition injection to optimize the recovery schedule and maximize gas production/storage. The composition of the injected gas mixture is step-changed during the entire sequence of GM-ECBM recovery.

In this approach, the composition of the injected gas is changed after every period (step) of 1000 days. Defined by the variation of CO\textsubscript{2} composition of the injected mixture, the simulation schedule of variable-composition injection consists of 6 cases, e.g. Case 12: 90-70-50-35-20-10\%, Case 13: 60-50-40-35-30-20\%, Case 14: 50-45-40-35-30-25\%, Case 15: 25-30-35-40-45-50\%, Case 16: 20-30-35-40-50-60\%,
Case 17: 10-20-35-50-70-90%, as shown in Fig. 15. Finally, the optimum schedules for both constant- and variable-composition injection are compared to evaluate the impacts of variable CO2 composition on CH4 production and CO2 and N2 sequestration.

Fig. 16 shows the variations of gas (CH4, N2 and CO2) production rates during variable-composition GM-ECBM recovery. The CH4 production rate for all cases has a similar trend during the dewatering stage, but after the reservoir is dewatered, the CH4 production rates differ significantly between the various injection schedules. Cases 12–14 start with relatively high CO2 composition that gradually decreases over subsequent time steps – these result in a correspondingly low early CH4 production rate immediately following dewatering. Subsequently, the decrease in CO2 composition results in an increase in CH4 production rate and also a rapid increase in the N2 + CO2 production rate, resulting in early breakthrough of the injected mixture and early reaching of the shutdown threshold for the production well.

Fig. 12. Gas production rate for constant-composition gas injection for different Langmuir strain constants of CO2: (a) $\varepsilon_{L2} = 0.0362$; (b) $\varepsilon_{L2} = 0.0482$, and (c) $\varepsilon_{L2} = 0.0602$ respectively.

Fig. 13. The occurrence time and CO2 composition of threshold points.

Fig. 14. Relationship between CO2 composition in the injected mixture and cumulative gas production/storage.
the CO2 composition in the injected gas mixture increases, reservoir
lated cases for the variable composition GM-ECBM recovery.

Thus, case 17 is the preferred injection schedule among all the simu-
ECBM may be ine
in a single injection schedule

cases 15 –

Cases 15–17 begin with a relatively low CO2 composition and
continue with gradual increase in CO2 concentration. In this case, the
placed CH4 is driven by injected N2 flow towards the production well,
and results in a rapid enhancement in early production im-
immediately following dewatering. In Fig. 16, the CH4 production rate of
cases 15–17 increases to relatively high levels early in production. As
the CO2 composition in the injected gas mixture increases, reservoir
permeability rapidly decreases due to excessive matrix swelling,
leading to a sharp decrease in N2 + CO2 production rate. Consequently,
the shutdown threshold for production well is not reached until the end
of production (6000 days).

As illustrated in Fig. 17, injection sequences that begin with a low
CO2 composition that gradually increases, provides an optimal balance
between reaching an early shut-down N2 threshold and excessive ma-
trix swelling induced by CO2 adsorption – this results in a prolonged
the production time. The maximum cumulative CH4 production
(11.26 × 106 m3) and CO2 sequestration (7.78 × 106 m3) are obtained
when the early breakthrough and early attainment of shut-down
threshold in the production well. Comparing with primary CBM rec-
covery, the recovery ratios of pure CO2, optimal constant injection and
optimal variable injection are 59.4%, 64.2% and 68.4%, with en-
hancement ratios of 1.19, 1.29 and 1.37, respectively. This illustrates
that the approach of variable composition injection for GM-ECBM re-
cover is an effective method to improve coalbed methane production.
And the model exercised in this work provides a rational means to
define controlling processes and resulting responses.

Note that the optimal composition of the injected gas will vary
among different sites and geological conditions, and the impacts of well
spacing, injection pressures and other parameters, including the de-
inition of economic conditions controlling recovery. However, an op-
timal variable-composition schedule for gas mixture injection can al-
ways be determined according to the actual situation.

5. Conclusions

An improved thermo-hydro-mechanical (THM) model is developed
to couple the responses of coal deformation, mass transport of a mixture
of ternary gases (CH4, CO2 and N2) and water together with heat
transfer. This model is first validated then applied to simulate gas-
mixture enhanced coalbed methane (GM-ECBM) recovery. Sensitivity
analyses are conducted on the control of key parameters together with
optimization of recovery schedules. These simulations provide an im-
proved understanding on the processes controlling GM-ECBM recovery.
The following conclusions are drawn:

(1) Injection of gas mixture (CO2, N2) significantly promotes coalbed
methane recovery. This is reflected in an elevated peak production
rate and an increased cumulative production. Both CH4 pressure
and content decrease rapidly at early time due to the displacement
of the injected gas followed by a slowing in this rate.

(2) As gas pressure drops due to production, CH4 desorption-induced
heat dissipation increases, resulting in a continuous decrease in
reservoir temperature near the production well. This is com-
plemented by a rapid temperature increase at the injection well due
to the injection of the hot recovery gas. The sweep of N2 accelerates
CH4 desorption and subsequent transport, and hence promotes a
decrease in reservoir temperatures distant from the injection well
even prior to the arrival of CO2.

(3) Permeability evolution is controlled by both gas mixture injection
and methane production. Before the arrival of the CO2/N2 mixture
front, permeability increase is dominated by CH4 desorption-in-
duced shrinkage. After the arrival of the front, permeability is
dominated by competitive result of CH4 desorption-induced
shrinkage and N2/CO2 adsorption-induced swelling. As a result, a
rapid increase in permeability in the early stages is followed by a
dramatic decrease at later stages.

(4) An increased Langmuir strain constant to CO2 reduces critical
compositions of CO₂ in the injected mixture required to reach the threshold for well shut down. The optimal CO₂ composition for constant-composition GM-ECBM generally falls in the range of 20–40% depending on coal swelling susceptibility to CO₂. Beginning with injection of low CO₂ composition, following by a sequential increase (of CO₂ composition), results in an optimal balance between avoiding the reaching of an early threshold (N₂) and large matrix swelling (CO₂). Of the case studied, the gas recovery ratio of optimal variable-composition mixture/schedule is 68.4% compared to 64.2% of constant-composition, illustrating the superiority of variable-composition injection during GM-ECBM recovery.

The fully coupled THM model developed in this work not only offers useful framework to investigate important technical challenges associated GM-ECBM, but can also be applied to other forms of unconventional gas extraction, and other fields such as CO₂ geological sequestration, underground coal gasification, and geothermal development.

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Notes

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