CO_2 Sequestration in Deep Unminable Coal Seams: A Numerical Study

A.S. Ranathunga, M.S.A. Perera and P.G. Ranjith
Department of Civil Engineering, Monash University, Australia

ABSTRACT: The application and optimization of the enhanced coal bed methane (ECBM) recovery process requires numerical modeling tools to reduce the complexity, cost and extensive time associated with laboratory and field experiments. Therefore, this research work was carried out to comprehend and establish the technical feasibility of CO_2 driven enhanced CBM recovery in coal seams. A regional scale underground coal block was modelled using a commercial reservoir simulator, COMET3 and major CBM enhancing techniques were studied. According to the results CBM production enhancement created by the CO_2-ECBM technique found to be much more productive compared to the water production created enhancement, if an appropriate injection pressure is maintained. Further, 310% increment of CBM production can be observed from a 100% CO_2 injection pressure increment. However, increasing the injection pressure should be done in a well-controlled manner to avoid any significant fracture formation in the seam that may lead to CO_2 leakage.

1 INTRODUCTION

With the process of industrialization and modernization, carbon dioxide (CO_2) emission is becoming a main concern which directly leads to the global warming. Various approaches have been proposed to effectively address the problem by significantly reducing the amount of greenhouse gas in the atmosphere. Among those methods, CO_2 sequestration in deep un-mineable coal seams is recognized as one of the most promising method for the cost and safety consideration.

Coal seams exist at various depths ranging from 100m to more than 1000m and in natural coal beds, most of the CO_2 (98%) exists in an adsorbed phase, which forms a relatively stable state and reduces the risk of leakage (Ranathunga et al., 2014). Additionally, CO_2 storage capacity in coal seams of same volume is much higher with its large surface area compared to other geological sequestration means such as saline aquifers (Ranathunga et al., 2014). Further, it has been estimated that 60 Trillion Cubic Feet of recoverable coal bed methane resources are available in Australia (White et al., 2005). Due to the fact that CO_2 has higher adsorption ability than CH_4, the injection of CO_2 would force the originally existing CH_4 to release, which enhances the coal bed methane recovery. As CH_4 is treated as a clean energy source with high efficiency, it becomes an ideal make-up for the energy shortage.

Coal mass can be defined as a naturally-fractured reservoir for gas movement. The movement of gases through this coal mass structure depends on the permeability of the coal seam itself, which may be governed by Darcian Law or non-linear laminar flow and the intrinsic permeability of the coal matrix, which is governed by Fickian diffusion. Therefore, the amount of CO_2 that can be stored in the coal mass is highly dependent on coal's physical and chemical properties. However, the process of CO_2 sequestration in deep coal seams remains in the experimental stage as many aspects need to be studied before it can be put into practice (White et al., 2005).

Generally, coal mass has dual porosities consists of primary and secondary porosity systems and the interaction of these porosities leads for many complexities (Coll et al., 1994). Experimental and numerical modelling studies can help to provide a better understanding of the flow phenomenon in coal. To date, many researches has developed field-scale models for flow in porous rock masses using different computer codes, such as TOUGH 2 (Carneiro, 2009), COMSOL (Liu and Smirnov, 2009), FEMLAB (Holzbecher, 2005) and COMET3 (Perera et al., 2015) which can be used to simulate gas and water flow in coal. Among them, COMET3 is a conventional and coal bed methane reservoir simulator, which can simulate single or two phase flow through single, dual or triple porosity reservoirs, such as coal or shale as well as conventional reservoirs (Pekot and Reeves, 2002).

The main objective of this study is to develop a 3D numerical model using COMET3 to simulate the CO_2 sequestration process to replicate the field conditions using data for Australian coal seams. Further, this research work was carried out as a preliminary study to comprehend and establish the technical feasibility of CO_2 driven enhanced CBM recovery in Australian coal.

2 METHODOLOGY

2.1 *Governing equations used in the modelling process by COMET3*

Fluid flow in the rock mass is modelled by using mass conservation equations for water (Eq. (1)) and gas (Eq. (2)) (Sawyer et al., 1990).

$$\nabla.\left[b_g M_g\left(\nabla p+\gamma \nabla Z\right)+R_{sw} b_w M_w\left(\nabla p_w+\gamma_w \nabla Z\right)\right]_f+q_m+q_g=\left(\frac{d}{dt}\right)\left(\varnothing b_g S_g+R_{sw}\varnothing b_w S_w\right)_f \quad (1)$$

$$\nabla.\left[b_w M_w\left(\nabla p_w+\gamma_w \nabla Z\right)\right]_f+q_w=\left(\frac{d}{dt}\right)\left(\varnothing b_w S_w\right)_f \quad (2)$$

where $\boldsymbol{b_n}$ (n=g or w) is the gas or water bulking factor, $\boldsymbol{\gamma_n}$ (n=g or w) is the gas or water gradient, $\boldsymbol{R_{sw}}$ is the gas solubility in water, $\boldsymbol{\phi}$ is the fracture porosity, $\boldsymbol{Z}$ is the elevation, $\boldsymbol{q_g}$ is the gas flow rate, $\boldsymbol{q_w}$ is the water flow rate, $\boldsymbol{q_m}$ is the matrix gas flow rate, $\boldsymbol{M_n}$ (n=g(gas) or w (water)) = $\boldsymbol{kk_m/\mu_m}$, is the phase mobility ($\boldsymbol{k}$-permeability, $\boldsymbol{k_m}$-matrix permeability, $\boldsymbol{\mu_n}$-phase viscosity), $\boldsymbol{S_n}$(n=g or w) is the gas or water saturation and $\boldsymbol{P_n}$ (n=g or w) is the gas or water pressure. Using extended Langmuir model (Arri et al., 1992) gas adsorption was calculated (Eq. (3)).

$$C_i\left(P_i\right)=\frac{V_{Li}P_i}{P_{Li}\left[1+\sum_{j=1}^{3}\left(\frac{P}{P_L}\right)_j\right]},\ i=1,2 \quad (3)$$

where $\boldsymbol{V_{Li}}$ is the Langmuir volume, $\boldsymbol{P_{Li}}$ is the Langmuir pressure, $\boldsymbol{P_i}$ is the partial pressure of the gas component, $\boldsymbol{C_i(P_i)}$ is the adsorbed gas concentration at $\boldsymbol{P_i}$ and **P** is the total pressure.

Gas flow through the matrix is modelled using Fick's law of diffusion (Eq. (4)).

$$q_{mi}=\left(\frac{V_m}{\tau_i}\right)\left[C_i-C_i\left(P_i\right)\right],i=1,2 \quad (4)$$

where $\boldsymbol{q_{mi}}$ is the gas component flow, $\boldsymbol{V_m}$ is the bulk volume of the matrix element, $\boldsymbol{\tau_i}$ is the sorption time and $\boldsymbol{C_i}$ is the average matrix gas concentration of gas component *i*.

The corresponding permeability variations in the coal matrix and fracture system were simulated using the Advanced Resources International (ARI) model (Eq. (5) and Eq. (6)):

$$\varphi=\varphi_i\left[1+c_P\left(P-P_i\right)\right]-c_m\left(1-\varphi_i\right)\left(\frac{\nabla P_i}{\nabla C_i}\right)\left(C-C_i\right) \quad (5)$$

$$\frac{k}{k_i}=\left(\frac{\varphi}{\varphi_i}\right)^n \quad (6)$$

where $\boldsymbol{c_p}$ is the pore volume compressibility $\boldsymbol{c_m}$ is the matrix shrinkage compressibility, $\boldsymbol{\phi}$ is the coal mass porosity, $\boldsymbol{\phi_i}$ is the initial coal mass porosity, $\boldsymbol{P}$ is the reservoir pressure, $\boldsymbol{P_i}$ is the initial reservoir pressure, $\boldsymbol{C}$ is the reservoir concentration, $\boldsymbol{C_i}$ is the initial reservoir concentration, $\boldsymbol{k}$ is the reservoir permeability and $\boldsymbol{k_i}$ is the initial reservoir permeability.

2.2 *Model Development*

A 500m x 500m x 20m un-minable coal seam lying 1000m below the ground surface was considered for the model development, and gas production and injection were carried out at opposite corners of the coal seam, as shown in Fig.1. The model parameters used for the simulation are shown in Table 1.

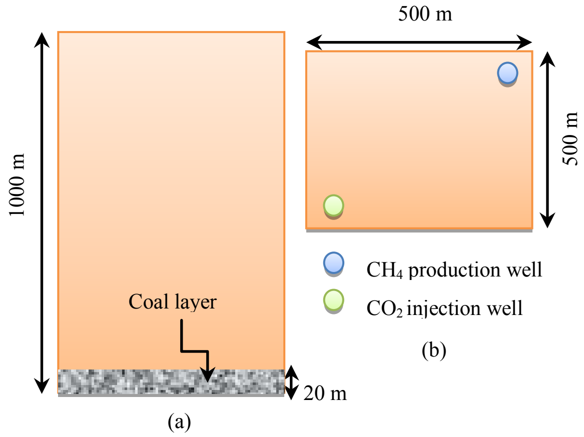

Fig. 1 Block dimensions used for reservoir simulation (a) Cross section and (b) Plan view.

After developing the model, firstly the ordinary methane (CH_4) production capacity (without using any enhancing technique) of the coal seam was examined for a duration of 50 years (18250 days). The production rate was then enhanced by pumping out the forming water at 25 m^3/day rate for 10 years. In this stage, the production well was used as a water pumping well to deplete the pressure inside the coal seam. Water production was terminated after 10 years and the well was then used to produce CH_4 from the pressure-reduced coal seam for the remaining 40 years while keeping the injection well shut in operation condition for all the cases.

The CO_2-ECBM technique was then examined by injecting CO_2 into the coal seam at 12 MPa injection pressure after the first 10 years for 40 years. Effective factors for the CO_2-ECBM process were then examined to identify possible ECBM process optimization measures. Next, the effect of CO_2 injection pressure was examined by changing the CO_2 injection pressure (12, 14, 18, 20, 22 and 24 MPa).

Table 1. Model Parameters

Model parameter	Value
Reservoir temperature (^oC)	50
Coal seam initial permeability (mD)	2 mD
Well bore diameter (m)	0.1
Cleat porosity (%)	0.24
Langmuir constants on equilibrium moisture in-situ basis	
Langmuir volume for methane (Sm^3/ton)	5.07
Langmuir pressure for methane (kPa)	5110
Langmuir volume for CO_2 (Sm^3/ton)	29.11
Langmuir pressure for CO_2 (kPa)	5780
Exponent of pressure dependent permeability(n)	3.0
Differential matrix swelling factor of CO_2	2.0
Pore volume compressibility (kPa^{-1})	3.0×10^{-4}
Matrix shrinkage compressibility (kPa^{-1})	2.0×10^{-6}
Initial pore pressure	$P_o=h\times\rho_w\times g$*

* h is the depth, ρ_w is the water density and g is the gravitational acceleration

3 RESULTS AND DISCUSSION

3.1 *Comparison of CBM production enhancement techniques*

Fig. 2 compares the effects of the enhancement techniques on CH_4 production. A substantial CBM production enhancement through water removal can be seen in the Fig. 2, because removal of water from the coal seam reduces the pore pressure, which enhances the CH_4 desorption rate (Fujioka et al., 1995). For the considered coal seam, 12 MPa injection pressure creates insignificant CBM production enhancement (see Fig. 2). Because, when CO_2 is injected, a pore pressure development occurs in the coal seam, which prevents CH_4 release from the coal seam unless a sufficient flow rate is sustained. The pore pressure for the considered coal seam is closer to 10 MPa (for 1000m depth). According to available flow models, in order to maintain a proper flow rate through any medium, there should be a sufficient pushing force created by the pressure gap between the injecting fluid and the medium. Apparently, 12 MPa injection pressure is insufficient to create such a force. This finding confirms the need for an appropriate numerical model to decide the required CO_2 injection pressure for field-scale CO_2-ECBM projects to achieve maximum production enhancement.

3.2 *Effect of CO_2 injection pressure on CBM production*

The effect of CO_2 injection pressure on enhanced CH_4 production was then examined by changing CO_2 injection pressure (12, 14, 16, 18, 20, 22 and 24 MPa) and all other variables inserted in the model were kept constant. According to Fig. 3, CBM production and coal seam permeability (near the injection point) increases exponentially with increasing CO_2 injection pressure. The increase of injection pressure from 12 to 24 MPa (100%) causes an increment of the CBM production to increase by around 310% and coal seam permeability by around 191%. This is because; increased injection pressure produces a greater CO_2 adsorption capacity in the coal seam, which augments the CH_4 desorption rate (Bae and Bhatia, 2006) (see Fig. 4) and this seam permeability increment under increased injection pressure enhances CO_2 flow ability through the seam, and corresponding CO_2 adsorption process into the coal matrix, which consequently enhances the CH_4 production (Fig. 4).

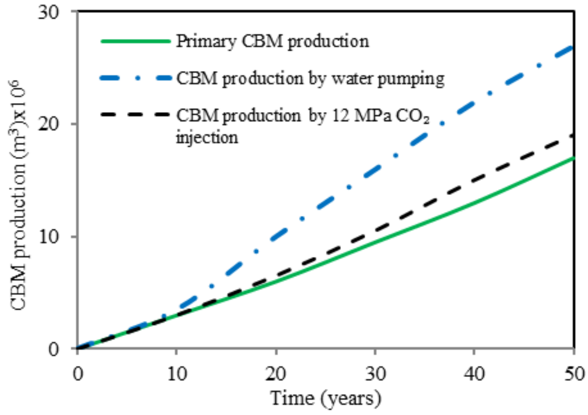

Fig. 2 Comparison of CBM production enhancement techniques

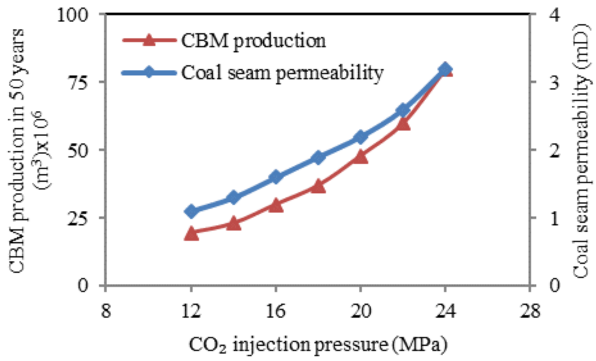

Fig. 3 Effect of CO_2 injection pressure on CBM production and coal seam permeability

However, it should be noted that too high injection pressures may cause hydraulic fractures to be created in the coal seam, resulting in a risk of injected CO_2 back-migration into the atmosphere. According to Hawkes et al. (2005), the most critical orientation for the opening of fractures is in a plane normal to the minimum in-situ stress component (σ_3). Once the pore pressure (P_u) exceeds σ_3, it can form fractures and this phenomenon was used to identify fracture formations in the coal seam. Fracture pore pressure was directly taken from the COMET 3 simulator and Eq. (7) was used to calculate the third principal stress at 1000m assuming it is equal to gravitational stress (Sheorey, 1994).

$$\sigma_g = h \times \rho_r \times g \quad (7)$$

where ***h*** is the depth, $\boldsymbol{\rho_r}$ is the rock density and ***g*** is the gravitational acceleration and according to Eq. (7), third principal stress is 24.5 MPa. Therefore, for safety reasons, the maximum safe CO_2 injection pressure can be selected as 20 MPa for the modeled coal seam.

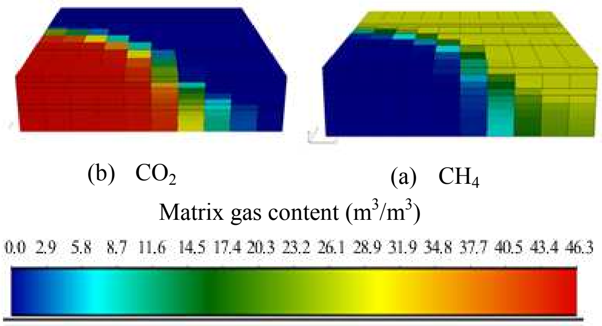

Fig. 4 CO_2 and CH_4 content in coal seam after 50 years for 20 MPa CO_2 injection pressure

4 CONCLUSIONS

The application and optimization of the enhanced coal bed methane (CBM) recovery process requires numerical modeling tools to reduce the complexity, cost and extensive time associated with laboratory and field experiments. Therefore a 3-D numerical model was developed using the COMET 3 numerical modeling tool to simulate 50 years of CH_4 production from a regional scale coal seam and the possible major CBM production enhancement techniques were tested.

According to the results CBM production enhancement created by the CO_2-ECBM technique seems to be much more productive compared to the water production created enhancement, if an appropriate injection pressure is maintained. Simply injecting CO_2 into the coal seam does not enhance CBM production and it is necessary to maintain an appropriate injection pressure to recover an optimum amount of CBM.

Regarding the injection pressure effect, ECBM production exponentially increases with increasing CO_2 injection pressure, due to the expanded pore space and enhanced CO_2 adsorption capacity at increased CO_2 injection pressures. Interestingly, 310% increment of CBM production can be observed from a 100% CO_2 injection pressure increment (12 to 24 MPa). However, increasing the injection pressure should be done in a well-controlled manner to avoid any significant fracture formation in the seam that may lead to CO_2 leakage.

5 RECOMMENDATIONS

It is recommended to evaluate other important parameters such as coal seam properties and injecting gas properties in order to comprehend the feasibility of using CO_2-ECBM for Australian coal seams. Moreover, a series of experimental studies should be performed and used in conjunction with the numerical model for more validated results.

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