ABSTRACT

The Allison CO₂-ECBM pilot, augmented by detailed reservoir-characterization work carried out in a recently completed DOE-sponsored research project, provides a unique benchmark test case for reservoir simulation of ECBM recovery and associated CO₂ storage. This paper presents the results of a reservoir-simulation study, focusing on the impact of matrix shrinkage and swelling on ECBM production and CO₂ injectivity. Using the field gas production and CO₂-injection rates as input to the Imperial College in-house ECBM/CO₂ storage simulator, METSIM2, with its newly implemented dynamic permeability model simulator, the injecting bottomhole pressures, produced-gas composition at the two wells experiencing noticeable CO₂ breakthrough, and the producing bottomhole pressures were satisfactorily history matched.

INTRODUCTION

The Allison Unit pilot, which is located in the northern New Mexico part of the San Juan Basin, represents the first field trial on CO₂-ECBM. CO₂ injection started in April 1995, after approximately six years of primary production, and was suspended in August 2001. As part of the U.S. DOE-funded Coal-Seq project looking into the feasibility of CO₂ storage in deep, unminable coalbeds, a detailed reservoir-characterization and field history-matching study of the Allison pilot was carried out, the results which have been recently made public [1]. The study area (Figure 1) consists of 16 producing wells, four CO₂-injecting wells, and one pressure-observation well. The five wells at the centre of the pilot roughly form a 5-spot pattern, with the four injectors positioned at the periphery of the pattern.

The published Allison CO₂-ECBM pilot data presented a unique opportunity to perform a benchmarking test with the Imperial College in-house simulator METSIM2, soon after the completion of the Geo-Seq code comparison study [2] led by the Alberta Research Council, Canada, in which the performance of METSIM2 has been fully verified against widely used commercial ECBM software and other research codes. The unique feature of METSIM2 is the implementation of a dynamic permeability model recently developed by the authors [3, 4] to describe permeability changes in coalbeds during primary and CO₂-ECBM recovery. This permeability model has been validated using the primary-recovery permeability data from the San Juan Basin coalbed wells.

This paper presents the permeability model developed together with some of the main results of this simulation study, focusing on the impact of matrix shrinkage and swelling on methane production and CO₂ injectivity.

A MODEL FOR CHANGES IN COALBED PERMEABILITY DURING ENHANCED RECOVERY

Coal seams may be characterized by two distinctive porosity systems: a well defined and almost uniformly distributed network of natural fractures (cleats), and matrix blocks containing a highly heterogeneous porous structure between the cleats, Figure 2. The cleat spacing is very uniform and ranges from the order of millimetres to centimetres. Permeability of coal is recognized as the most important parameter for commercial coalbed methane production. As in a fractured conventional reservoir, the permeability of coalbeds is due primarily to the network of natural fractures. Being normal to the bedding plane and orthogonal to each other, the face and butt cleats in coal seams are usually sub-vertically orientated. Thus changes in the cleat permeability can be considered to be dependent on the prevailing effective horizontal stresses that act across the cleats, rather than the effective vertical stress, defined as the difference between the overburden stress and pore pressure.

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An important characteristic of coal is that it is known to shrink on desorption of gas and to swell again on resorption. During primary methane production, two distinct phenomena are known to be associated with reservoir-pressure depletion, with opposing effects on coal permeability [5]. The first is reservoir compaction, which causes an increase in the effective horizontal stress as the reservoir is confined laterally. The second is gas (primarily methane) desorption from the coal matrix resulting in coal-matrix shrinkage, and thus a reduction in the horizontal stress and an increase in cleat permeability.

The effect of matrix shrinkage on coalbed reservoir permeability was first quantified by Gray [5]. Since then a number of theoretical and empirical permeability models have been put forward. Among them, the one that is most widely used is the Palmer and Mansoori model [6, 7]. Building upon this experience, Shi and Durucan [3, 4] recently proposed a new model to estimate changes in coalbed permeability during primary and enhanced CBM recovery. In the new model, coalbeds are idealized to have a bundled-matchstick geometry and thus coalbed permeability is controlled by the prevailing effective horizontal stress. The following exponential relationship between permeability and change in the effective horizontal stress ($\sigma - \sigma_0$) can thus be derived [8]:

$$k = k_0 e^{-3c_f(\sigma - \sigma_0)}$$

where $k_0$ and $\sigma_0$ denote permeability and stress at in situ state, and $c_f$ is the cleat-volume compressibility with respect to changes in the effective horizontal stress normal to the cleats.

Assuming that matrix shrinkage is directly correlated to the volume of desorbed gas, change in the effective horizontal stress is given by [3]:

$$\sigma - \sigma_0 = -\frac{\nu}{1-\nu}(p - p_0) + \frac{E\alpha_s(V - V_0)}{3(1-\nu)}$$

where $\alpha_s$ is the volumetric shrinkage coefficient, and $V$ and $V_0$ are the gas contents (ft$^3$/ft$^3$) corresponding to reservoir pressures $p$ and $p_0$ respectively. $E$ and $\nu$ are the Young’s modulus and Poisson’s ratio, respectively, of the coalbed.

Eqs. 1 and 2 describe how coalbed permeabilities vary with pore pressure under reservoir conditions. The two terms on the right-hand side of Eq. 2 are referred to as, respectively, the cleat-compression and matrix-shrinkage terms. As $p$ is decreased from $p_0$, the cleat-compression term is positive, while the matrix-shrinkage term is negative.
The magnitude of \((\sigma - \sigma_0)\) is, therefore, determined by the relative strength of these two opposing terms. A detailed analysis of how the horizontal stress changes as a coalbed is depleted and the validation of this permeability model have been presented elsewhere [3, 4].

The permeability model presented above has been extended to provide a first-order estimation of the coalbed-permeability changes during CO\(_2\) storage and ECBM recovery [4]. For an \(n\)-component gas mixture, Eq. 2 is replaced by:

\[
\sigma - \sigma_0 = -\frac{v}{1-v} (p - p_0) + \frac{E}{3(1-v)} \left( \sum_{j=1}^{n} \alpha S_j V_j - \sum_{j=1}^{n} \alpha S_j V_{j0} \right)
\]

(3)

where \(\alpha S_j\) and \(V_j\) are the volumetric shrinkage/swelling coefficient and adsorbed gas volume (ft\(^3\)/ft\(^3\)) for component \(j\). The permeability is again calculated using Eq. 1. There is laboratory evidence [9] that the swelling coefficient is adsorbate specific, and generally increases with gas affinity to coal.

The permeability model (Eqs. 1 and 3) has been recently implemented in the Imperial College in-house ECBM simulator, METSIM2, to compute changes in coalbed permeability during ECBM recovery or CO\(_2\) storage. The permeability across the entire reservoir is updated at each time step. The extended Langmuir isotherm is used to describe adsorption/desorption of a multi-component gas mixture in coal:

\[
V_{Ej} = \frac{\sum_{j=1}^{n} b_j \rho_j b_j}{1 + \sum_{j=1}^{n} b_j \rho_j} = \frac{V_{jL} \rho_j Y_j b_j}{1 + p \sum_{j=1}^{n} b_j Y_j}
\]

(4)

where \(V_{Ej}\) is the adsorbed volume (ft\(^3\)/ft\(^3\)) of gas component \(j\), which is in equilibrium with the free gas phase in the cleats, \(V_{jL}\) and \(b_j\) are Langmuir parameters for gas component \(j\), and \(p_j\) is the partial free gas pressure, \(\sum p_j = p\) and \(Y_j = p_j / p\).

**ALLISON PILOT RESERVOIR SIMULATION**

The reservoir simulation effort reported here benefited from the previous work [1] in a number of respects, including reservoir characterization and model construction. The main results of the reservoir-characterization work are summarized here.

**Previous Work by Reeves et al. [1]**

The Allison Unit wells produce from three Upper Cretaceous Fruitland Formation coal seams, referred to as Yellow (shallowest), Blue and Purple (deepest). The seams dip gently towards the south-southwest in the study area. The aggregate thickness of the three seams ranges from 35 to 48 ft, with a mean net thickness of 43 ft (Yellow: 22 ft; Blue: 10 ft; and Purple: 11 ft). It is reported that the three seams have different sorption characteristics (Langmuir parameters), although little variation in Langmuir volume was found in a given seam. The Langmuir constants for CH\(_4\) and CO\(_2\), together with the estimated methane gas-in-place breakdown, for the three seams are given in Table 1.

**TABLE 1: MEASURED LANGMUIR PARAMETERS AT ALLISON UNIT (AFTER [1]).**

<table>
<thead>
<tr>
<th></th>
<th>CH(_4)</th>
<th>CO(_2)</th>
<th>Gas-in-place</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(V_{L}), SCF/ton (ft(^3)/ton)</td>
<td>(1/b), psi</td>
<td>(V_{L}), SCF/ton (ft(^3)/ton)</td>
</tr>
<tr>
<td>Yellow</td>
<td>448 (21.0)</td>
<td>525</td>
<td>652 (30.5)</td>
</tr>
<tr>
<td>Blue</td>
<td>305 (16.4)</td>
<td>484</td>
<td>443 (23.8)</td>
</tr>
<tr>
<td>Purple</td>
<td>393 (19.4)</td>
<td>519</td>
<td>576 (28.4)</td>
</tr>
</tbody>
</table>
The relative-permeability curves, together with the porosity distribution, for the Allison pilot study area were derived using a novel procedure developed by Burlington Resources, the operator of the field. Porosity values ranging from 0.05% in the northwest to 0.3% in the southwest are reported. A minimum porosity value of 0.15% was used by Reeves et al. [1] in their reservoir simulation study, as the lower porosity values were judged to be unrealistic.

Field characterization of the (absolute) permeability was based upon the pressure-buildup tests performed in May 2000 on 12 wells in the Allison Unit, of which eight are inside the study area. The effective gas permeability, skin factor, and reservoir pressure were estimated by analyzing the pressure data. The absolute permeability was then derived from the obtained effective gas permeability values. A correlation between the relative gas permeability and the absolute permeability was developed and applied to those wells for which no well-test data were available. The results show that permeability, as it stood in May 2000, ranged from 30 to 150 md, with the higher values mainly confined to within the central 5-spot pattern (Figure 3).

Figure 3: Permeability map for Allison Unit (after [1]).

A Simplified Reservoir Model

The reservoir model used in [1] consisted of three layers, each representing one of the coal seams (Yellow, Blue or Purple). The model domain covered an area of approximately 7,100 acres and was divided into 33 x 32 = 1056 grid blocks, 881 of which were active. Figure 4 presents the model domain, together with the grid showing the well locations, which has been redrawn from the original work. This reservoir model was adopted in the current study with some simplifications due to the lack, in digital format, of such reservoir data as the net thickness isopach, absolute permeability and porosity maps. Firstly, the three layers were assumed to be of uniform thickness, and were assigned the mean thickness of the three seams, namely 22ft, 10ft and 11ft, respectively. Secondly, the reservoir model was assigned homogenous reservoir properties including permeability (100 md) and porosity (0.2%), with the exception of the Langmuir parameters, which were layer-specific (Table 1). Although somewhat arbitrary, these values were chosen as being representative of the central 5-spot pattern area of the reservoir. Table 2 summarizes the key reservoir properties used in this study.

The Impact of Matrix Shrinkage/Swelling on Permeability

In addition to the Langmuir constants, the permeability model (Equations 1 and 3) requires five parameters, namely $E$, $\nu$, $a_{SCCH_4}$, $a_{SCO_2}$ and $c_f$, as input for a given coalbed reservoir. For accurate modelling of permeability changes during CO$_2$-ECBM recovery, it is crucial to use parameters representative of the coalbed reservoirs under consideration. The permeability model has been successfully used to match the primary-recovery permeability data
at three San Juan Basin coalbed wells [3, 4]. The history-matched permeability parameters were $E = 420,000$ psi, $\nu = 0.35$, $\alpha_S V_L = 0.0128$ and $c_f = 0.001 - 0.002$ psi$^{-1}$. The elastic properties ($E$ and $\nu$) and the cleat-volume compressibility $c_f$ were used directly in this study. As the shrinkage volumetric strain ($\alpha_S V_L$) was obtained for coalbeds containing about 10% CO$_2$ in produced gas stream, it was scaled down to 0.0112 for pure methane and then divided by the Langmuir volume for the Yellow seam ($V_L = 21$ ft$^3$/ft$^3$) to yield a first-order estimation for $\alpha_{SCOH_4}$.

Table 2 lists the values of these four parameters used in this study.

**Table 2: Key Reservoir Properties and Parameters Used in the Simulation Study Reported in This Paper.**

<table>
<thead>
<tr>
<th>Reservoir property</th>
<th>Values used</th>
<th>Sources</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial pressure</td>
<td>1650 psi</td>
<td>[1]</td>
</tr>
<tr>
<td>Temperature</td>
<td>120°F</td>
<td>[1]</td>
</tr>
<tr>
<td>Gas composition</td>
<td>95.5% CH$_4$ 4.5% CO$_2$</td>
<td>[1]</td>
</tr>
<tr>
<td>Sorption time</td>
<td>10 days</td>
<td>[1]</td>
</tr>
<tr>
<td>Initial water saturation</td>
<td>0.95</td>
<td>[1]</td>
</tr>
<tr>
<td>Initial permeability</td>
<td>100 md</td>
<td>Permeability map (Figure 3)</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.2%</td>
<td>Porosity map [1]</td>
</tr>
<tr>
<td>Langmuir constants</td>
<td>Table 1</td>
<td>[1]</td>
</tr>
<tr>
<td>Relative-permeability curves</td>
<td>Figure 5</td>
<td>[1]</td>
</tr>
<tr>
<td>Young’s modulus, $E$</td>
<td>420,000 psi</td>
<td>[3,4]</td>
</tr>
<tr>
<td>Poisson’s ratio, $\nu$</td>
<td>0.35</td>
<td>[3,4]</td>
</tr>
<tr>
<td>Shrinkage/Swelling coefficient, $\alpha_S$</td>
<td>CH$_4$: $5.333 \times 10^{-4}$ ft$^3$/ft$^3$</td>
<td>[3,4]</td>
</tr>
<tr>
<td></td>
<td>CO$<em>2$: $\alpha</em>{SCO2}/\alpha_{SCOH4} = 1.276$</td>
<td>History matched</td>
</tr>
<tr>
<td>Cleat-volume compressibility, $c_f$</td>
<td>0.001 psi$^{-1}$</td>
<td>[3, 4, 8]</td>
</tr>
</tbody>
</table>
Assuming $V_j = V_{ij}$ in Eq. 3, Equations 1, 3 and 4 can be used to compute changes in permeability as a function of reservoir pressure and free-gas composition without resorting to a simulator. Permeability behaviour of a coalbed around producing and injecting wells is of particular interest here. Two scenarios with different CO$_2$ molar fraction $Y_{CO2}$ ($Y_{CO2} = p_{CO2} / p$, Eq. 4.) are therefore considered to represent the conditions that are likely to be encountered at, first, a producing well ($Y_{CO2} \sim 0.1$) and, second, an injecting well ($Y_{CO2} \sim 1.0$), respectively. Figure 6 compares the computed (layer 1) permeability changes for three different shrinkage/swelling coefficient ratios.

![Figure 6: Modelled permeability behaviour for three different $\alpha_{SCO2}/\alpha_{SCH4}$ ratios, layer 1 (Yellow seam), around a) a producing well and b) an injecting well. Results for the other two layers show similar trends.](image)

The results for $Y_{CO2} = 0.1$ (Figure 6a) indicate that the ratio $\alpha_{SCO2}/\alpha_{SCH4}$, within the range considered, has only a marginal influence on the permeability at a producing well (prior to significant CO$_2$ breakthrough). The permeability curves show that, as the pressure is reduced, the permeability at the producing well would rebound strongly after an initial decline, recovering its initial value at approximately 450 psi, and increasing to several times its initial value with further pressure drawdown, thus greatly enhancing the production rates.

On the other hand, CO$_2$ injection would cause a drastic fall in permeability around the wellbore (Figure 6b). Furthermore, the scale of permeability reduction is strongly influenced by the ratio $\alpha_{SCO2}/\alpha_{SCH4}$, rising from just over one order of magnitude to more than two orders of magnitude as $\alpha_{SCO2}/\alpha_{SCH4}$ is increased from unity to more than 1.2. The predicted scale of permeability reduction is consistent with the findings at Allison Unit. Injection/falloff tests performed in August 2001 at the four CO$_2$ injection wells, when they were shut-in, indicated that coal permeability around the injectors was $< 1$ md, a reduction of over two orders of magnitude [1].

**Injector Bottomhole-Pressure History Matching**

The gas-production rates (and CO$_2$-injection rates) were used as input to the simulator as complete records of the data are available for all the 16 producers and four injectors. Water rates and producing bottomhole-pressure data are mostly limited to the enhanced-recovery period. Complete records for the injector bottomhole pressures for the four injectors are also available. Presented as XY plots, all these data, together with other information such as the relative-permeability curves and produced gas compositions, were carefully digitized. The five producers in the central 5-spot pattern (Figure 4) were shut-in during the first six months of CO$_2$ injection. The four injectors were then shut-in for six months. After shut-in, substantial drops in the CO$_2$-injection rates were observed across the four injectors. An example is given in Figure 7 (where $p_{wf}$ refers to well flowing bottomhole pressure). It can be seen that the injection rate at well #141 dropped from an initial high of around 1,500 MSCF/D (thousand standard cubic feet per day) to between 800 and 900 MSCF/D following shut-in, a reduction of roughly 40% (Figure 7a).

The availability of both the injection rates and bottomhole-pressure data at the four injectors enabled the determination of $\alpha_{SCO2}/\alpha_{SCH4}$ in a relatively direct manner, through history matching the injecting bottomhole pressures. It was found that a ratio of 1.276 gives the best overall match for the four injectors. Recall in Figure 6 that such a swelling-coefficient ratio would result in an over two-orders-of-magnitude reduction in the layer-1 permeability. The history matching result for well #141 is presented in Figure 7b. The simulated injection bottomhole pressures show an excellent agreement with the field data, which remained roughly constant at 2,500 psi throughout the injection period, Figure 7b. For comparison, the mean layer-thickness-weighted wellblock pressure was computed and plotted in the same graph. It can be seen that weighted wellblock pressure continued to follow the
downward trend throughout the injection period, albeit at a gentler pace. The observed widening of the two pressure curves with time implies that an increasingly larger downhole pressure differential (~1,500 psi) was required to maintain the injection rates.

![Graph showing CO2 injection rate and bottomhole pressure](image1)

![Graph showing simulated vs. field bottomhole pressure](image2)

**Figure 7:** History matching of the producer bottomhole pressure.

The success in history matching the injector bottomhole pressures at well #141 has clearly demonstrated the validity of the permeability model used. It is worth pointing out that, as the magnitude of the swelling coefficient ratio $\alpha_{\text{SCO2}}/\alpha_{\text{SCH4}}$ (in the range 1 to 1.3) has been shown to have only marginal influence on the permeability behaviour at relatively low CO2 concentrations ($Y_{\text{CO2}} \sim 0.1$ or less), the deduction is made that the influence of $\alpha_{\text{SCO2}}/\alpha_{\text{SCH4}}$ is largely confined to a limited zone around the injectors before significant CO2 breakthrough occurs. This has been found to be the case in the current simulation study. Changes in the simulated gas-production rates, produced-gas composition and bottomhole pressures in the Allison pilot study area, within the simulation time period, were found to be marginal as $\alpha_{\text{SCO2}}/\alpha_{\text{SCH4}}$ was increased from 1 to 1.3.

**Simulation Results and Discussions**

Overall, a good agreement with the available field data was achieved in this simulation study. Significantly, the noticeable CO2 breakthrough observed at two of the producers within the 5-spot pattern, namely wells #113 and #120, and the produced-gas composition were fairly accurately predicted, Figure 8. The simulator performance in the prediction of producing bottomhole pressures varied and appeared to follow a trend, i.e. the greater the peak production rate, the closer the field data were to the model prediction for that well. Thus the best match to the field bottomhole pressures was achieved at well #119, which reached a peak rate of 7,000 MSCF/D, Figure 9. On the other hand, the bottomhole pressures for those wells with relatively low peak-gas production rates (< 2000 MSCF/D) were over-predicted by up to 200 psi. There are two possible reasons for this discrepancy: 1) the simplified reservoir model failed to take into account reservoir heterogeneities in permeability and layer thickness; 2) these wells were not well connected to the reservoir (as reflected in their relatively lower peak-gas rates), which was not accounted for in the model.

![Graph showing CH4 molar fraction](image3)

**Figure 8:** Simulated vs. field CO2 breakthrough and produced gas composition.
In Figure 9a, a dramatic increase in the gas-production rates was observed from mid-1998 to end of 1999, and this increase was closely correlated to the sharp fall in the (field) bottomhole pressure, from over 500 to below 100 psi, in the same period. This reservoir pressure-permeability correlation is consistent with the model prediction depicted in Figure 6a. There may also be another factor in action as a program of production-enhancement activities (such as re-cavitation) unrelated to the CO\textsubscript{2}-ECBM pilot was implemented shortly after the start of CO\textsubscript{2} injection [1]. The possible impacts of these activities on the absolute permeability were not explicitly taken into account during simulation, e.g. through skin factors as in [1], but rather lumped into the reservoir pressure effect. Figure 9b compares the resulting changes in the wellblock permeability for the three layers. It can be seen that the permeabilities in layers 1 and 2 increased sharply in this time period, up to four and three times the initial value (100 md) respectively. The considerable discrepancy observed in the permeability behaviour of the three layers is a manifestation of their different sorption characteristics (Table 1).

For the central well in the 5-spot pattern (#113, Figure 3), the simulated bottomhole pressure shows fairly good agreement with the limited field data available (Figure 10a). The excessively low pressures predicted in the last two years of the primary production are believed to be a relative-permeability effect. This was confirmed by comparing the predicted water rates with the field data, which showed an over prediction by 3 to 4 times in 1994 (Figure 10b). This means the effective gas permeability in the model would be much lower than it should be, thus leading to an unrealistic lower bottomhole pressure in the model in order to maintain the relatively high production rates (~ 2000 MSCF/D). In later years, the relative-permeability effects became insignificant, as water production was negligible compared to the gas rates. The over-prediction in the water rates may be attributed to the fact that the local variations in layer thickness and porosity were not reflected in the model.

CONCLUDING REMARKS

A reservoir simulator is an important tool for achieving a better understanding of the field reservoir processes during CO\textsubscript{2}-ECBM recovery. The Allison CO\textsubscript{2}-ECBM pilot, together with the detailed reservoir characterization
work carried out in a recently completed DOE sponsored research project [1], provides a unique database for benchmarking the performance of ECBM codes. In this study, we achieved a good overall agreement with the field data, in particular, the reported injecting bottomhole pressures, produced-gas composition at the two wells experiencing noticeable CO$_2$ breakthrough, and the producing bottomhole pressures were satisfactorily matched. The history-matching results in the injecting and producing bottomhole pressures and water-production rate, however, vary from well to well. The observed discrepancies may be partly attributed to the use of a simplified reservoir model, which neglects the reported reservoir heterogeneity in the net coal thickness, in situ permeability and porosity.

The outcomes of this study have clearly demonstrated the importance of using a dynamic permeability model in reservoir simulation of CO$_2$-ECBM. The validity of Shi and Durucan [3, 4] model for describing permeability changes in coalbeds under CO$_2$-ECBM conditions has been confirmed. In addition, the extended Langmuir sorption equations have also been proved to be adequate, at least within the context of this simulation effort, in modelling competitive desorption of methane in coalbeds.

REFERENCES