Modelling the uncertainty and risks associated with the design and life cycle of CO₂ storage in coalbed reservoirs

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Abstract

The main objective of the research reported in this paper was to address the uncertainties associated with coal seam reservoir performance during and after CO₂ injection in order to establish a methodology for the design, prediction and risk evaluation of safe and environmentally sound CO₂ storage in coal seam reservoirs. Full field scale simulations up to 1,000 years with over 140 permeability realisations and various swelling coefficients and sorption isotherms have shown that controlling the injection well bottomhole pressure ensures no overpressuring of the coalbeds or the caprock. Long-term leakage simulations with high cement deterioration and CO₂ leakage rates have shown that the likelihood of a leakage of 1% of the total volume of CO₂ stored over 1,000 years is low, and can be mitigated against through careful operational planning and reservoir management during CO₂-ECBM and CO₂ storage.

Keywords: CO₂ storage, coalbeds; uncertainty; risk assessment.

1. Introduction

The idea of storing CO₂ in geologic formations is rapidly gaining acceptance as one of the most promising options for reducing CO₂ emissions in the short term. While Carbon Capture and Storage (CCS) on its own cannot solve the climate change problem, it is a powerful addition to the portfolio of technologies needed to address climate change. The most recent update to earlier studies [1] shows that deep coals have 112 Gt of CO₂ storage capacity worldwide. Coal beds typically contain large amounts of methane-rich gas that is adsorbed onto the surface of the coal. The current practice for recovering coal bed methane is to depressurise the reservoir. Experimental research in the laboratory and field pilots at several coalfields in different parts of the world have demonstrated that CO₂ injection into coal seams has the potential to enhance CBM recovery with the added advantage that most of the injected CO₂ can be stored permanently in coal.

The concept of storing CO₂ in geologic formations as a safe and effective greenhouse gas mitigation option requires public and regulatory acceptance and the development of a framework for the management of such facilities. In this context it is important to develop a good understanding of the reservoir performance, uncertainties and risks that are associated with geological storage. The main objective of this research was to address the uncertainties associated with coal seam reservoir performance during and after CO₂ injection in order to establish a methodology for the design, prediction and risk evaluation of safe and environmentally sound CO₂ storage in coal seam reservoirs. The sources of uncertainty in risk assessment related to CO₂ storage in coal include:

- Measurement uncertainty and variability
- Model parameter uncertainty
- Modelling uncertainty
- Risk scenario uncertainty

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The majority of published work on geological storage risk assessment deal with conceptual and descriptive risk characterisation. However, decision makers need meaningful quantitative indicators, such as leakage rate and volumes and CO\textsubscript{2} concentration at a leakage site. Quantifying site-specific risks is not easy as there are uncertainties in almost all aspects of the project including reservoir characterisation, field operations, and particularly in assessing the future evolution of the storage site. This is why most CO\textsubscript{2} storage risk assessment studies conducted to date [2, 3, 4], including the probabilistic ones, are based on inference logic. The truly quantitative assessment of uncertainty and risk associated with CO\textsubscript{2} storage can only be achieved if the reservoir parameters and physical processes involved are used to quantify these risks. To date, relatively limited measurement data is available as compared to the data needs of the predictive models. The scarcity of data makes it even more important to use the available data in the most efficient way and to estimate the uncertainty associated with the model predictions. It is in this context that the stochastically based methodology developed in this project makes its contribution to the wide scale industrial implementation of CCS technology worldwide.

The first phase of this research, which was reported earlier at the GHGT-8 and later in an extended publication [5, 6], focused on the uncertainties related to the coalbed reservoir properties and their spatial distribution in detail and introduced the concept of model parameter uncertainty with some limited examples. This paper presents the results of the second phase of research carried out on the assessment of uncertainties associated with the coal seam reservoir performance and risk scenario uncertainty.

2. Assessment of the uncertainty related to the coalbed reservoir properties and their spatial distribution

The field data for the project was provided by the Alberta Research Council (ARC), Canada. The coal seams targeted in the study were the Mannville coals in Alberta. Digital well log data for 425 wells covering a surface area of approximately 2,500 km\textsuperscript{2} were provided by IHS Energy (Figure 1). The digital geological model, developed using seismic and well log data at a resolution of 250m grid, was provided by Natural Resources Canada. The coal strata were identified based on three logs, the gamma ray, neutron and the density [7, 8], and were confirmed using the geological model. Only 129 wells had these three logs in the formation of interest. These were further used for evaluating the reservoir properties of the seams. Coal density, thickness, total porosity and permeability were derived from the logs using procedures described by Mavor et al. [9] and Ellis et al. [10] and used during simulations. The two field permeability measurements taken from the ARC micro-pilot injection tests at two wells near the centre of the study area [11] were used to verify the permeabilities estimated. The in situ permeability of the seams encountered at each well was estimated using a relationship proposed by McKee et al. [12], which relates effective stress $\sigma$ [MPa] to permeability $K$ [md] ($10^{-15}$ m\textsuperscript{2}) as:

$$K = K_0 \exp(-3c_p \Delta \sigma)$$

(1)

where $c_p$ [MPa\textsuperscript{-1}] is the pore compressibility, $K_0$ [md] the permeability at a reference effective stress $\sigma_0$ [MPa], and $\Delta \sigma = \sigma - \sigma_0$. The porosity depth relationship used for the Mannville samples gave an average $c_p$ value of 0.203 MPa\textsuperscript{-1} which was within the range 0.194 and 0.271 reported for the US coal basins [12]. This value was adopted for estimating the permeabilities of each of the sampled coal seams. $K_0$ was estimated by plotting the two field measured permeability values (1.18 and 3.65 md) [11] against effective stress.

In order to generate permeability distributions rather than unique values, noise was added to the estimations. This was done by adding values drawn from a random normal distribution with mean 0 and standard deviation 200 to the effective stress variable. The new permeability distribution has a 5%ile value of 0.21 md, a median value of 1.72 md and a 95%ile value of 10.82 md. This is assumed to be an acceptable distribution of permeabilities given the values measured in the field and the distribution of porosities. Rather than assign fixed permeability values to each well sample, 20 distributions of permeability were generated. This was intended to prevent false patterns emerging from the future simulations.

For each well and coal seam, thickness, porosity and permeability distributions were generated. It was decided that on the basis of the data available it would be appropriate to prepare 2D simulations where the porosity and permeability values are averaged, weighted by the thickness of each seam. The new data were assessed spatially using the geostatistical software Isatis (Version 7). Sequential Gaussian Simulation (SGS) [13] was used to simulate 1,000 distributions of total porosity, permeability and total thickness across the entire (2,500 km\textsuperscript{2}) area. Due to the correlation between porosity and permeability (through their relationship with depth) the simulations were prepared jointly. An example each of the seam thickness, porosity and permeability maps obtained across the entire area are provided in Figure 1.

Since coal permeability has been recognised as the single most important parameter controlling gas productivity and CO\textsubscript{2} storage in a CBM field, it was decided to use the spatial model parameters to generate multiple realisations as inputs to the CO\textsubscript{2}-ECBM reservoir simulator and analyse the relative importance of these with regards to other significant model parameters, such as matrix shrinkage/swelling coefficient and Langmuir isotherm.
For the assessment of short term uncertainties the three stage pilot approach for field testing of ECBM production and CO₂ storage at the ARC test site proposed by Mavor et al. [14], involving a single well micro-pilot followed by a five-spot pilot and an expansion into a full-field pilot was considered. Different CO₂ storage scenarios were evaluated for primary CH₄ production and CO₂ injection periods ranging up to 30 years. As a first step in the development of the methodology, a typical ECBM five spot pattern of 500 x 500m (approximately 50 acres), located close to the ARC micro-pilots, was selected. A 20 x 20 cell single layer grid representing the target coal horizon was created. The SGS algorithm was used to generate 100 simulations of permeability and thickness on this new grid. The resulting total net thickness and permeability distributions were prepared for use in METSIM2, the Imperial College in-house ECBM simulator. The Langmuir constants used for CH₄ and CO₂ were the representative values reported by the ARC [11]. The key reservoir parameters used in this project were reported in the previous publications by the authors [5, 6]. The model was run for different realisations of the net seam thickness and permeability distributions, using a number of primary production and CO₂ injection scenarios where the production/injection time periods and/or the other reservoir properties such as the swelling coefficient were varied. These early simulations demonstrated the significance of shrinkage/swelling coefficient in terms of coal permeability and CO₂ injectivity. The volumes of CH₄ produced and CO₂ stored and were presented in previous publications by the authors [5, 6]. These early investigations enabled the authors to define the range of shrinkage/swelling coefficients and well spacing to be used in the full field scale assessments.

In the second phase of the project, a full scale CH₄ production-CO₂ injection scheme was used to assess the relative importance of the reservoir input data and simulator modelling uncertainty in different parts of the basin. An area of approximately 3.5 x 3.5Km (3,027 acres) with 36 CO₂ injectors and 49 CH₄ producers was selected (Figure 2). To test the sensitivity of the CO₂ volume stored to the spatially distributed permeability in the reservoir, a number of permeability realisations were generated over a 2D grid of 57 x 57 cells covering the model domain surrounding the two ARC micro-pilots. The permeabilities were obtained using conditional SGS and were constrained using the two measured permeabilities from the micro-pilots, the generated permeability distributions and the corresponding porosity values. In order to assess the sensitivity of the model results to permeability, the net thickness and porosity values for each grid cell were kept fixed. These were obtained by kriging over the grid, based on measurements made at wells located within the ranges of the respective variograms. Figure 2 presents three examples of the simulated permeability maps.
Figure 2. Injector and producer well configuration for the field scale tests and the three simulated realisations of permeability used in CBM/ECBM assessment.

(a) Number of simulations against coefficient of variation calculated for CO₂ volume stored and CH₄ produced.

(b) Histograms and cumulative density plots of net cumulative CO₂ volume stored and CH₄ produced.

c) Maps of pressure distribution for 10 selected permeability realisations.

d) Maps of CO₂ volume adsorbed for 10 selected permeability realisations.

Figure 3. Example reservoir simulation results at the end of 25 years injection period for the 3.5x3.5Km model domain.

In the runs presented here, the CH₄ production and CO₂ injection were designed for 5 years primary production from the 49 production wells. CH₄ production was facilitated by reducing the bottomhole pressure from the initial reservoir pressure of 7.66...
MPa (1,100 psi) to 0.69 MPa (1,100 psi) over the first year, which is then kept constant. CO₂ injection was scheduled to start at year 6 in all 36 injection wells. Based on the field micro-pilot experience an upper limit of 13.8 MPa (2,000 psi), which is approximately 6 MPa greater than the initial reservoir pressure, was set for the injection bottomhole to avoid fracturing the seam. During reservoir simulations, the produced gas composition at each production well was monitored to check for CO₂ breakthrough. A production well was shut-in if the CO₂ mole fraction of the produced gas stream exceeded 10%. The simulation terminated when shut-in occurred at 40 out of 49 wells, or after 10,950 days (30-year period). Simulations were generated until the coefficients of variation (CVs), calculated for CO₂ volume stored and CH₄ produced, were observed to stabilise (Figure 3a, Table 1). The final CO₂ volume stored was found to vary between 463 and 1,581x10⁶ m³ using the 140 different realisations of permeability, while CH₄ production varied between 337 and 513x10⁶ m³. The histograms of the two model outputs are provided in Figure 3b. Figures 3c and 3d show the pressure distribution and CO₂ volume adsorbed at the end of the 30 year period for 10 selected permeability realisations. These results emphasise the importance of the permeability as an input parameter. The CO₂ stored and CH₄ produced were found to be significantly positively correlated with the mean permeability across the grid (r ~ 0.85).

3. Assessment of the uncertainty related to the CO₂-ECBM reservoir simulator parameters

Under normal reservoir conditions, coal has a higher sorption capacity for CO₂ than that for methane, ranging from 2 to 10 times depending on rank [15]. Field CO₂-ECBM experience has shown that CO₂ adsorption in coal induces matrix swelling and up to two-orders of magnitude reduction in permeability [16, 17]. The dynamic permeability option included in METSIM2 [18] describes the swelling induced changes in the absolute permeability by an expression similar to Equation (1)

\[ K = K_0 \exp[-3c_j(\sigma - \sigma_0)] \]  

(2)

with

\[ \sigma - \sigma_0 = -\frac{\nu}{1-\nu}(p-p_0) + \frac{E}{3(1-\nu)} \sum_{j=1}^{2} \alpha_j (V_j - V_{j0}) \]  

(3)

In Equation (2) \( \sigma - \sigma_0 \) refers to the change in the effective horizontal stress, \( c_j \) [MPa⁻¹] is the cleat volume compressibility [19] and is equivalent to \( c_p \) in Equation (1). Equation (3) gives the change in effective horizontal stress as a function of reservoir pressure \( p \) [MPa] and the volume of adsorbed/desorbed gas for each gas component \( (V_j - V_{j0}) \) [std m³/m³] under laterally constrained reservoir conditions. \( E \) [MPa] and \( \nu \) [fraction] are Young’s Modulus and Poisson’s Ratio of the coalbed respectively, \( \alpha_j \) [m³/std m³] is defined as the matrix swelling/shrinkage coefficient. Equation (3) indicates that a decrease in permeability due to CO₂ injection is a function of both the swelling coefficient and the sorption characteristics (thus the shape of the adsorption isotherm) of coal.

METSIM2 was used to history match the micro-pilot test performed at one of the two ARC wells used in this project, from which a set of input parameters to the permeability model were obtained and used in the modelling work throughout the project, except for the swelling coefficient and the adsorption isotherm, which were varied in order to assess the overall model prediction uncertainty due to the choice of these parameters. Figure 4a illustrates the variation of field permeability and reservoir performance due to matrix shrinkage/swelling during primary CH₄ recovery and CO₂-ECBM for two shrinkage/swelling coefficients. The underlying cause for the stronger impact of swelling coefficient on permeability during CO₂-ECBM is the greater affinity of CO₂ to coal than methane. Figure 4b shows that for a given shrinkage/swelling coefficient, the effect of increased sorption capacity on permeability is not so pronounced. The sensitivity of the reservoir response to the swelling coefficient and sorption isotherm were tested using 10 permeability realisations. The CO₂ storage values for the 140 simulations were ranked and the permeability realisations corresponding to the min, max and intermediate 8 percentiles were retained. The maps of pressure and CO₂ stored at the end of the 30 year period for the simulations are those shown in Figures 3c, and 3d.

Figure 4. Changes in absolute permeability with shrinkage/swelling coefficient (a) and sorption capacity (b) during primary and CO₂-ECBM recovery and CO₂ storage.
For each selected permeability realisation, additional simulation runs were performed, by varying the swelling coefficients or Langmuir volume by +/- 10%. The results show that variations in sorption capacity for CH4 and CO2 yield opposite effects on CH4 production and CO2 storage (Figure 5). An increase in the Langmuir volume (case_VL1) would be favourable for methane production, but is undesirable from CO2 storage point of view, and vice versa (case_VL2). The results also indicate that the proportional variation in the Langmuir volume has a more pronounced impact on CO2 storage than on CH4 production.

The sensitivity of the results to the changes in the model parameters was quantified by calculating the CVs of the CO2 stored and CH4 produced. The 10 values of CO2 stored and CH4 produced obtained for the selected permeability realisations when increasing and decreasing the isotherm and swelling coefficient by 10% were first standardised by the original CO2 storage and CH4 production values to remove the variation due to the permeability. The results are presented in Table 1. It can be seen that the CO2 volume stored is slightly less sensitive to variation in the isotherm than the permeability and swelling coefficient. The CH4 produced is less sensitive in general to the model parameters, and in particular to the swelling coefficient.

Table 1. CVs calculated for model results after varying permeability, isotherm and swelling coefficient.

<table>
<thead>
<tr>
<th>Parameter Variation</th>
<th>CV based on CO2 stored</th>
<th>CV based on CH4 produced</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permeability 0.22</td>
<td>0.22</td>
<td>0.08</td>
</tr>
<tr>
<td>±10% isotherm</td>
<td>0.20</td>
<td>0.08</td>
</tr>
<tr>
<td>±10% swelling coeff.</td>
<td>0.22</td>
<td>0.02</td>
</tr>
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4. Risk scenario uncertainty modelling and assessment

The ultimate objective of risk assessment in CO2 storage was to generate reservoir simulations that would allow accurate predictions of future reservoir performance, including the use of the confidence intervals of these forecasts to establish risk scenario uncertainty. For the long term risks assessment, the scenarios considered were potential risks due to over pressurisation of the coal seam reservoir and well leakage due to deterioration of the cement seal. The injector well pressure during CO2 storage would normally be controlled in order not to fracture the coal. An injection bottomhole pressure of 13.8 MPa was used throughout and the maximum CO2 pressure in the reservoir was monitored in all the long-term simulations. It was observed that it was unlikely for the reservoir pressure to exceed the injection well pressure or the mechanical strength of the coal or the caprock. The probability of the seam pressure exceeding 10MPa in the full field scale reservoir is shown in Figure 6.

In order to assess CO2 leakage through sealed injection/production wells in the long term reservoir simulations, it is essential to set the physical leakage rates that may occur. It is recognised in the IPCC Special Report on CCS [20] that the estimation of physical leakage rates would require the development of new methodologies. Many containment risk assessments are benchmarked against an impact of 1% leakage of total gas stored over 1,000 years [21], therefore, the frequency and volume of potential leakage events were assessed for this time frame in this project.
Figure 6. Probability of the CO₂ storage pressure exceeding 10MPa.

Figure 7. (a, b) Gas leakage as a fraction of total gas stored in ten permeability realisations, (c) methane content in total gas leakage.

Although well-formed cement has a permeability of around $10^{-5}$ md leakage through abandoned wells can occur due to cement degradation. Scherer et al. [22] estimated that significant leakage may occur at cement permeabilities of $10^4$ md. These values were used as upper and lower limits of a lognormal cement permeability distribution, from which possible well cement permeabilities for the 85 wells on the full field model were randomly selected. The 85 permeability values obtained were then normalised to yield a set of relative permeabilities (with maximum value of 1).

In order to assign potential leakage rates to individual wells, the set of relative permeabilities defined was multiplied by a reservoir-pressure-dependent nominal rate to yield a leakage rate. In the simulation results presented below, a nominal leakage rate of 1 MSF/day (28.2 m³/day, or 10,000 m³/year) was used, which is equivalent to a maximum leakage rate of 1% over 1,000 years from a 1,000 million m³ CO₂ storage reservoir (Figure 7a). It was further assumed that this nominal rate would be achieved if the reservoir pressure reaches 8 MPa, just above the initial reservoir pressure. Post methane production/CO₂ injection leakage simulations presented here for clarity were carried out on the same 10 permeability realisations used for the sensitivity study described above. The results show that the overall gas leakage volume at 200 years varies from 0.18 to 0.28 % of the total gas-in-place at the end of CO₂ injection period for each permeability realisation. Figures 7a and b show that the gas leakage rate starts to stabilise after year 100. Assuming no mitigation action, the total leakage after 1,000 years (as a fraction of the initially stored CO₂) for the ten simulations was estimated at between 0.94 and 1.12% [23]. The long term leakage volumes thus obtained represent the maximum potential leakage at high well cement deterioration and well leakage rates, as the rates would reduce slightly with time as the reservoir pressure itself edges downward.

As well as total gas leakage rate, the composition of the gas is also of interest. The results for the 10 simulation runs suggest that the leaked gas would progressively become richer in CH₄ with time, accounting for between 15 and 20 percent of leaked gas over the 1,000 year period, except for one realisation (run 9), where the CH₄ content is substantially higher due to the relatively low amount of CO₂ originally stored (Figure 7c).

5. Conclusions

Coalbed permeability is the most important reservoir property controlling primary methane production as well as enhanced recovery and CO₂ storage. Research has shown that in high swelling coefficient coal seams only a very limited volume of CO₂ could be stored due to the effects of CO₂ induced matrix swelling on coalbed permeability and thus CO₂ injectivity. On the other hand, halving the matrix swelling coefficients results in an improvement of more than one order of magnitude in permeability and CO₂ storage, demonstrating the significance of swelling coefficient in CO₂ enhanced coalbed methane recovery and CO₂ storage. The impact of matrix swelling coefficient on CH₄ production rates, however, is mixed. While a lower swelling/shrinkage coefficient would favour CO₂ storage, it is less desirable for primary recovery as matrix shrinkage has a positive effect on coalbed permeability.
For a given shrinkage/swelling coefficient, the effect of increased sorption capacity on permeability is not so pronounced. The results have shown that an increase in the Langmuir volume would be favourable for methane production, but is undesirable from CO2 storage point of view, and vice versa. The results also indicate that the CO2 volume stored is slightly less sensitive to variations in the sorption isotherm than the permeability and swelling coefficient. The CH4 produced is less sensitive in general to the model parameters, and in particular to the swelling coefficient.

Full field scale simulations up to 1,000 years with over 140 permeability realisations and various swelling coefficients and sorption isotherms have shown that controlling the injection well bottomhole pressure ensures no overpressuring of the coalbeds or the caprock. Long-term leakage simulations with high cement deterioration and CO2 leakage rates have shown that the likelihood of a leakage of 1% of the total volume of CO2 stored over 1,000 years is low, and can be mitigated against through careful operational planning and reservoir management during CO2-ECBM and CO2 storage.

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