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CRADA FINAL REPORT

Carbon Dioxide Sequestration in Geologic Coal Formations

Idaho National Laboratory

and

BP Corporation North America, Inc. (formerly Amoco Production Company, then BP America Production Company)

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Abstract

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Partner: BP Corporation North America, Inc. (formerly Amoco Production Company, then BP America Production Company)

Title : Carbon Dioxide Sequestration in Geologic Coal Formations

BP Corporation North America, Inc. (BP) currently operates a nitrogen enhanced recovery project for coal bed methane at the Tiffany Field in the San Juan Basin, Colorado. The project is the largest and most significant of its kind wherein gas is injected into a coal seam to recover methane by competitive adsorption and stripping. The Idaho National Engineering & Environmental Laboratory (INEEL) and BP both recognize that this process also holds significant promise for the sequestration of carbon dioxide, a greenhouse gas, while economically enhancing the recovery of methane from coal. BP proposes to conduct a CO2 injection pilot at the Tiffany Field to assess CO2 sequestration potential in coal. For its part the INEEL will analyze information from this pilot with the intent to define the CO2 sequestration capacity of coal and its ultimate role in ameliorating the adverse effects of global warming on the nation and the world.

Carbon Dioxide Sequestration in Geologic Coal Formations

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ABSTRACT

The objective of this project is to develop mechanistic models specific to CO_2 sequestration in BP's Tiffany coal bed methane (CBM) field. In this study, the original field model was modified to match the field performance of a 5-spot pattern in the northern part of the Tiffany Field where BP plans to perform a micro-pilot test. The modified model consists of one high-permeability fast layer sandwiched between two low-permeability slow layers. In this mechanistic model, the fast layer represents well-cleated and fractured coal from all geological layers while the slow layers represent coal with little or no fracture development from the same geological layers.

The model successfully matched the performance of the 5-spot pattern during the enhanced recovery period (N_2 injection). However, in order to match nitrogen breakthrough times and nitrogen cut the vertical transmissibility between layers had to be set to zero. During gas injection, nitrogen was allowed to enter all three layers, not just the high-permeability fast layer. However, because the permeabilities of the slow layers were low and there is no communication between the fast and the slow layers, most of the injected nitrogen entered the high-permeability fast layer. This suggests that the future gas injection and CO_2 sequestration may be restricted to only one third of the total available pay.

For future gas injections, the modified model predicted early CO_2 breakthrough with high CO_2 cut. This suggests that the actual CO_2 sequestration capability of the Tiffany Field might not be as high as originally expected. This is a direct consequence of the reduced available pay in the modified model. The modified model also predicted early inert gas (N_2 plus CO_2) breakthrough and high inert gas cut during future gas injections. If this is confirmed in the pilot test, the high volume of inert gas produced could overwhelm the reprocessing capability resulting in early termination of the project.

INTRODUCTION

There is a growing consensus in the international community that CO_2 emissions from burning fossil fuels play an important role in global climate change. Despite the recent controversy of who should bear the most burdens in reducing the CO_2 emission, it is inevitable that deep cuts in CO_2 emission will be required in the near future. Recent efforts in reducing the carbon content in fuels and improving the energy efficiency can certainly help in reducing the amount of CO_2 released into the atmosphere. However, large-scale carbon sequestration will definitely be required to achieve the targeted atmospheric CO_2 level of 550 ppm by 2025.

Of the sequestration options available, geologic sequestration of CO_2 in coal formations is considered one of the methods with the greatest short-term potential. Coal beds typically contain a large amount of methane-rich gas that is adsorbed onto the surface of the coal. Tests have shown that CO_2 is roughly twice as adsorbing on coal as methane, giving it the potential to efficiently displace methane and remain sequestered in the bed. Enhanced recovery of coal bed methane (CBM) by CO_2 injection has been demonstrated in limited field tests, but much more work is necessary to understand and optimize the process. Work is also needed to develop better estimates of the potential capacity of cost-effective coal bed sequestration in the United States.

To date, only one commercial demonstration of enhanced methane recovery by gas injection has been implemented. This is BP's Tiffany project in the San Juan Basin, Colorado. The Tiffany

Field consists of 38 producer and 10 injector wells. The current Tiffany field model incorporates the full geologic description. The description consists of five coal layers, some of which do not extend throughout the unit. Coal continuity and thickness are greatest in the northern portion of the field. The model provided good historical matches of the field performance during the primary production period. During the subsequent enhanced recovery phase, N_2 was injected into the field to accelerate methane recovery. The field model was proven inadequate in many aspects to accurately match field performance during the enhanced recovery phase. Most importantly, it failed to predict nitrogen breakthrough times and nitrogen cut responses at the majority of the responding producers. The actual N_2 breakthrough times were much earlier than that predicted by the field model. For the field model to better match the N_2 breakthrough times and N_2 cut responses, the nitrogen injection would have to be restricted into one geological layer, which accounts for only 25% of the total pay. However, this would violate production-log data from the injectors, which showed nearly uniform injection into most perforated intervals. With BP's proposal to supplement the nitrogen injection with the CO_2 captured from it gas processing plant, it is vital that the field model be modified to reflect the actual field performance during gas injection so that the reservoir's true potential for enhanced recovery and CO_2 sequestration can be determined. The objective of this project is to develop mechanistic models specific to CO_2 sequestration in BP's Tiffany coal bed methane (CBM) field.

RESERVOIR PERFORMANCE MODELING

The validity of a particular model description will be determined from its ability to predict injected gas breakthrough times, cumulative production (methane, nitrogen, and carbon dioxide), and methane cut. The desired outcome of the process is an estimate of actual CO_2 sequestration capability and project lifetime, which is in part dictated by the CO_2 breakthrough time and the CO_2 production cut with time. (The amount of CO_2 reprocessed will determine the economic limit for the project.)

In this report, we focus on a five-spot pattern in the northern part of the field where BP plans to conduct a micro-pilot test in the near future. Fig. 1 shows that the pattern consists of one in-pattern and three off-pattern injectors as well as four in-pattern and one off-pattern producers. Results from the micro-pilot tests will be used to validate and improve the regional model. The ultimate objective is to develop a full-field model for CO_2 sequestration in the Tiffany Field.

Model Description. To match the field performance during the enhanced recovery phase, we assumed that the high permeability streaks or conduits such as fractured and well-cleated coal within each geologic layer contributed to the early nitrogen breakthrough. Although the high permeability pay dominates early production response, the long-term response is in large part dictated by the amount of gas exchanged between high and low permeability packages. Instead of dividing each geologic layer into a fast and a slow component, we modified the model to include a high-permeability fast layer sandwiched between two low-permeability slow layers. In this mechanistic model, the fast layer represents well-cleated and fractured coal from all geological layers while the slow layers represent coal with little or no fracture development from the same geological layers. Also, the horizontal permeability (k_h) in every grid block was rotated 45° counter clockwise to match the field permeability trend (north-south) in the simulation area.

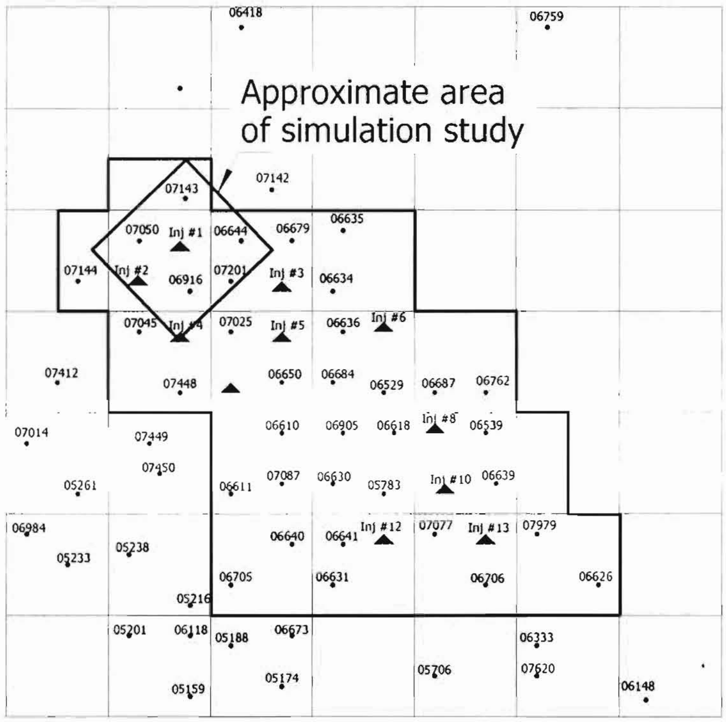

Fig. 1. 5-spot pattern area of the simulation study.

History Matching. During history matching, layer thickness and permeability were adjusted to control gas breakthrough. Vertical transmissibility between layers was manipulated to match late time response. Fig. 2 shows that the modified model matched the nitrogen breakthrough times and nitrogen cut reasonably well for all in-pattern producers. As shown in Fig. 3, the model also did a good job matching the total gas production for all in-pattern producers. However, in order to match nitrogen breakthrough times and nitrogen cut, the vertical transmissibility had to be set to zero. This means that there was no communication between the fast and the slow layers. In this model, nitrogen was allowed to enter all three layers, not just the high-permeability fast layer. However, because the permeabilities of the slow layers were low and there is no communication between the fast and the slow layers, most of the injected nitrogen entered the high-permeability fast layer. Figs. 4, 5, 6 show the nitrogen saturations at the end of the nitrogen injection for the high-permeability fast layer (Layer 2) and the two low-permeability slow layers (Layers 1 and 3), respectively. From Fig. 4, we can clearly see the preferred permeability trends between the injectors and the producers. A comparison between Fig. 4 and Figs. 5, 6 shows that at the end of the nitrogen injection, the nitrogen saturations were very high in the fast layer (Layer 2) and very low in the slow layers (Layers 1 and 3). This implies that the nitrogen injection and enhanced methane recovery were mostly restricted to only about one third of the available pay. The impact of this on the recoverable reserves and ultimately the sequestration capacity of the reservoir will be discussed in the next section.

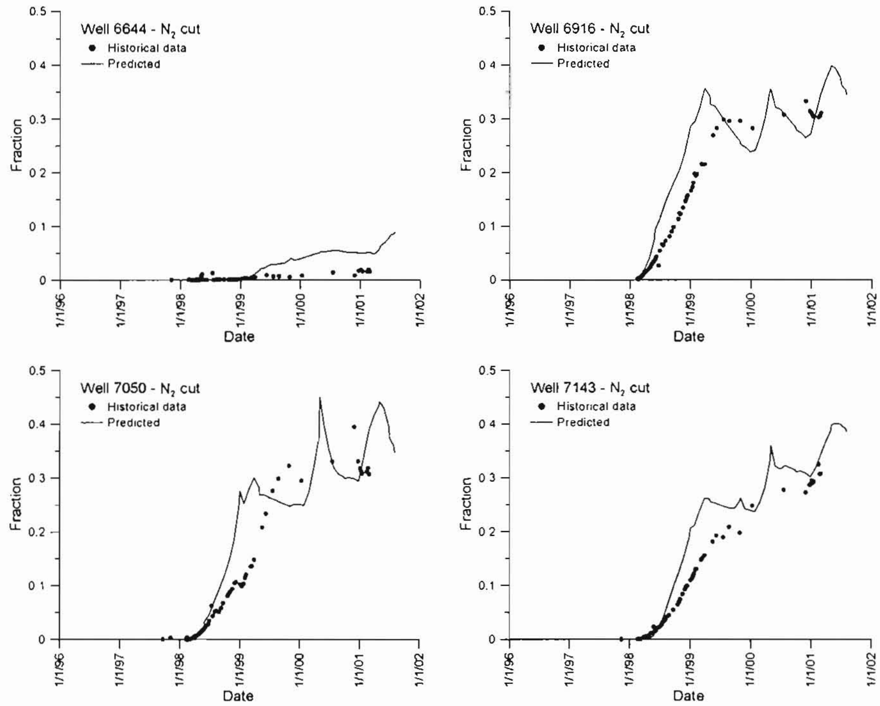

Fig. 2. Nitrogen production cut.

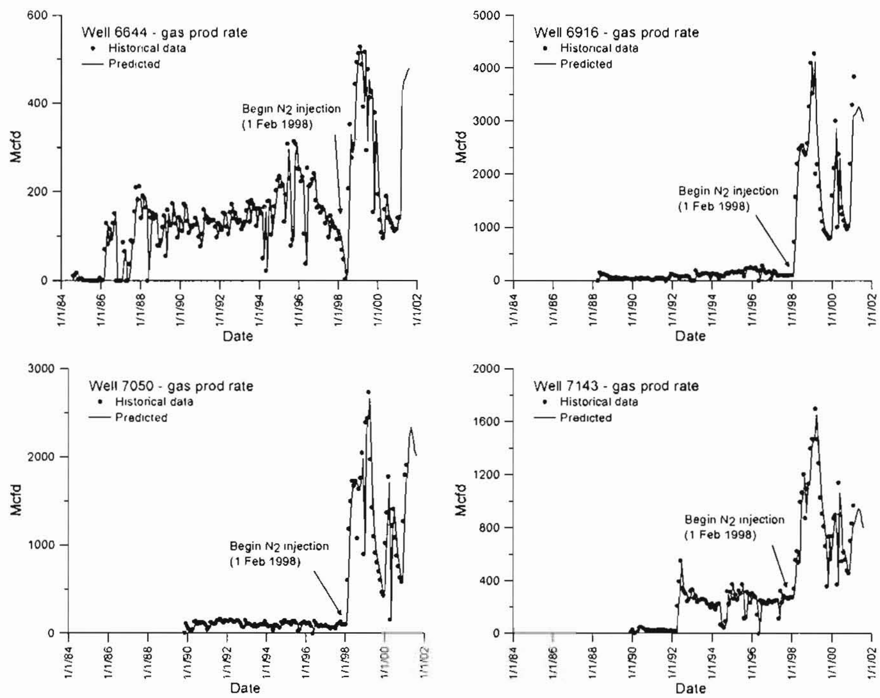

Fig. 3. Total gas production rate.

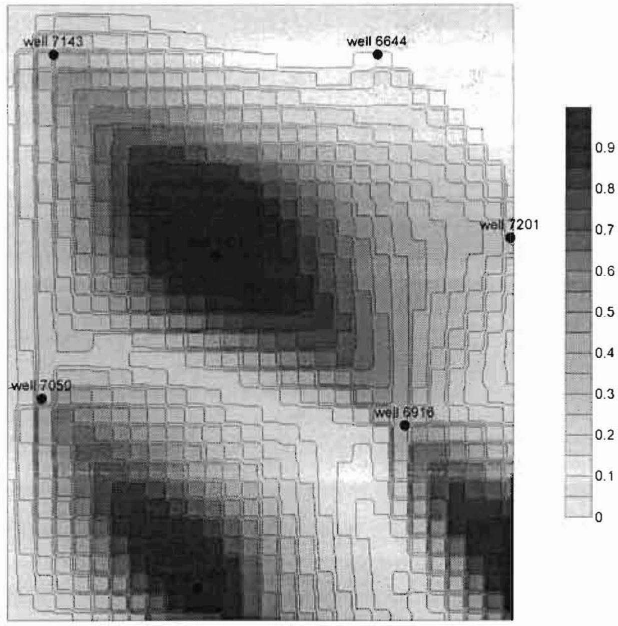

Fig. 4. N_2 saturations at the end of history matching (Layer 2).

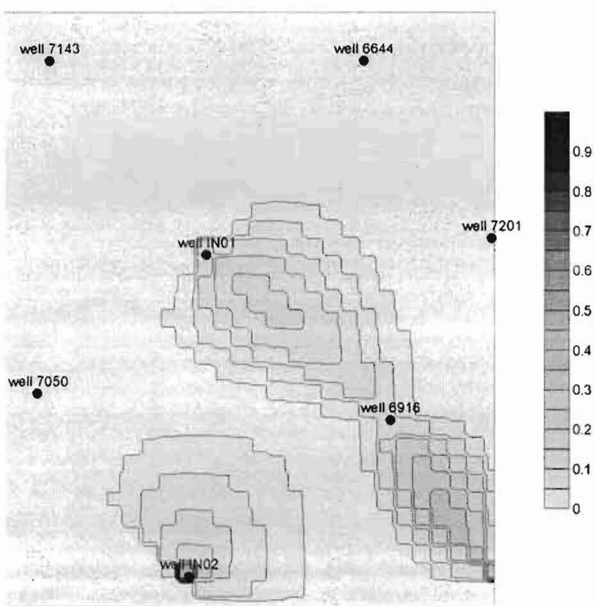

Fig. 5. N_2 saturations at the end of. history matching (Layer 1).

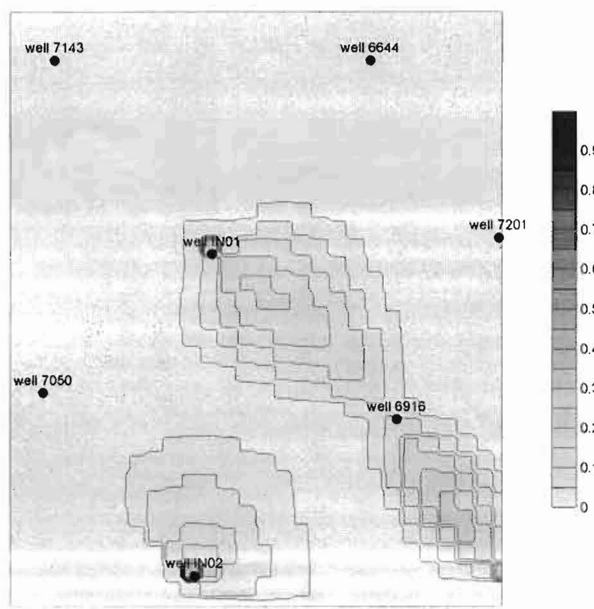

Fig. 6. N_2 saturations at the end of history matching (Layer 3).

Fig. 7 shows that the modified model did a reasonable job matching the bottomhole flowing pressures of all in-pattern producers during the enhanced recovery phase. However, it overestimated the bottomhole flowing pressures during the primary production period for all but one producer. As shown in Fig. 7, the modified model matched the pressure responses of Well 6644 reasonably well during both the primary and the enhanced recovery phases. Fig. 4 shows that unlike other producers, this well is not linked to any injector on the preferred permeability trends in the simulation area. In other words, the well is least affected by the pressure increase during the gas injection. These findings suggest that the coal formation along the preferred permeability trends in the simulation area reacted differently to pressure depletion during the primary production period and gas injection during the enhanced recovery phase. During nitrogen injection, the elevated pressure caused coal fractures along the preferred permeability trends not only to expand but also to extend from injectors to producers. Even in the low-pressure regions near the producers, the permeabilities were higher than expected. This permeability enhancement may be additionally supported by matrix shrinkage caused by a lower equilibrium adsorbed nitrogen concentration (phase volume) versus methane. One possible way to satisfactory simulate both the primary and enhanced recovery phases is to apply negative skin factors to wells on the preferred permeability trends during nitrogen injection but not during the primary production period. Another way is to use one stress-permeability relationship during primary production and a different one during enhanced recovery with gas injection. Also, different stress-permeability relationships might be required for different injector/producer pairs with different degrees of connectivity. Unfortunately, the simulator that we are using right now does not have this capability. Since the modified model is based on field performance during the enhanced recovery phase with N_2 injection, it should be adequate in predicting the field performance during the subsequent CO_2 and N_2 injections.

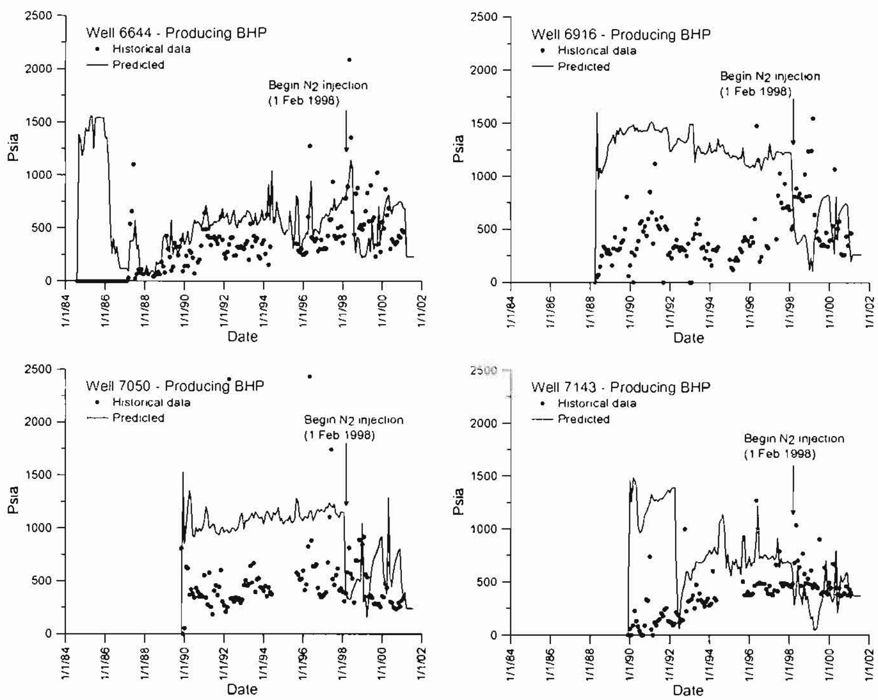

Fig. 7. Bottomhole flowing pressure.

MODEL PREDICTIONS

The important factors that control the project lifetime and actual CO_2 sequestration capability are the inert gas (CO_2 and N_2) production and the inert gas cut with time. While methane production represents the income potential, it is the amount of inert gas reprocessed that actually determines the economic limit for a CO_2 sequestration project. In this report, we explored three different injection scenarios to study their effects on inert gas production and inert gas cut. In the first scenario, we simulated a continuous injection of pure CO_2. In the second scenario, we simulated a continuous injection of a mixture of 76% N_2 and 24% CO_2. In the third scenario, we took into account the seasonal fluctuation of the nitrogen processing capability at Tiffany Field. In this case, we alternated the injection between the N_2-CO_2 mixture (Nov. through April) and pure CO_2 (May through Oct.). In all three scenarios, the simulation of future injections ran from 01/01/2002 to 01/01/2020. The total volume of gas injected is constant between scenarios.

Daily CO_2 Production Rate and CO_2 Cut. Figs. 8 and 9 summarize the daily CO_2 production rate and the CO_2 cut with time for the entire 5-spot pattern (excluding well 7201), respectively. Fig. 9 shows that the CO_2 breakthrough occurred within one year after the injection began. After breakthrough, the daily CO_2 production rate for all three gas-injection scenarios increased continuously until the end of simulation period. Fig. 8 also shows that the increase in daily CO_2 production rate was most significant for the case of continuous CO_2 injection. The CO_2 cut shown in Fig. 9 basically followed the similar trend. For the case of continuous CO_2 injection, the CO_2 production cut increased quickly after breakthrough reaching 50% in less than 5 years. The increase was however, less dramatic for the other two gas-injection scenarios.

The important message here is that the modified model predicted early CO_2 breakthrough with high CO_2 cut during future gas injections. This suggests that the actual CO_2 sequestration capability of the Tiffany Field might not be as high as originally expected. This is a direct consequence of the reduction of the available pay in the modified model.

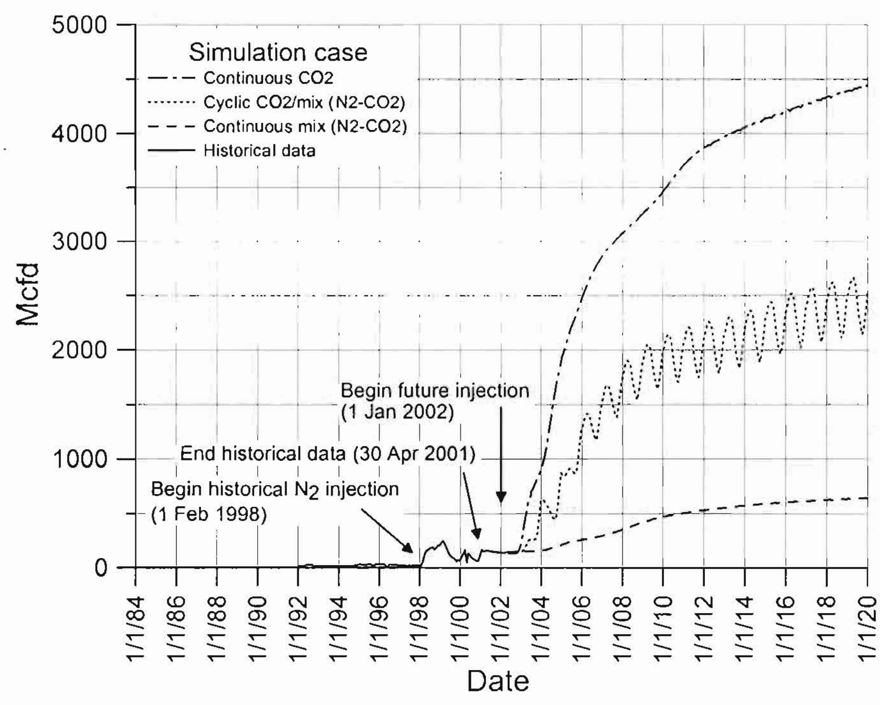

Fig. 8. Daily total CO_2 production (excluding Well 7201).

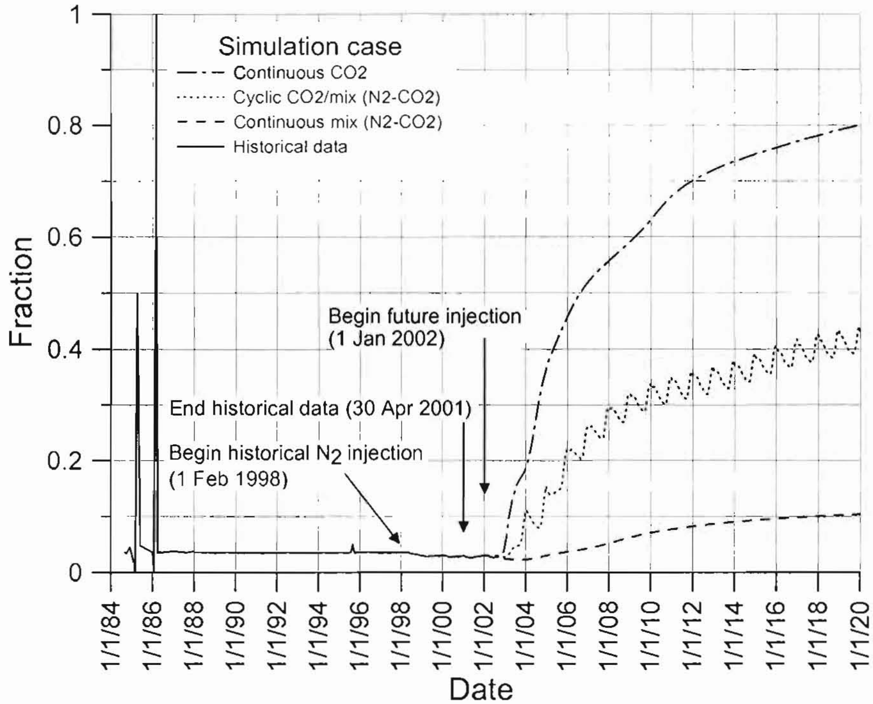

Fig. 9. Daily total CO_2 cut (excluding Well 7201).

Daily Total Inert Gas Production Rate and Inert Gas Cut. The amount of daily inert gas production that on-site facilities can handle is a limiting factor that determines the economic limit for a CO_2 sequestration project. Figs. 10 and 11 show that for all three gas-injection scenarios, both the daily total inert gas (N_2 plus CO_2) production and the inert gas cut rose quickly after the gas-injection began. Fig. 11 shows that for the cyclic CO_2/N2-CO_2 and continuous N2-CO_2 cases, the inert gas cut reached 50% in less than 2 years. The case of continuous CO_2 injection however, showed a two-year delay in inert gas breakthrough (Fig. 10). Also, in this case, the inert gas cut did not reach 50% until 4 years into the gas injection (Fig. 11). This delay in inert gas breakthrough was caused by CO_2 being twice as adsorbing on coal than methane.

The simulation results demonstrate that without adequate inert gas reprocessing capability, the predicted early breakthrough of inert gas and high inert gas cut can severely shorten the project lifetime and further limits the CO_2 sequestration capability of the Tiffany Field.

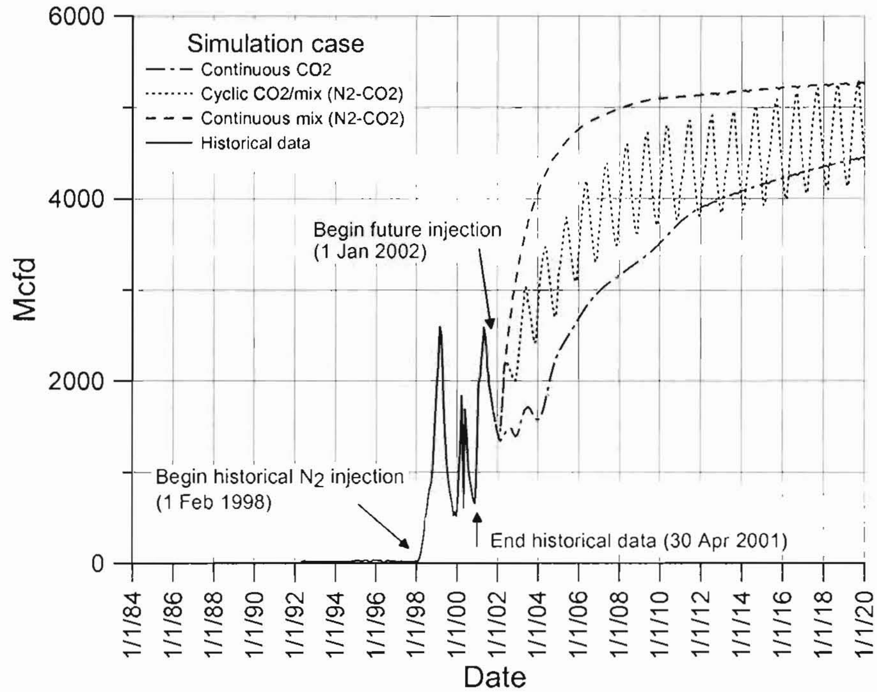

Fig. 10. Daily total inert gas production (excluding Well 7201).

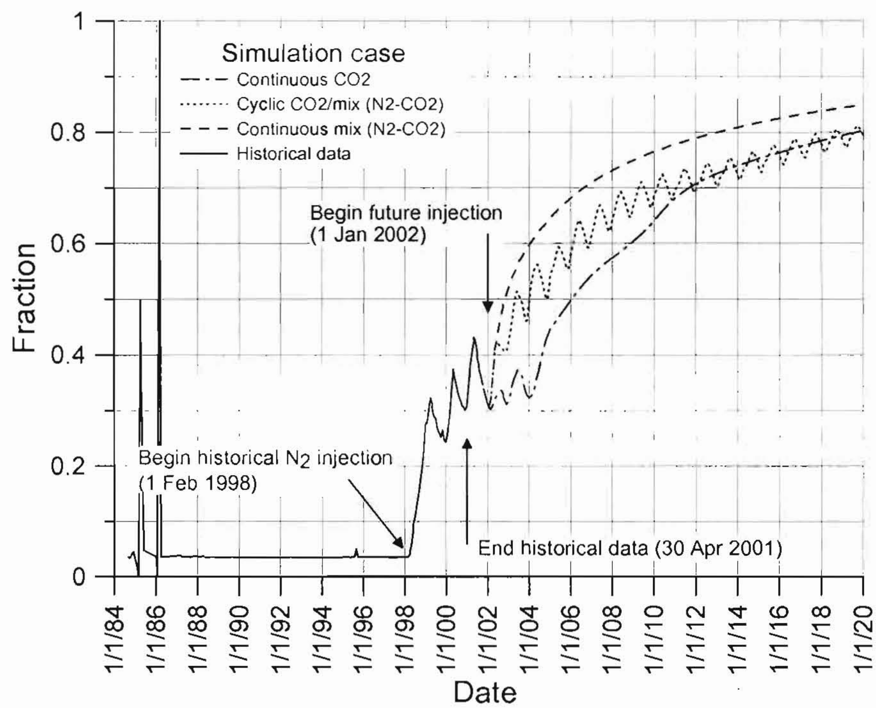

Fig. 11. Daily total inert gas cut (excluding Well 7201).

Methane Production. Fig. 12 shows that the methane production followed a gradual decline trend during the gas-injection period. For the case of continuous CO_2 injection, the methane production showed an initial jump and then followed basically the same decline trend as in other gas-injection scenarios. Fig. 13 shows that the cumulative amount of methane recovered during the gas-injection period was proportional to the CO_2 content in the injection gas. (The higher the CO_2 content in the injection gas, the higher the methane recovery.) This is consistent with the theory that CO_2 is more efficient in displacing methane from coal formation.

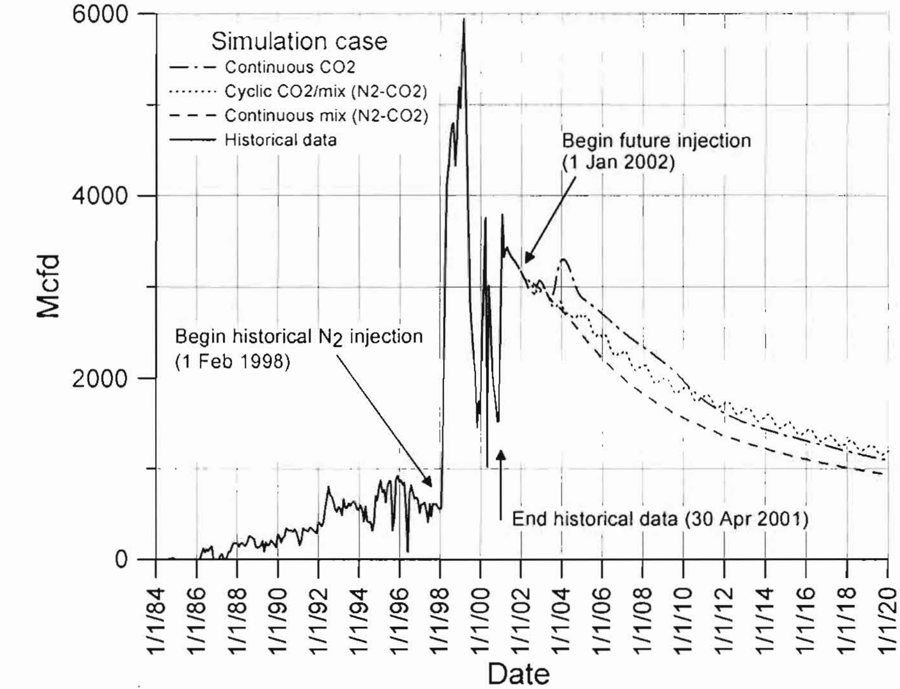

Fig. 12. Daily total methane production (excluding Well 7201).

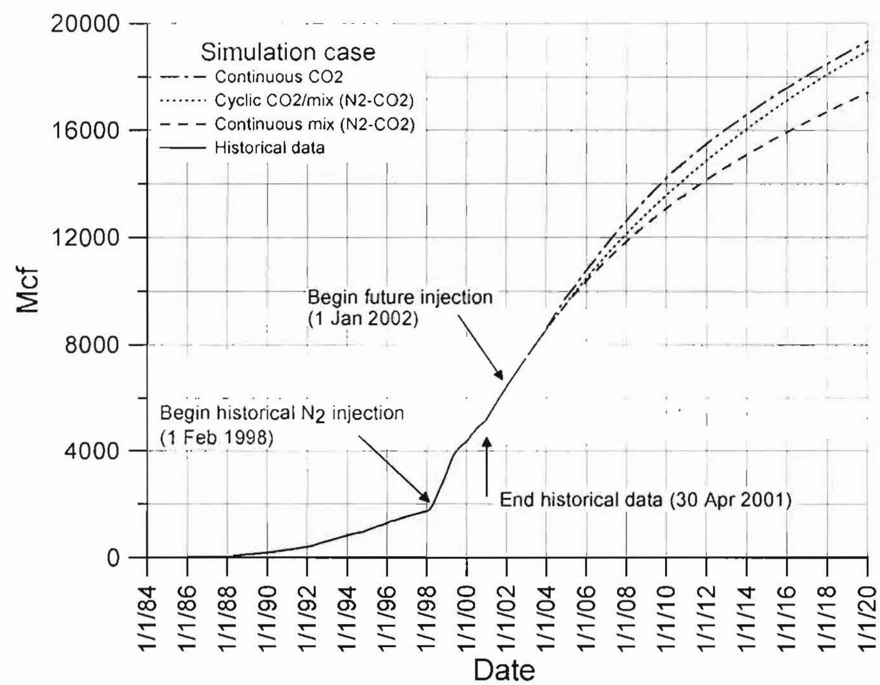

Fig. 13. Total cumulative methane production (excluding Well 7201).

SUMMARY

1. A modified field model was developed to match the field performance of a 5-spot pattern in the northern part of the Tiffany Field where BP plans to perform a micro-pilot test.
2. The modified model consists of one high-permeability fast layer sandwiched between two low-permeability slow layers. In this mechanistic model, the fast layer represents well-cleated and fractured coal from all geological layers while the slow layers represent coal with little or no fracture development from the same geological layers.
3. The model successfully matched the performance of the 5-spot pattern during the enhanced recovery period (N_2 injection). However, in order to match nitrogen breakthrough times and nitrogen cut the vertical transmissibility had to be set to zero. During gas injection, nitrogen was allowed to enter all three layers, not just the high-permeability fast layer. However, because the permeabilities of the slow layers were low and there is no communication between the fast and the slow layers, most of the injected nitrogen entered the high-permeability fast layer. This suggests that the future gas injection and CO_2 sequestration may be restricted to only one third of the total available pay.
4. During nitrogen injection, the elevated pressure caused the coal fractures on the preferred permeability trends not only to expand but also to extend from injectors to producers. Even in the low-pressure regions near the producers, the permeabilities were higher than expected.
5. The modified model predicted early CO_2 breakthrough with high CO_2 cut during future gas injections. This suggests that the actual CO_2 sequestration capability of the Tiffany Field might not be as high as originally expected. This is a direct consequence of the reduction of the available pay in the modified model.
6. The modified model also predicted early inert gas (N_2 plus CO_2) breakthrough and high inert gas cut during future gas injections. The high volume of inert gas produced could overwhelm the reprocessing capability resulting in early termination of the project.

FUTURE WORK

More work is under way to estimate the CO_2 sequestration potential of the micro-pilot area by sequentially shutting in the producers when a certain limit on the inert gas cut is reached. The amount of CO_2 sequestered after all the producers are shut in and the field reaches it discovery pressure will be calculated. The results will be used as a baseline to determine the true CO_2 sequestration capability of the Tiffany Field.

Results from BP's micro-pilot test will be used to validate and improve the modified model. The ultimate objective is to develop mechanistic models specific to CO_2 sequestration in BP's Tiffany coal bed methane (CBM) field.