FIELD-TESTING CO_2 SEQUESTRATION AND ENHANCED COALBED METHANE RECOVERY IN ALBERTA, CANADA – A HISTORICAL PERSPECTIVE AND FUTURE PLANS

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ABSTRACT

The Alberta Research Council is leading a program on the reduction of greenhouse gas emissions by injecting CO_2, N_2, and flue gas in a deep coal seam while enhancing the recovery factors and production rates of methane. A field test was carried out in 1998 to obtain accurate information on CO_2 storage and production of CH_4 following a CO_2 injection/soak period. Experimental data was used to calibrate simulation models for a feasibility analysis of a full-scale, 5-spot pilot study planned for 2000-2002. In late 1999, a new well was drilled and completed in order to perform a simulated flue gas micro-pilot test into the coal seam. Three additional well may be drilled in 2001. Subsequently, gases will be injected into the four wells and production will be monitored from a fifth well over a 12-month period. Full-scale commercial development could begin as early as 2003.

KEYWORDS: Coalbed methane recovery, CO_2 storage, Alberta Basin

INTRODUCTION

The coalbed methane (CBM) recoverable resources in the Plains and Foothills regions of the Western Canada Sedimentary Basin (WCSB) are estimated to be 135 to 261 trillion cubic feet (TCF) and are comparable to the marketable conventional gas endowment of 263 TCF (1). About 48.5 megatonnes (Mt) or 32% of the 151 Mt of CO_2 emissions generated in Alberta in 1996 originated from coal-fired power plants (Figure 1). The above figure also shows that coal beds in the Alberta part of the WCSB are second only to aquifers in terms of storage capacity for CO_2 (2). An abundance of deep and unminable coal seams in Alberta makes geological storage of CO_2 applicable, particularly in those areas located in close proximity to power plants emitting large quantities of CO_2, a greenhouse gas (GHG). In such a storage process, the CO_2 produced from the power plants could be injected into the coal seams to produce CBM. This could lead to null-GHG power plants that would be fuelled by methane released from the deep coals in a cyclical approach that would eliminate any release of CO_2 to the atmosphere.

The Alberta Research Council is currently leading a multi-phase study on field-testing CO_2-enhanced CBM recovery at a site near Fenn Big Valley, Alberta, Canada. Phase I encompassed a paper study of the initial assessment and proof of concept of injecting CO_2, nitrogen, and flue gas into Mannville Group coals (Lower Cretaceous age) in the Alberta Basin. Phase II concentrated on the design and implementation of a CO_2- micro-pilot test following procedures developed by Amoco Production Company for coals in the San Juan Basin in the U.S. The project is now in Phase III, which is to evaluate the design and implementation of a full-scale pilot project. Burlington Resources has successfully injected CO_2 into relatively high permeability coal seams in the San Juan Basin and stimulated CBM production and recovery rates compared to primary production (a pressure depletion process). Additional tests are needed to demonstrate the concept for the low permeability coals of the Alberta Basin and elsewhere in the world.

RESULTS AND DISCUSSION

Following the successful completion of Phase I in the summer of 1997, Phase II proceeded in a timely manner and was completed in the spring of 1999. The primary goals of Phase II were the following: (1) to accurately measure data from a single well test involving a series of CO_2 injection/soak cycles followed by production of CO_2 and methane; (2) to history match the measured data with a comprehensive coal gas reservoir simulation model in order to obtain estimates of reservoir properties and sorption characteristics; and (3) to calibrate simulation models to predict the behaviour of a large-scale pilot project or full field development. The field test was carried out in an existing Gulf Canada well at the Fenn Big Valley location in the central Alberta Plains. Phase II was, in essence, the prelude to a full-scale 5-spot pilot test. The study concluded that a full-scale pilot CO_2 sequestration/ECBM (enhanced coalbed methane recovery) project is possible in the above location (3).

The economic feasibility analysis of Phase II revealed that flue gas injection offers better economic return than pure CO_2 injection unless there is credit for the CO_2 avoided. At a rate of US$1.00 per thousand standard cubic feet (MSCF) of CO_2 (US$19 per tonne), the CO_2 would account for US$2.00 per MSCF of methane sold, assuming that it takes at least 2 cubic feet of CO_2 injected for each cubic feet of methane produced. The CO_2-ECBM recovery mechanism is shown in Figure 2 (4-5). It might be advantageous to optimize the CO_2/N_2 composition of the flue gas when considering CO_2 storage/sequestration options. If flue gas is injected, the CO_2 would remain sorbed in the coal matrix while the majority of N_2, by being adsorbed less than CO_2, would be produced along with the methane. Flue gas injection would enhance CBM production rates by more than a factor of two (6). However, the early breakthrough of N_2 at the production well will cause an additional expense of having to separate N_2 from methane for sales. Pressure swing adsorption (PSA) systems are the optimum method to remove N_2 from the produced gas for small-scale/large N_2 content operations whereas cryogenic processes are favored for large field operations (7). Flue gas conditioning, compression, and N_2/CH_4 separation in surface facilities remain some of the technical challenges that will be addressed in Phase III.

Therefore, by combining CO_2 and N_2 for injection, the appearance of N_2 will be retarded compared to a pure N_2 injection stream and the methane production rate will be enhanced compared to a pure CO_2 stream [6]. However, gas separation will play a key role in the production of methane from coal beds and the most economic gas separation method for the injection gas stream will depend on the specified CO_2 concentration of this stream (7).

The three numerical models that were evaluated in Phase II adequately predicted the primary production of CBM. One such simulation, based on a 5-spot, 320-acre pattern, showed that CH_4 production rate increased by a factor of about 5 compared to primary production when flue gas was injected but methane production decreased rapidly (Figure 3). On the other hand, pure CO_2 injection resulted in methane production at lower rates but for much longer periods of time. Only one out of the three models evaluated was suitable to simulate flue gas injection. None of the three simulation software packages were capable of predicting the produced gas composition in the field test with any degree of accuracy. A better understanding of the process mechanisms involved, for example multiple gas sorption and diffusion, and changes in coal matrix volume due to sorption/desorption of gases is needed to guide any future development of the models.

Phase III was divided in two parts, to be conducted in stages from 1999 to 2001. Phase III-A evaluated the options for the treatment of flue gas, compression and associated economics to optimize CO_2 storage and CBM recovery both at the pilot and commercial scales. A second well was drilled and completed in the fall of 1999. Two flue gas micro-pilot tests, first of this kind in the world that involve injection of flue gas into a coal seam were carried out. Initially, core samples were taken from the second well and evaluated to determine the gas-in-place volume, gas composition, and gas storage capacity. The micro-pilot test was performed in the spring of 2000 by injecting a simulated flue gas steam consisting of two different ratios of N_2 and CO_2 to obtain greater methane recovery without any hindrance to CO_2 storage. The data will be used to finalize the design of the full-scale project that will be implemented in Phase III-B.

Phase III-B encompasses the implementation of a 5-spot field pilot, which would consist of four injection wells and one production wells, sized in a rectangular pattern between 20 and 40 acres. The objective of this phase would be to demonstrate the viability of a large-scale CO_2 storage/ECBM project and to obtain information on the specifications of the technology required to perform a full-scale development project. These specifications will be used to design flue gas collection and treatment facilities, compression, and gas production/separation facilities. The current plans call for the 5-spot pilot to be performed in the Fenn Big Valley site. Three additional wells will be drilled in 2001. These wells, along the one drilled in 1999 and the existing Gulf Canada well will comprise the 5 wells needed for the large pilot. Injection will begin in 2001 and will continue for 12 months.

If the large-scale pilot is successful, full-scale development could begin in 2003 either on the above site or at another suitable location in the Alberta Basin.

Although most of the work so far has focused on the Manville Group coals in the Fenn Big Valley area, a parallel study conducted by the Geological Survey of Canada evaluates the geological properties of other unminable coal seams in Alberta, such as those of the Edmonton and the Ardley groups (Upper Cretaceous-Lower Tertiary). The Edmonton coals are shallower than the Mannville coals and are located in closer proximity to major coal-fired power plants, thus making these coals favourable targets for CO_2 storage. On the other hand, the Ardley coals are being investigated because of their higher permeability and lower injection pressures and costs required for a successful pilot.

CONCLUSION

In conclusion, flue gas injection into coalbed reservoirs has scientific merit and is more economical than pure CO_2 injection for ECBM recovery purposes. Existing information on any field experience of injecting flue gas into geological formations is scarce. More work is needed on the gas treating, compression, and injection methods in order to allow us to determine the economics between CO_2 storage and methane production from coal beds.

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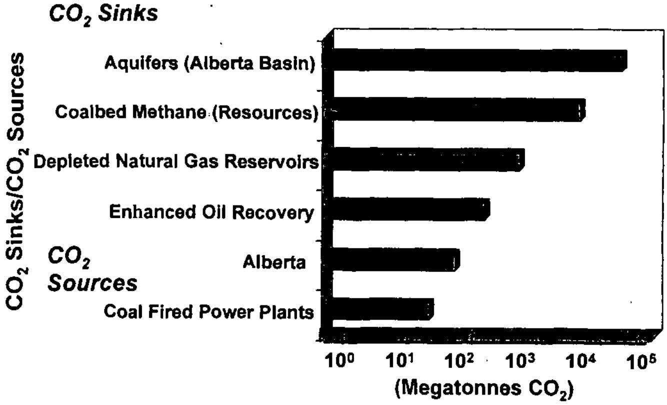

Figure 1 Emissions and greenhouse gas storage capacity in the Alberta basin.

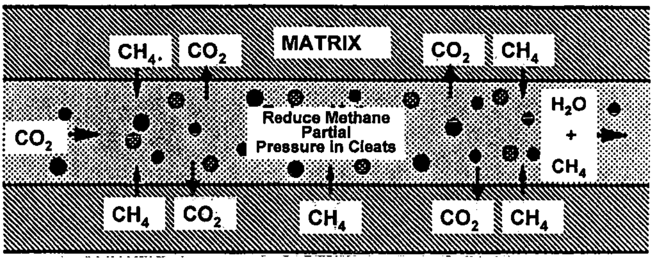

Figure 2 CO_2-enhanced coalbed methane recovery mechanism.

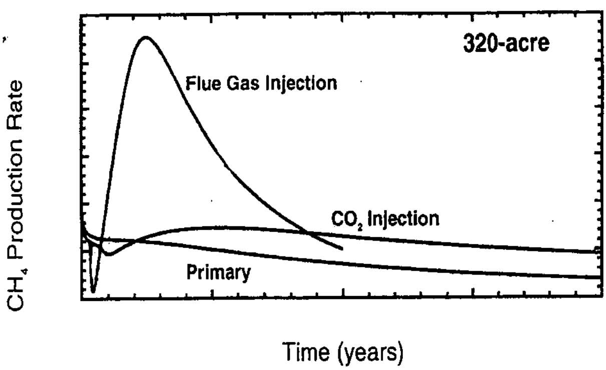

Figure 3 Coalbed methane production rate over time for primary recovery and as a result of pure CO_2 and flue gas injection.