A Technical and Economic Sensitivity Study of Enhanced Coalbed Methane Recovery and Carbon Sequestration in Coal

Topical Report

January 1, 2004 – March 31, 2004

Scott R. Reeves, Darrell W. Davis and
Anne Y. Oudinot

Advanced Resources International, Inc.
9801 Westheimer, Suite 805
Houston, Texas 77042

April, 2004

U.S. Department of Energy
DE-FC26-00NT40924

Advanced Resources International

Disclaimers

U.S. Department of Energy

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Advanced Resources International, Inc.

The material in this Report is intended for general information only. Any use of this material in relation to any specific application should be based on independent examination and verification of its unrestricted applicability for such use and on a determination of suitability for the application by professionally qualified personnel. No license under any Advanced Resources International, Inc., patents or other proprietary interest is implied by the publication of this Report. Those making use of or relying upon the material assume all risks and liability arising from such use or reliance.

Abstract

In October 2000, the U.S. Department of Energy (DOE), through contractor Advanced Resources International (ARI), launched a multi-year government-industry R&D collaboration called the Coal-Seq project[1]. The Coal-Seq project is investigating the feasibility of CO_2 sequestration in deep, unmineable coalseams by performing detailed reservoir studies of two enhanced coalbed methane recovery (ECBM) field projects in the San Juan basin. The two sites are the Allison Unit, operated by Burlington Resources, and into which CO_2 is being injected, and the Tiffany Unit, operated by BP America, into which N_2 is being injected (the interest in understanding the N_2-ECBM process has important implications for CO_2 sequestration via flue-gas injection). The purposes of the field studies are to understand the reservoir mechanisms of CO_2 and N_2 injection into coalseams, demonstrate the practical effectiveness of the ECBM and sequestration processes, demonstrate an engineering capability to model them, and to evaluate sequestration economics. In support of these efforts, laboratory and theoretical studies are also being performed to understand and model multi-component isotherm behavior, and coal permeability changes due to swelling with CO_2 injection.

To facilitate industry realization of the benefits of the improved knowledge of ECBM processes resulting from this project, a screening model was developed to predict the performance of ECBM/CO_2-sequestration projects under a broad set of reservoir conditions and operating assumptions (Coal-Seq V1.0)[2]. That model has proven to be a useful tool for project screening purposes. While a simplistic economic module was incorporated into the original model, recently it was upgraded with a much more rigorous handling of ECBM and sequestration economics (Coal-Seq V2.0)[3]. With this improved capability, a technical and economic sensitivity was performed using the model to evaluate the factors that influence ECBM recovery and carbon sequestration performance, and the types of conditions necessary for economically successful projects. This report describes the approach and results of that sensitivity study.

Based on the results presented in the report, the following major conclusions are drawn:

- An integrated technical and economic model has been developed for carbon sequestration and ECBM project screening and sensitivity analysis.
- N_2-ECBM appears to be more economically favorable than CO_2-ECBM, however an injection stream composed of mostly CO_2 is best for CO_2 sequestration economics.
- Not accounting for the detrimental effects of CO_2 on coal permeability and injectivity, ECBM operations are generally more favorable in low permeability, high rank coal environments. Greenfield projects are also generally better than brownfield projects. The implication is that deeper, lower permeability but higher rank coals, that have not been developed previously for conventional CBM production, are favorable targets for ECBM. Larger well spacings can also be favorable in these environments for N_2-ECBM.
- For these findings to be more generally applicable for CO_2 sequestration purposes, technology must be developed to overcome coal permeability and injectivity decline with CO_2 injection.

Table of Contents

List of Tables

List of Figures

1.0 Introduction and Prior Work

In October 2000, the U.S. Department of Energy (DOE), through contractor Advanced Resources International (ARI), launched a multi-year government-industry R&D collaboration called the Coal-Seq project[1]. The Coal-Seq project is investigating the feasibility of CO_2 sequestration in deep, unmineable coalseams by performing detailed reservoir studies of two enhanced coalbed methane recovery (ECBM) field projects in the San Juan basin. The two sites are the Allison Unit, operated by Burlington Resources, and into which CO_2 is being injected, and the Tiffany Unit, operated by BP America, into which N_2 is being injected (the interest in understanding the N_2-ECBM process has important implications for CO_2 sequestration via flue-gas injection). The purposes of the field studies are to understand the reservoir mechanisms of CO_2 and N_2 injection into coalseams, demonstrate the practical effectiveness of the ECBM and sequestration processes, demonstrate an engineering capability to model them, and to evaluate sequestration economics. In support of these efforts, laboratory and theoretical studies are also being performed to understand and model multi-component isotherm behavior, and coal permeability changes due to swelling with CO_2 injection.

To facilitate industry realization of the benefits of the improved knowledge of ECBM processes resulting from this project, a screening model was developed to predict the performance of ECBM/CO_2-sequestration projects under a broad set of reservoir conditions and operating assumptions (Coal-Seq V1.0)[2]. That model has proven to be a useful tool for project screening purposes. While a simplistic economic module was incorporated into the original model, recently it was upgraded with a much more rigorous handling of ECBM and sequestration economics (Coal-Seq V2.0)[3]. With this improved capability, a technical and economic sensitivity was performed using the model to evaluate the factors that influence ECBM recovery and carbon sequestration performance, and the types of conditions necessary for economically successful projects. This report describes the approach and results of that sensitivity study.

To begin, we first investigated what prior work had been performed to evaluate the economics of ECBM and carbon sequestration in coal. Some of the more relevant work in that regard is summarized below:

- The first (N_2-ECBM) economic evaluation was published by Stevenson et al at the University of New South Wales in 1993[4]. They performed an economic sensitivity study using reservoir simulation performance predictions based on San Juan basin conditions. Their major conclusions were:
  - N_2-ECBM may be more economically attractive than conventional pressure depletion for coalbed methane (CBM) production for lower permeability reservoirs where the loss in coal permeability with pressure decline is significant. Coals with high compressibility are particularly sensitive to this effect.
  - N_2-ECBM economics are highly sensitive to nitrogen generation (front-end) and separation (back-end) costs.
  - N_2-ECBM economics are also adversely affected by permeability heterogeneity, which impacts sweep efficiency (and N_2/coal contact volume).

- Wong and others at the Alberta Research Council have been studying CO_2 sequestration economics in coalseams since 2000[5,6,7]. In their work, they evaluated the economics of pure CO_2 injection and flue-gas injection (87% N_2, 13% CO_2) into coalseams of the Alberta Plains region. The major conclusions from that work were:
    - CO_2-ECBM economics are highly sensitive to CO_2 price, due to a high ratio of CO_2 volume required to produce a unit volume of methane (>2).
    - Flue-gas ECBM economics are much more favorable due to the high percentage of N_2 in the composition. The ratio of N_2 required to produce a volume of methane is much less than for CO_2 (<1).
    - From a carbon sequestration perspective however, where the net CO_2 avoided is the relevant benchmark (i.e., the total volume of CO_2 sequestered less the volume of CO_2 created in the sequestration process), flue gas injection does not provide any meaningful volume of net carbon sequestration.
    - A proprietary surface facilities computer model was developed for evaluating the economics of CO_2 capture and transportation, injection, and produced gas processing. An economic analysis of sequestering carbon from numerous CO_2 sources was performed. The results indicated that from a carbon sequestration perspective, a 100% CO_2 stream provided the best economic (lowest net sequestration cost) result.

- Finally, Shimada et al at the University of Tokyo also compared sequestration economics of CO_2 injection versus flue gas injection[8]. They used a reservoir simulator to generate methane production forecasts based on San Juan basin conditions, and considered several CO_2 sources, separation methods and source/sink proximities to evaluate sequestration economics. Similar to the work by the Alberta Research Council, they too concluded that 100% CO_2 injection was the most favorable economically from a net carbon sequestration perspective.

While this prior work is valuable and provides an important foundation of insight, there remain a number of unmet needs, namely:

- A coupled reservoir performance (simulation) and economic tool still does not exist in the public domain that independent researchers, power companies and CBM producers can use to evaluate and screen potential ECBM/sequestration projects.

- A comprehensive sensitivity study under a broad set of reservoir and operational conditions, and from both ECBM and carbon sequestration perspectives, still has not been performed.

This study, in combination with the Coal-Seq V2.0 model, seeks to meet these needs.

2.0 Description of Economic Model

As correctly highlighted in the prior studies, the economic problem to be evaluated is highly complicated, and must account for numerous inter-related and complex factors. Importantly, to be able to properly evaluate net sequestration economics, accounting for incremental CO_2 emissions along the entire chain of activities leading to eventual carbon sequestration is required. A description of some of the more relevant economic considerations accounted for in the Coal-Seq V2.0 model is provided below. Note that full details on the algorithms and calculations used in the Coal-Seq V2.0 model can be found in the Users Manual[3].

2.1 Carbon Capture

Due to its significance in terms of carbon emissions, carbon capture from utility-scale power plants is of particular interest. Therefore this is the focus of the model. However, other types of CO_2 sources (e.g., ammonia plants, LNG plants, natural sources, etc.) can also be evaluated. In addition, pure nitrogen sources, such as cryogenic air separation plants, can be studied for ECBM purposes.

Focusing on power plants, these come in different varieties, most notably pulverized coal (PC), natural gas combined cycle (NGCC), and integrated gasification combined cycle (IGCC). Likewise, CO_2 capture from each type of plant has different performance characteristics that impact economics, such as:

- Gross CO_2 emissions in terms of kg/MW-hr, and CO_2 concentration in %
- Costs to prepare the flue gas for carbon capture (e.g., sulphur, oxygen, SO_x and NO_x removal, etc.), in $/ton
- Capital and operating costs of the capture equipment, in $/ton
- Capture efficiency
- Increased CO_2 emissions that result from carbon capture, as a % of base-case (no capture) emissions

The ability to account for each of these factors is incorporated into the model. Further, different (N_2/CO_2) mixture compositions can be evaluated based on how much flue gas is actually treated for carbon capture. For example, if a 50-50 mixture of CO_2 and N_2 is desired for injection into a coalseam, and if the original flue gas contains 85% nitrogen and 15% carbon dioxide, then only a portion of the total flue gas stream would be processed for carbon capture, then remixed with untreated flue gas. This capability exists in the model.

Finally, there are (at least) two ways to estimate the overall size of an integrated carbon capture and ECBM/sequestration operation. One is by fixing the CO_2 (or N_2) source plant size and type (i.e., the volume of emissions), and then sizing the sequestration facilities (size of the CBM field) accordingly. The other is to fix the size of the CBM field (and thus its sequestration capacity), and compute the size of CO_2 source required. The model allows either approach to be used.

2.2 Transportation

There are two main cost elements to be considered related to the transportation of the injectant gas from the capture site to the injection site: 1) compression or pumping, and 2) the pipeline itself. The model considerations for each of these include:

- It is less expensive to transport CO_2 as a liquid, therefore for pure CO_2, pumping is assumed to occur. If nitrogen is included in the mixture, it is assumed that it would be transported as a gas, and therefore compression would be used. In either case, the capital and operating costs must be estimated based on the throughput volumes assumed, as must the CO_2 generated by the process (for net sequestration purposes). Compression efficiency is also considered. The capital and operating costs for these facilities are estimated based on input values of $/BHP (brake horsepower, which is computed based on the volume to be compressed/pumped and the pressure increase required). CO_2 emissions resulting from these operations are also accounted for; the amount of CO_2 emitted is therefore also an input, in terms of Mcfd/BHP.

- Sizing of the pipeline is performed by assuming a 2000 psi inlet pressure at the CO_2 capture plant (or other source), and a 1500 psi discharge pressure at the sequestration field, for a 500 psi pressure drop, as well as the assumed pipeline length. This pressure range was established to make the iterative procedure of sizing the pipeline more easily accomplished – varying pipeline operating pressures would require a comprehensive pipeline model be created, with variable fluid properties as a function of pressure, which was beyond the scope of this analysis. The actual pressures assumed were based on maintaining CO_2 in the liquid state for the entire length of pipeline. The pipeline capital and operating costs are estimated based on unit values of $/inch-mile (capital) and $/Mcf transported (operating).

Note that for pure N_2-ECBM, compression/pipeline costs are assumed to be zero since it is assumed that the nitrogen plant would be located at the CBM field.

2.3 CBM Field Booster Compression/Pumping

In some cases the injection gas will require booster compression (or booster pumping in the case of pure CO_2) after arriving at the CBM field at 1500 psi to the required wellhead injection pressure. The required injection pressure is estimated based on a selected value of reservoir pressure (in units of psi per foot of depth; net of hydrostatic head and friction pressures, at the wellhead.). For shallow coal reservoirs, no pressure boosting is required. However deeper coals will probably require booster compression/pumping. The costs and incremental CO_2 emissions associated with booster compression/pumping are computed using the same inputs as for compression/pumping at the source site.

2.4 Well Costs

Several separate scenarios can be evaluated with the Coal-Seq V2.0 model:

- ***Incremental***, whereby a producing CBM field is assumed to exist (or will exist), and the economics are computed on an incremental basis over baseline primary production. This is also referred to as the brownfield case. In this case, the following parameters are required:
    - Workover costs to upgrade the existing production wells to CO_2 service. If the field is to be used for sequestration purposes, these costs may be increased over the purely ECBM case to account for operations to ensure that leakage does not occur through the older wellbores. It is assumed that all wells in the field would be worked over, but the per-well value could be reduced to account for fewer wells if that is the case.
    - Capital and operating costs for new CO_2 injection wells. It is assumed in the model that an injector: producer ratio of 1:1 is used (i.e., a 5-spot configuration). This is an inherent assumption in the reservoir simulation runs contained in the model, and hence should not be changed.
    - A gas injection reticulation system must also be installed. The capital cost of the system is estimated on a per-well basis, and included in the injection well capital cost.

  Note that in this case the economics can be computed on the following bases:
    - At time zero, whereby the incremental benefits of ECBM can be computed at the time of initial CBM drilling.
    - At some time in the future, whereby the incremental benefits of ECBM can be computed after years of primary CBM production.

- ***Full Project***, where no wells are assumed to exist, and the entire project economics must be computed. This is sometimes referred to as the greenfield case. In this case, the only difference with the incremental case is that the workover costs for the production wells are replaced with a capital cost of production wells. These costs would be inclusive of roads, locations, drilling, completion, stimulation, production equipment, flowlines, etc. All other values would remain the same (e.g., gas processing costs in $/Mcf as described below). Note however that instead of incremental methane production, total gas production is used as the basis of the economic calculations.

2.5 Produced Gas Processing

The produced gas (methane) processing consists of two compenents:

- **Separation**, which consists of separating the methane from CO_2, N_2, or both. This is estimated in $/Mcf of incremental (brownfield) or total (greenfield) gas produced. This value should be higher when N_2 is present since the cost to separate N_2 from natural gas is much higher than the cost of separating CO_2 from natural gas.

- **Compression/Dehydration**, to compress the pure methane stream from an assumed separation outlet pressure of 200 psi to an assumed pipeline pressure of 1000 psi. This value used is the same as for previous compression estimation.

2.6 Recycling

The option exists in the model to re-inject the separated CO_2 and/or N_2. If this option is selected, the purchased volumes (and costs) from the source are reduced. The net effects on sequestration volumes are also accounted for. The only additional information required under this option are the costs to compress the gas from an assumed ex-separation plant pressure of 15 psi to the appropriate injection pressure for the case being evaluated. In addition, CO_2 emissions resulting from this operation are also accounted for.

2.7 Safety, Monitoring and Verification

If the subject project is being performed for sequestration purposes, then some accounting for safety, monitoring and verification expenses must be included. Since there are no field examples or existing projects against which to benchmark activities and costs on this issue, these costs are simply input in terms of $M/injector well/year.

2.8 Financial Considerations

Financial parameters used in the model include:

- Net revenue interest, %
- Production taxes, %
- Wellhead natural gas price, $/MMBTU
- Gas price escalation, %/year
- Natural gas heating value, MMBTU/scf
- Carbon sequestration credit, if any, $/ton
- Discount rate, %

2.9 Economic Calculations

The following results are then provided for each case. Note that for brownfield developments they are on an incremental basis, and for a greenfield development they are on a total basis:

For All Cases:

- Net present value (NPV), in $
- Breakeven natural gas price, in $/Mcf
- Breakeven injection gas price at the capture plant location (including compression), in $/Mcf and $/ton
- Methane produced, in Bcf

For CO_2 Sequestration Cases:

- Total CO_2 injected, total reproduced, net remaining in coal, CO_2 produced as a result of sequestration operations, and net CO_2 sequestration volume, in tons
- Net sequestration cost, in $/ton of CO_2

3.0 Sensitivity to Reservoir Parameters

The first step in our analysis was to perform a technical sensitivity of the ECBM and carbon sequestration process in coals. On the reservoir side, the Coal-Seq V2.0 model consists of a database of 1975 simulation runs out of a total of all possible combinations of 2268 (3^7 runs plus a no-injection scenario for each case); some runs could not be completed due to incompatible reservoir/operating conditions, such as low permeability and high injection rates for example. ARI's COMET3 simulator was utilized to populate the database. A technical description of the simulator can be found in the references[9]. The user can then select one of three values for seven different parameters, as follows:

- Permeability: 1 mD, 10 mD or 100 mD
- Spacing: 40 acres, 160 acres or 640 acres
- Depth: 1,000 ft, 5,000 ft or 10,000 ft
- Coal Rank: high, medium or low
- Injection Rate: 10 Mscfd/ft, 50 Mscfd/ft or 100 Mscfd/ft
- Injection Gas: 100% CO_2, 100% N_2 or 50% CO_2 / 50% N_2
- Injection Timing: the first 7.5 years, the second 7.5 years or continuous for 15 years

In addition, the user can specify any coal thickness; the results from the database (which were all run with a thickness of 10 feet), are automatically scaled up or down according to the input coal thickness.

For this analysis, a base case set of conditions using the middle value for each of the above parameter selections was chosen, together with a coal thickness of 50 feet. To start, three cases were run to investigate the performance of a greenfield project at each gas mixture with injection over the entire 15 year project life. The results, shown in Figure 1, indicate that 100% N_2 provides the greatest methane recovery, followed by the 50/50 mixture, lastly 100% CO_2. This is an expected result since all cases assume the same injection rate, and since the injection/production ratio is less for N_2 than for CO_2, for equal injection volumes N_2 will recover more methane. Note however that N_2 tends to breakthrough to the producing wells early, whereas CO_2 does not. Since the 50/50 mixture falls between the results for each gas individually, further (technical) analysis was limited to 100% N_2 or 100% CO_2 (i.e., the "endpoints").

Next, the impact of injection timing was examined. Figure 2 presents the results. For either gas, continuous injection is superior to partial injection. For partial injection, early injection is better than late injection. The difference in early vs. late injection is significantly more pronounced for CO_2 than for N_2 , due to a slower methane response for CO_2 injection.

Next, runs were made using continuous pure CO_2 or pure N_2 injection, individually varying each of the other parameters (i.e., permeability, spacing, depth, coal rank and injection rate). Those results, presented in Figures 3-7, indicate:

- High permeabilities lead to overall higher methane recoveries (Figure 3). However, incremental recoveries are less for higher permeability. This is because higher permeability coals recover more methane under primary pressure depletion, leaving less behind for ECBM.

- Larger well spacing leads to greater overall and incremental methane recoveries (Figure 4). This is similar to conventional CBM and for the same reasons. The incremental benefits of larger well spacings can be better realized with N_2 injection.
- Deeper depths have higher total gas recovery (higher OGIP), but incremental recovery is less sensitive to depth (Figure 5). Note that coal permeability and rank are unaffected by depth in this comparison. This means that incremental methane recovery is proportional to gas injection volumes. Thus there is little difference in the results.
- Total and incremental recoveries are highly sensitive to coal rank (Figure 6). This is believed due to higher rank coals having more OGIP, as well as a "steeper" isotherm that would benefit from ECBM.
- Finally, higher injection rates generally tend to provide greater total and incremental methane production (Figure 7). However, in the case of N_2, too high a rate can lead to rapid N_2 breakthrough, poor sweep efficiency and lesser incremental methane recovery.

Based on these overall results, from an incremental methane recovery perspective, the following general observations can be made:

- N_2-ECBM provides better and faster methane recovery than CO_2-ECBM. However, N_2 breakthrough can be rapid, particularly with high injection rates, and compromise sweep efficiency and effectiveness. For CO_2-ECBM, the higher the injection rate the better.
- Lower permeability, high coal rank reservoirs appear to be more favorable for ECBM (i.e., generally deeper coals). Note that this observation is made in the absence of considering coal swelling and permeability reduction with CO_2 injection. Larger well spacings can also be favorable with N_2-ECBM.

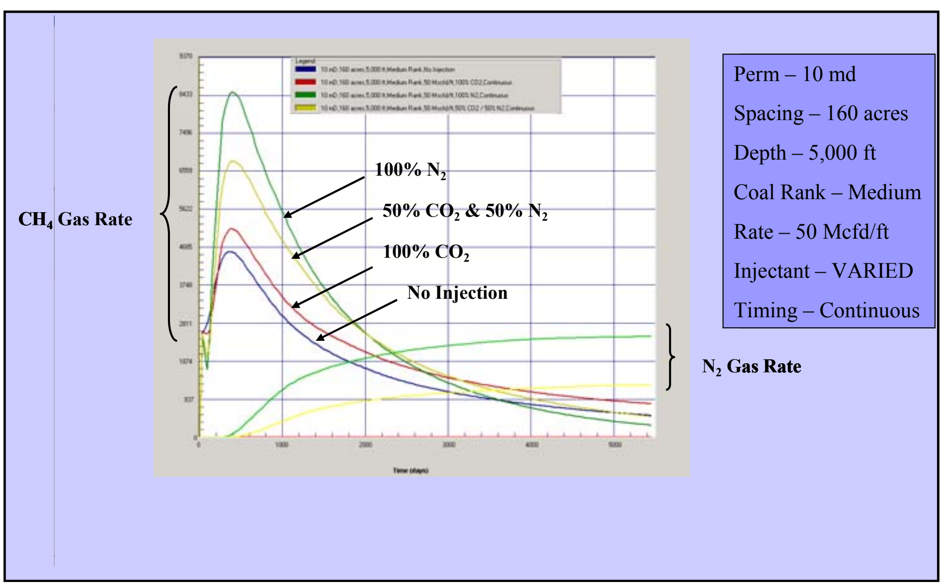

Figure 1: Effect of Injectant Composition

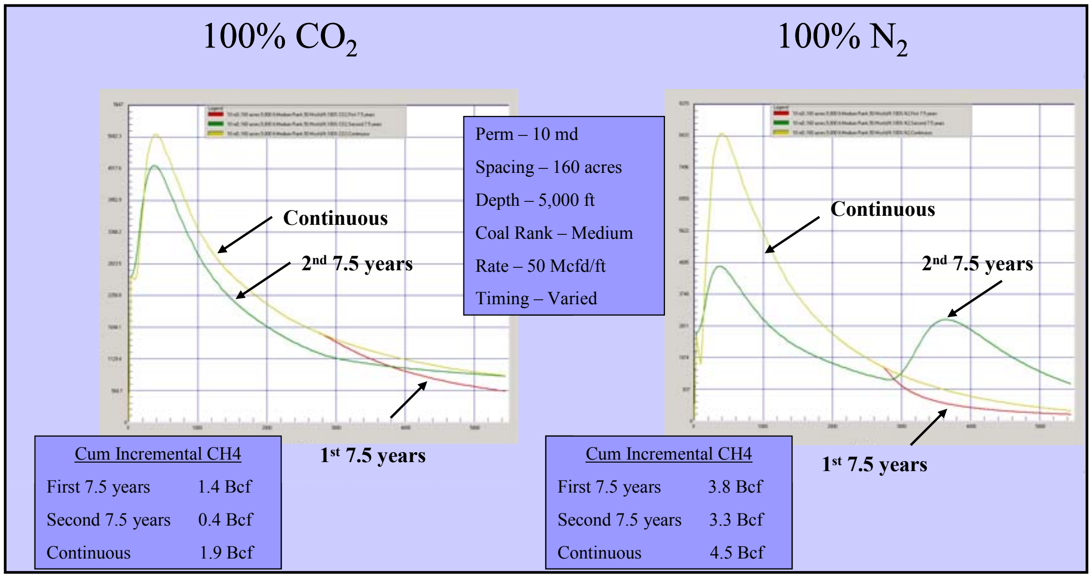

Figure 2: Effect of Injection Timing

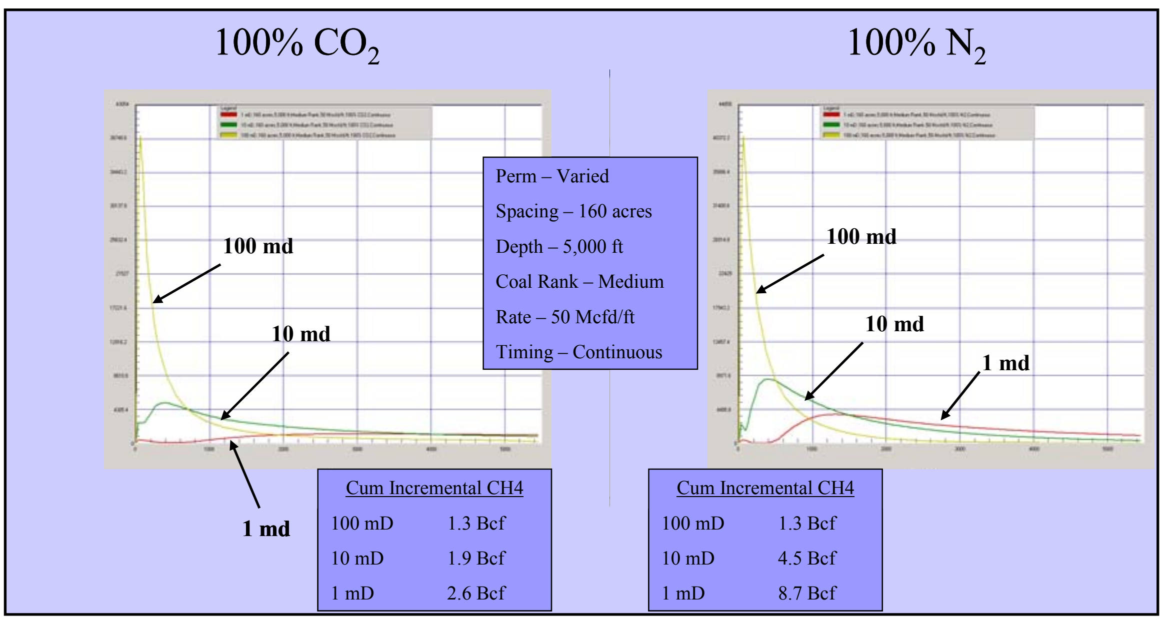

Figure 3: Effect of Permeability

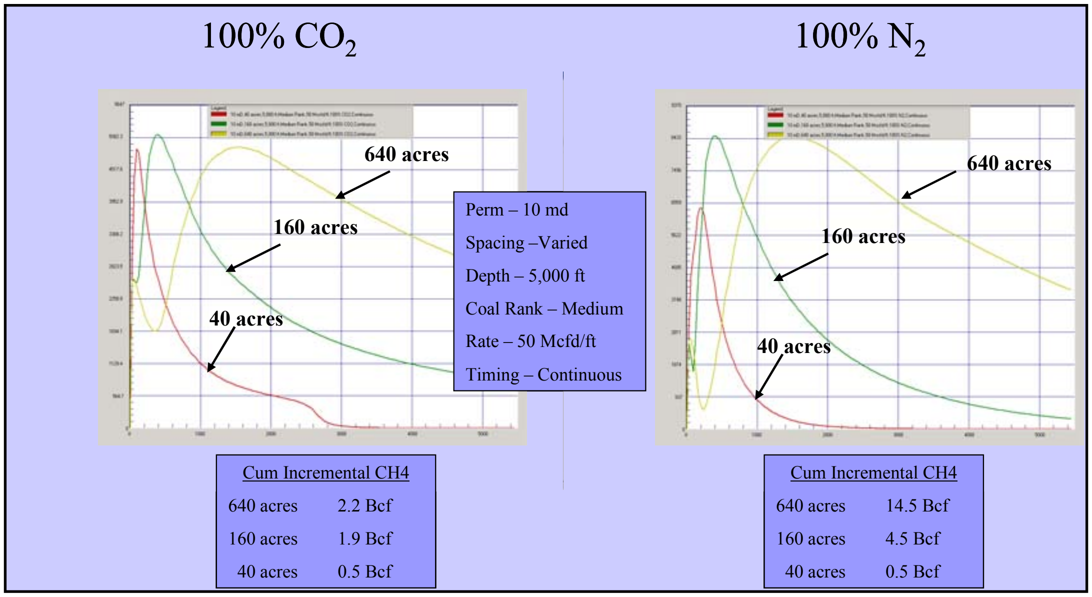

Figure 4: Effect of Well Spacing

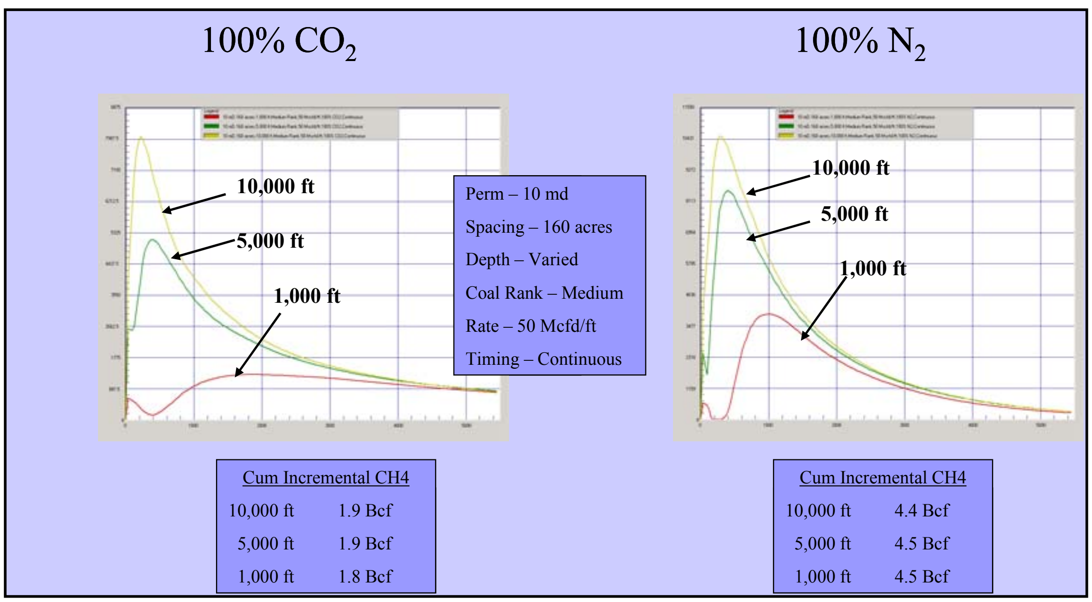

Figure 5: Effect of Well Depth

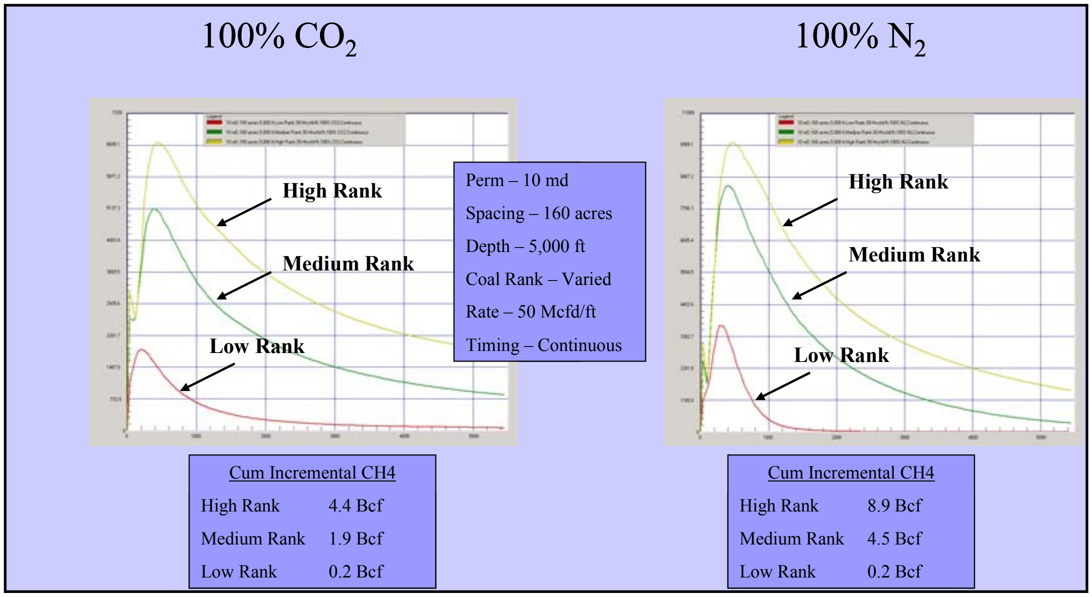

Figure 6: Effect of Coal Rank

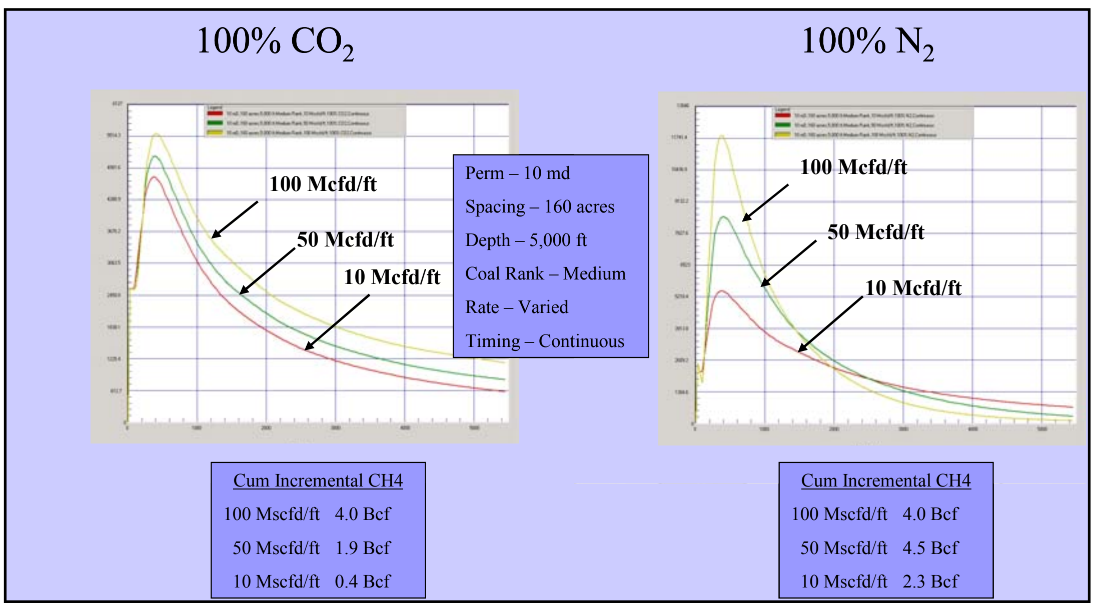

Figure 7: Effect of Injection Rate

4.0 Sensitivity to Economic Parameters

For the economic sensitivity study, a base-case set of economic parameters was first established. These are presented in Tables 1- 4. Where applicable, the source of the value is provided in the references.

Table 1: Base-Case CO_2 Source Parameters [10,11]

Plant Type	CO_2 Emissions	CO_2 Content	Capture Efficiency	Increase in CO_2 Emmissions w/ Capture	CO_2 Price ($/ton)
PC	850 kg/mw-hr	14%	90%	33.4%	$29.94
NGCC	370 kg/mw-hr	4%	90%	6.8%	$23.59
IGCC	670 kg/mw-hr	9%	90%	5.5%	$19.96

Table 2: Base-Case Capex & Opex Costs

	Capex	Opex
New Production Wells	$100/ft	$1,000/mo
New Injection Wells	$100/ft	$1,000/mo
Workovers	$20/ft	n/a
Pipeline	$20,000/in-mile	$.01/Mcf
Compression	$1500/BHP	$0.30/Mcf
Pumping	$200/BHP	$2/ton
Gas Processing – CO_2	n/a	$0.50/Mcf
Gas Processing – N_2	n/a	$050/Mcf
Safety, Monitoring and Verification	n/a	$10,000/injector/yr

Table 3: Base-Case Financial Parameters

Net Revenue Interest	87.5%
Production Taxes	4.6%
Gas Price	\$4.00 /MMBTU
Annual Gas Price Escalation	0%
Gas Heating Value	1050 MMBTU/Scf
CO_2 Credit	0 \$/ton
Discount Rate	10%

Table 4: Other Base-Case Parameters

Injection Gradient	0.7 psi/ft
Compressor Efficiency	75%
Gas Specific Gravity	0.6 (air = 1.0)
Compression/Pumping CO_2 Emissions	12 tons/yr/BHP[12,13]

With these base-case economic parameters, sensitivities were performed to answer the following questions:

- Which type of power plant provides the best sequestration economics?
- What coal reservoir environment provides the best sequestration economics?
- What gas composition provides the best sequestration economics?
- Which are better: greenfield or brownfield projects?
- What conditions provide the best ECBM economics?
- How sensitive are results to gas price?
- How would CO_2 credits improve the results?
- How important is project scale?
- How important is source/sink proximity?
- Is it worthwhile to capture/recycle N_2 for an ECBM project?

To begin, in addition to the base case assumptions presented in Tables 1-4, we used the base case reservoir assumptions from the Section 3 of this report (Technical Sensitivity), or the middle value for each reservoir parameter. We also assumed a project size of 100 5-spot well patterns which, at 50 feet of coal and an injection rate of 50 Mcfd/ft of coal, is a total injection volume of 250 MMcf/d, or almost 15,000 tons/d if pure CO_2. Thus the project size is considerable.

The first analysis evaluated which type of power plant provides the best carbon sequestration economics. The results, provided in Table 5, not surprisingly show a parallel trend to CO_2 capture costs as provided in Table 1 (i.e., IGCC the lowest cost and PC the highest). The high cost of CO_2 capture for the PC plant is largely attributable to the high CO_2 emissions penalty

(33%) assumed for this plant type. Note that in each case, the total sequestration cost is less than the capture costs shown in Table 1, indicating the incremental methane recovery is successfully offsetting some of the capture costs. Note also that the sequestration costs are less favorable when a 50/50 mixture of CO_2/N_2 is used. This is due to additional capital costs related to N_2 separation and recycling, and lesser net sequestration volumes (due to lesser injection volumes as well as additional carbon emissions).

Table 5: Sequestration Costs (Breakeven Gas Price) by Plant Type

	IGCC $/ton ($/Mcf)	NGCC $/ton ($/Mcf)	PC $/ton ($/Mcf)
100% CO_2	$11.74 ($13.92)	$13.98 ($15.64)	$26.22 ($18.65)
50% CO_2/50% N_2	$24.63 ($5.50)	$31.25 ($5.83)	$368.72 ($6.40)

Table 6 summarizes the accounting for net sequestration volumes, in this case for an IGCC plant. Total injection volumes are on the top row, and each additional row is for an additional emission associated with the process that reduces net sequestration volume. Each CO_2 generating activity is accounted for, including reproduced CO_2 (which did not occur in any of the cases evaluated).

Table 6: Makeup of Net Sequestration Volume (Tons)

	100% CO_2	50% CO_2/50% N_2	100% N_2
CO_2 Injection	78,171,265	39,088,709	n/a
CO_2 Production	n/a	n/a	n/a
CO_2 Capture Plant	(4,783,792)	(2,392,084)	n/a
N_2 Compression	n/a	(4,613,100)	n/a
N_2 Capture Plant	n/a	n/a	(6,852,600)
Booster Compression	n/a	(2,103,200)	(4,187,200)
Booster Pump	(105,420)	n/a	n/a
Sales Compressor	(1,734,127)	(3,465,627)	(4,329,006)
Recycle Compressor	n/a	(12,934,800)	(27,348,600)
Total	**71,547,926**	**13,579,898**	**(42,717,406)**

The next issue evaluated was what coal reservoir environment provides the best sequestration economics. Tables 7 and 8 provide the net sequestration costs (and breakeven gas price) for different coal permeability and rank respectively. Not dissimilar to the results of the technical sensitivity, lower coal permeability and higher coal rank appears more favorable for sequestration economics. It is interesting to also note that for high rank coals, the inclusion of nitrogen provides improved sequestration economics over the pure CO_2 case.

Table 7: Effect of Coal Permeability on Sequestration Economics

	1mD $/ton ($/Mcf)	10mD $/ton ($/Mcf)	100mD $/ton ($/Mcf)
100% CO_2	$11.88 ($13.76)	$11.74 ($13.92)	$12.85 ($19.70)
50% CO_2/50% N_2	$8.92 ($4.37)	$24.63 ($5.50)	$48.05 ($11.53)

Table 8: Effect of Coal Rank on Sequestration Economics

	Low Rank $/ton ($/Mcf)	Medium Rank $/ton ($/Mcf)	High Rank $/ton ($/Mcf)
100% CO_2	$14.66 (>$40)	$11.74 ($13.92)	$7.32 ($6.69)
50% CO_2/50% N_2	$59.42 ($37.72)	$24.63 ($5.50)	-$9.45 ($3.71)

Next, a comparison of greenfield versus brownfield projects was examined. Those results are shown in Table 9. These results indicate that in general greenfield projects provide better economic results than brownfield projects. As mentioned previously, this is because greater incremental methane recoveries are possible with Greenfield projects versus brownfield projects.

Table 9: Greenfield versus Brownfield Project Economics

	Incremental Economics		
	Greenfield		Brownfield
	Continuous $/ton ($/Mcf)	First 7.5 years $/ton ($/Mcf)	Second 7.5 years $/ton ($/Mcf)
100% CO_2	$11.74 ($13.92)	$15.61 ($11.69)	$19.27 ($35.91)
50% CO_2/50% N_2	$24.63 ($5.50)	$27.44 ($4.74)	$67.30 ($6.13)

Next, the impact of gas price, project scale and source/sink proximity were evaluated. Those results are provided in Figures 8 through 10. The results indicate that:

- Sequestration economics appear to be linearly related to gas price. In this particular case, there is a decrease in net sequestration cost of $1/ton for each $1/Mcf increase in gas price.
- For this particular set of conditions, there does not appear to be considerable effect of either scale or source/sink proximity on net sequestration costs.

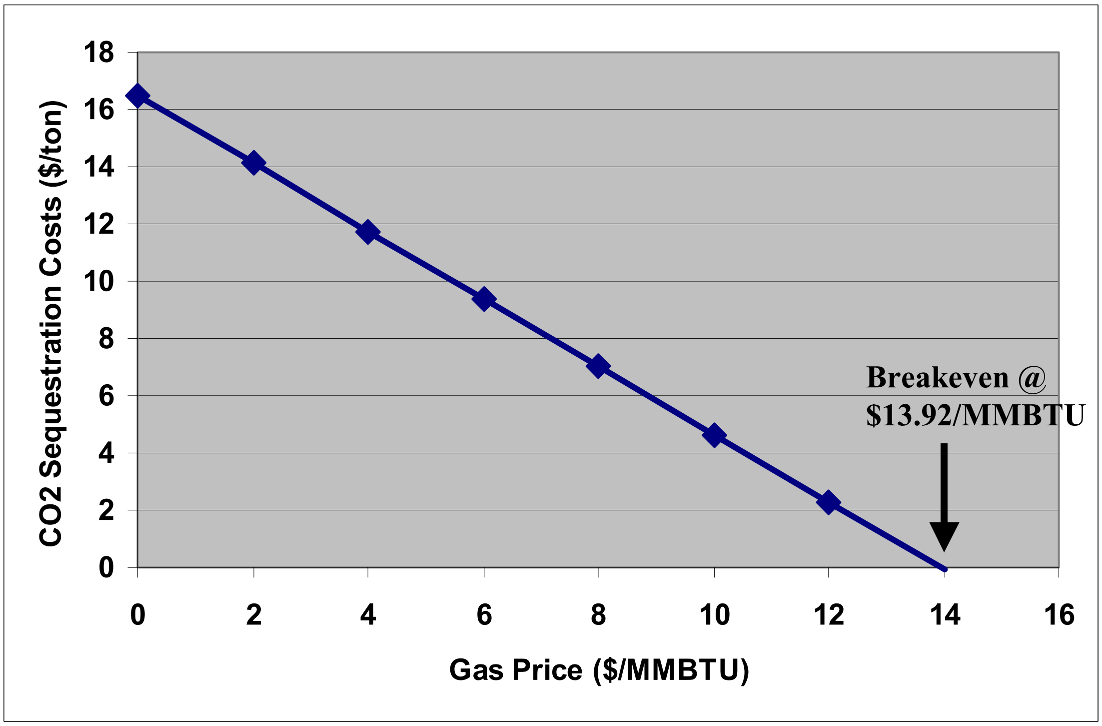

Figure 8: Effect of Gas Price on Sequestration Economics

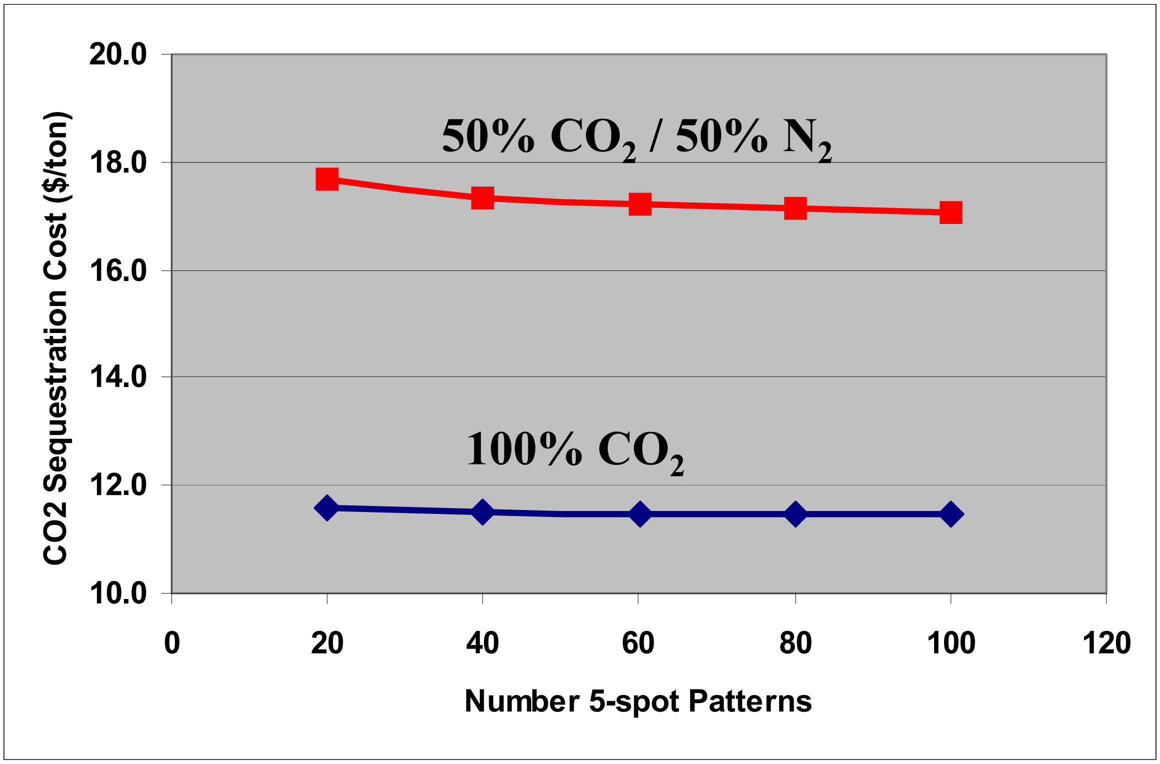

Figure 9: Effect of Project Size on Sequestration Economics

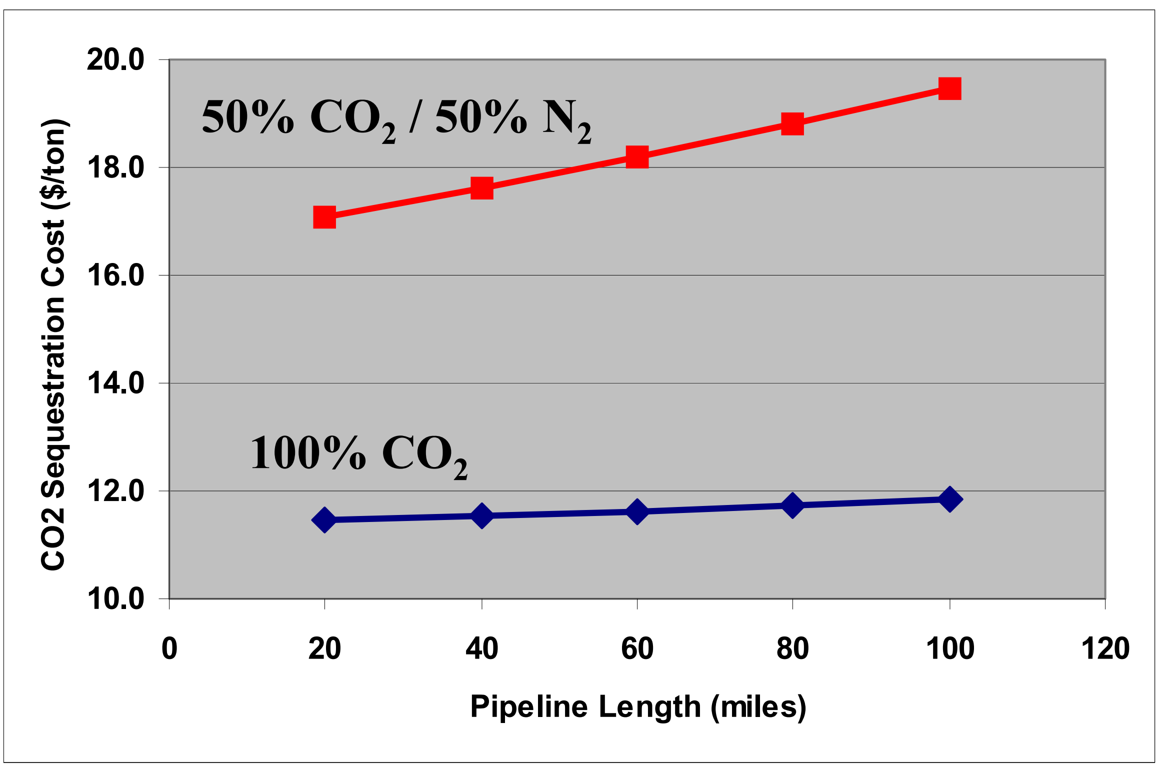

Figure 10: Effect of Source/Sink Proximity on Sequestration Economics

Finally, the benefits of N_2 recycling on N_2-ECBM project economics were assessed. Those results are presented in Table 10, in the form of breakeven gas price. These results indicate that recycling can marginally improve project economics. However, it is likely that this will be highly site specific.

Table 10: Effect of N_2 Recycling on N_2-ECBM Economics

	Breakeven Gas Price ($/MMBTU)	
	Without N_2 Recycling	**With N_2 Recycling**
100% CO_2	$13.92	$13.92
50% CO_2/50% N_2	$5.05	$5.50
100% N_2	$5.27	$4.82

5.0 Conclusions

Based on the results presented in the report, the following major conclusions are drawn:

- An integrated technical and economic model has been developed for carbon sequestration and ECBM project screening and sensitivity analysis.
- N_2-ECBM appears to be more economically favorable than CO_2-ECBM, however an injection stream composed of mostly CO_2 is best for CO_2 sequestration economics.
- Not accounting for the detrimental effects of CO_2 on coal permeability and injectivity, ECBM operations are generally more favorable in low permeability, high rank coal environments. Greenfield projects are also generally better than brownfield projects. The implication is that deeper, lower permeability but higher rank coals, that have not been developed previously for conventional CBM production, are favorable targets for ECBM. Larger well spacings can also be favorable in these environments for N_2-ECBM.
- For these findings to be more generally applicable for CO_2 sequestration purposes, technology must be developed to overcome coal permeability and injectivity decline with CO_2 injection.

6.0 References

1) Reeves, S. R.: "Geologic Sequestration of CO_2 in Deep, Unmineable Coalbeds: An Integrated Research and Commercial-Scale Field Demonstration Project", SPE 71749, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, September 30-October 3, 2001.

2) Taillefert, Anne Y., Reeves, S. R.: "Screening Model for ECBM Recovery and CO_2 Sequestration in Coal", Coal-Seq V1.0, DOE Topical Report, Houston, TX, June, 2003.

3) Davis, Darrell W., Oudinot, Anne Y., Sultana, Aiysha, and Reeves, S. R.: "Screening Model for ECBM Recovery and CO_2 Sequestration in Coal", Coal-Seq V2.0, DOE Topical Report, Houston, TX, March, 2004.

4) Stevenson, M. D., Pinczewski, W. V., and Downey, R. A.; "Economic Evaluation of Nitrogen Injection for Coalseam Gas Recovery", SPE 26199, presented at the SPE Gas Technology Symposium held in Calgary, Alberta, Canada, 28-30 June, 1993.

5) Wong, S., Gunter, W. D., Mavor, M. J.: "Economics of CO_2 Sequestration in Coalbed Methane Reservoirs", SPE 59785, presented at the SPE/CERI Gas Technology Symposium, Calgary, Alberta Canada, 3-5 April, 2000.

6) Wong, S., Gunter, W. D, Lane, D., and Mavor, M. J.; "Economics of Flue Gas Injection and CO_2 Sequestration in Coalbed Methane Reservoirs", presented at the Fifth International Conference on Greenhouse Gas Control Technologies, August 13-16, 2000, Cairns, Austrialia.

7) Macdonald, D., Wong, S., Gunter, B., Nelson, R. Reynen, B.; "Surface Facilities Computer Model: An Evaluation Tool for Enhanced Coalbed Methane Recovery", presented at the Sixth International Conference on Greenhouse Gas Control Technologies, 30th September – 4th October, 2002, Kyoto, Japan.

8) Shimada, S., Sekiguchi, T., and Matsui, T.: "Economic Assessment of CO_2 Sequestration in Coal Seam", presented at the Sixth International Conference on Greenhouse Gas Control Technologies, 30th September – 4th October, 2002, Kyoto, Japan.

9) Sawyer, W.K., Paul, G.W., Schraufnagel, R.A., "Development and Application of a 3D Coalbed Simulator," CIM/SPE 90-119, presented at the CIM/SPE International Technical Conference, Calgary, June 10-13, 1990.

10) David, J.: "Economic Evaluation of Leading Technology Options for Sequestration of Carbon Dioxide", submitted to the Engineering Systems Division at the Massachusetts Institute of Technology, May, 2000.

11) Narula, Ram. G., Wen, H., and Himes, K.: "Incremental Cost of CO_2 Reduction in Power Plants", GT-2002-30259, presented to the proceedings of IGTI ASME Turbo Expo 2002, June 3-6, 2002, Amsterdam, The Netherlands.

12) Zhang, Li Ya, Smith, Duncan, Zhang, Peng: “Compressor Station Optimization During Gas Injection into Underground Storage”.

13) “Synopsis of API’s Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry” – API’s Greenhouse Gas Emissions Methodologies Work Group.