CO_2 Sequestration Potential of Texas Low-Rank Coals

Quarterly Technical Progress Report

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ABSTRACT

The objectives of this project are to evaluate the feasibility of carbon dioxide (CO_2) sequestration in Texas low-rank coals and to determine the potential for enhanced coalbed methane (ECBM) recovery as an added benefit of sequestration. In this reporting period we revised all of the economic calculations, participated in technology transfer of project results, and began working on project closeout tasks in anticipation of the project ending December 31, 2005.

In this research, we conducted five separate simulation investigations, or cases. These cases are (1) CO_2 sequestration base case scenarios for 4,000-ft and 6,200-ft depth coal beds in the Lower Calvert Bluff Formation of east-central Texas, (2) sensitivity study of the effects of well spacing on sequestration, (3) sensitivity study of the effects of injection gas composition, (4) sensitivity study of the effects of injection rate, and (5) sensitivity study of the effects of coal dewatering prior to CO_2 injection/sequestration. Results show that, in most cases, revenue from coalbed methane production does not completely offset the costs of CO_2 sequestration in Texas low-rank coals, indicating that CO_2 injection is not economically feasible for the ranges of gas prices and carbon credits investigated. The best economic performance is obtained with flue gas (13% CO_2 - 87% N_2) injection, as compared to injection of 100% CO2 and a mixture of 50% CO_2 and 50% N_2.

As part of technology transfer for this project, we presented results at the West Texas Geological Society Fall Symposium in October 2005 and at the COAL-SEQ Forum in November 2005.

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INTRODUCTION

The objectives of this project are to evaluate the feasibility of carbon dioxide (CO_2) sequestration in Texas low-rank coals and to determine the potential for enhanced coalbed methane recovery as an added benefit of sequestration. During this reporting period, we continued and revised economic studies of CO_2 sequestration and enhanced coalbed methane (ECBM) recovery in the Wilcox coals in east-central Texas.

EXPERIMENTAL

No experimental procedures were conducted during this period.

RESULTS AND DISCUSSION

Economic Modeling

During this quarter, we focused research on economic modeling. Previously, we reported on probabilistic economic analysis that was conducted for a single 5-spot pattern and incorporated injection and production results from our reservoir simulation studies. Fieldwide costs, such as the cost of a pipeline to transport CO2 to the field, were allocated to an individual pattern based on the number of patterns required for a specified well spacing. The economic model and parameters reported on this quarter are similar to those presented in previous reports. However, in the revised analysis presented in this report, we explicitly include compression costs. Previously, compression costs were included implicitly, which resulted in underestimation of the costs. In addition, we widened the probability distributions for some parameters, such as gas prices and carbon market prices, to better reflect the uncertainties in these parameters. Finally, we now summarize economic results in terms of present value ratio (ratio of net present value to investment), NPV/I, instead of NPV. NPV/I is a more useful economic indicator for comparing varied investment opportunities. In the following sections, we present revised economic results, but also present a more detailed documentation of our economic modeling assumptions and parameter values than presented in previous reports.

Economic Model Parameters

The parameters used in the economic analysis are listed in Table 1 and further explained here.

Gas Price. A triangular distribution was used to model uncertainties in gas prices. Minimum, most likely and maximum values of \$2.00, \$4.00 and \$12.00 per Mscf of CH_4 were used for the gas price distribution. This triangular distribution was escalated at a rate of 3% per year.

Net Revenue Interest. A uniform distribution was used to model uncertainties in net revenue interest. Minimum and maximum values of 75% and 80% were used, based on typical royalty interests in the area.

Carbon Market Price. The term "carbon market price" is used in this report to represent the price of CO_2 in the carbon market - a market in which entities, such as governments and companies, trade in CO_2 to fulfill local or Kyoto Protocol obligations. The carbon market is more developed in Europe than in the United States. The carbon market in the United States has a significantly lower CO_2 price ($0.07 per Mscf of CO_2 or $1.33 per ton of CO_2) compared to Europe ($1.05 per Mscf of CO_2 or $20.00 per ton of CO_2). In this study, a uniform distribution was used to model the uncertainties in carbon market price. Minimum and maximum values of $0.05 per Mscf of CO_2 ($1.00 per ton of CO_2) and $1.58 per Mscf of CO_2 ($30.00 per ton of CO_2) were used.

Sequestration Credits. It has been suggested by Wong *et al.*[1] that the costs of CO_2 capture must be lowered or credits for CO_2 sequestration must be created in order to make CO_2 sequestration economic. There is currently no official method of computing and applying credits to carbon sequestration projects. Wong *et al.*[1,2] also suggest that CO_2 credits must be based on a "CO_2 avoided" basis. Reeves *et al.*[3] and King[4] are in agreement with this concept. In other words, CO_2 produced in the processes used for CO_2 capture and CO_2 emitted during the compression process must be accounted for in computing a net CO_2 sequestered or CO_2 avoided. Thus, the operator does not receive credit for all the CO_2 sequestered. Reeves *et al.*[3] give an example calculation of the net CO_2 sequestered for an IGCC plant. However, the methods for calculating the values are not stated. Wong *et al.*[1] also provide an illustrative example. The computed net sequestered CO_2 is about 64% of the CO_2 injected.

In our economic analysis, CO_2 credits are treated as an additional source of revenue for the company undertaking the project. A net-to-gross CO_2 sequestered ratio of 70% is assumed. Thus, Sequestration Credits = 70% * Volume of CO_2 Injected * CO_2 Market Price.

Area. We assumed a project area of 30,000 acres, based on preliminary studies.[5] Studies were run at different well spacings (40, 80, 160, and 240 ac). The number of 5-spot patterns required was computed by dividing the project area by the pattern area corresponding to each well spacing.

<u>Costs</u>

Costs common to the three injectant gas cases - 100% CO_2 , 87% N_2-13% CO_2 and 50% N_2-50% CO_2 – are listed in Table 2. The costs specific to each case are listed in Tables 3, 4 and 5, respectively. Terms listed in the tables are explained here:

Lease Acquisition Costs. A uniform distribution was used to model uncertainties in lease acquisition costs. Minimum and maximum values of $50.00 and $300.00 per acre were used.

CO_2 Capture Costs. This is the cost of separating CO_2 from the flue gas emitted by the power plant and compressing to pressures sufficient for pipeline transportation. A uniform distribution was used to model uncertainties in CO_2 capture costs. Minimum and maximum values of $1.00 and $2.00 per Mscf of CO_2 were used (Table 3).[1]

Injection Gas Pipeline Costs. The injection gas (pure CO_2 or mixed flue gas) pipeline CAPEX (Table 2) is computed based on a cost of $20,000/inch-mile[3] for the entire project, normalized to a pattern basis. A CO_2 injection pipeline OPEX of $0.01/Mscf was used for the 100% CO_2 injection studies,[3] as shown in Table 3. A flue-gas injection pipeline OPEX of $0.50 per Mscf was used for the 87% N_2 - 13% CO_2 flue gas studies,[2] as shown in Table 4. This cost includes particulate removal, dehydration and compression costs.[2] A uniform distribution between $0.50 and $1.00 per Mscf was used to model uncertainties in injection gas pipeline OPEX for the 50% N_2 - 50% CO_2 flue gas studies, as shown in Table 5. This higher cost implicitly includes some CO_2 capture costs, which were not included separately for this case, required to produce a 50% N_2 - 50% CO_2 mixture from flue gas.

Production Well Costs. The new production well CAPEX includes roads, locations, drilling, completion, stimulation, production equipment and flowlines.[3]

Gas Treatment and Compression Facility Costs. This is the capital cost of the gas treatment and compression facilities. It is computed for this project based on a cost of $84,613 (70,000 Euros) per well for 160-acre well spacing, as provided in Damen *et al.*[6]

Injected Gas Compression Costs. The injected gas (CO_2 or flue gas) compression OPEX is the cost of compressing the gas to the required wellhead injection pressure.[3]

Produced Methane Processing Costs. This includes the cost of separating methane from the other waste gases and compression. Nitrogen rejection cost for the flue gas injection studies is taken as $0.50 per Mscf of wellstream gas.[3]

Water Disposal Costs. Disposal operating costs include the cost to transport the water to the disposal well (either by gathering pipelines or trucking), the cost to inject the water, and the costs to maintain the injection well. Injection operating costs are estimated to be $0.40 per barrel.

Safety, Monitoring and Verification Costs. This includes estimated costs to ensure the proper implementation of the sequestration project.[3]

Economic results are presented in terms of the present value ratio indicator (ratio of net present value to investment). Economic results that are presented assume that the project is terminated at the economic limit (time at which the monthly net cash flow goes negative).

Economic Modeling Results

For this research, we conducted five separate simulation investigations, or cases. These cases are (1) CO_2 sequestration base case scenarios for 4,000-ft and 6,200-ft depth coal beds in the Lower Calvert Bluff Formation of east-central Texas, (2) sensitivity study of the effects of well spacing on sequestration, (3) sensitivity study of the effects of injection gas composition, (4) sensitivity study of the effects of injection rate, and (5) sensitivity study of the effects of coal dewatering prior to CO_2 injection/sequestration. We present revised economic modeling results in the following sections. The changes made to the economic model during this quarter widen the distributions of economic results but, overall, do not have a significant impact on the conclusions presented in previous reports.

Case 1: Base Case 1a (4,000-ft injection depth) and Case 1b (6,200-ft injection depth)

To assess reservoir performance during CO_2 sequestration in Lower Calvert Bluff (LCB) coals, we conducted probabilistic simulations (1,000 iterations), modeling simultaneous injection of 100% CO_2 and production of CH_4 under the base case operating conditions, in an 80-acre 5-spot pattern (40-acre well spacing). Reservoir simulation results for Case 1 were reported in the 2nd quarterly report of 2005.

The economic results for this study are presented in Fig. 1. Most of the probability lies in the negative NPV/I region, indicating 100% CO_2 injection is not economically feasible for these base cases with the ranges of gas prices and carbon credits investigated. NPV/I for Case 1a (4,000 ft) is usually less than that for Case 1b (6,200 ft). This is due primarily to decreased well construction costs for shallower well depths.

Case 2: Effects of well spacing on CO_2 Sequestration and ECBM

To determine the effects of well spacing on performance of coalbed reservoirs during CO_2 sequestration and ECMB production, we conducted probabilistic simulation modeling studies (1,000 iterations) of 100% CO_2 gas injection under the base case operating conditions for 80, 160, and 240-acre well spacings for the 6,200-ft depth base case. These simulation studies are denoted as Cases 2a, 2b, and 2c, respectively. Case 1b reported results of the 40-ac well spacing case. Reservoir simulation results for Case 2 were reported in the 2nd quarterly report of 2005.

The cumulative distribution functions for NPV/I for the different well spacings are shown in Fig. 2. Economic analysis of the 160-ac and 240-ac well-spacing cases were conducted for 30 yrs since the breakthrough times were significantly longer than 20 yrs. The economics improve with increasing well spacing, particularly at the upper end of the cumulative distribution functions, most likely due to lower capital expenditures and well operating costs associated with increasing well spacing. However, the economic results are still predominately negative for these cases with 100% CO_2 injection at 6,200 ft.

Case 3: Effects of injection gas composition on CO_2 sequestration and ECBM

To determine the effects of injection gas composition on performance of CO_2 sequestration and ECMB production in Wilcox coals in east-central Texas, we conducted probabilistic simulations, each consisting of 1,000 iterations, modeling injection of 50% CO_2-50% N_2 (Case 3a) and flue gas (13% CO_2-87% N_2, Case 3b) under the base case operating conditions, in an 80-acre 5-spot pattern (40-acre well spacing) for the 6,200-ft depth case. Reservoir simulation results for Case 3 were reported in the previous quarterly report.

Economic results from this study are presented in Fig. 3. The economic results improve significantly with addition of N_2 to the injection gas stream, although the economics are still predominately negative. The differences between Case 3a (87% N_2 - 13% CO_2) and Case 3b (50% N_2 - 50% CO_2) are small. The differences in economic performance between 100% CO_2 injection and the other two cases with N_2 in the injection gas are due primarily to (1) increased CO_2 capture costs for the 100% CO_2

injection case and (2) lower methane production and, thus, lower gross revenue for the 100% CO_2 injection case.

Case 4: Effects of injection rate on CO_2 sequestration and ECBM

To determine the effects of injection rate on performance of CO_2 sequestration and ECMB production in Wilcox coals in east-central Texas, we conducted deterministic simulation modeling studies of 100% CO_2 gas injection for the 6,200-ft depth base case (Case 1b) under two sets of operating conditions, base case operating conditions and conditions in which the pressure drop between injector and producer is reduced by 920 psi. Reservoir simulation results for Case 4 were reported in the previous quarterly report.

Case 1b was for the 40-ac well spacing case with the production well constrained at a constant bottom hole flowing pressure of 40 psia and the injection well constrained at a constant bottom hole injection pressure of 3,625 psia. A modified case with the production well constrained by a constant bottom hole flowing pressure of 500 psia and the injection well constrained by a bottom hole injection pressure of 3,165 psia was selected to model the effect of variable injection rate. Wells are secondarily constrained in the model by maximum gas production and injection rates of 3,530 Mcf/D.

Economic results from this study are presented in Fig. 4 and Tables 6 and 7. The effect of lowering the injection rate and the pressure drop between injector and producer on NPV/I is not significant for the cases investigated in this study.

Case 5: Effects of coal dewatering on CO_2 sequestration and ECBM

To determine the effects of dewatering the coals prior to CO_2 injection on performance of CO_2 sequestration and ECMB production in Wilcox coals in east-central Texas, we conducted deterministic simulation modeling studies of 100% CO_2 injection under the base case operating conditions for two production/injection schedules for the 6,200-ft depth base case. Reservoir simulation results for Case 5 were reported in the previous quarterly report.

To compare with the case in which injection and production start simultaneously (Case 1b), we modified this case to start CO_2 injection after 6 months and after 18 months of production. We performed deterministic sensitivity analysis for the most-likely, least-favorable, and most-favorable reservoir parameters.

Economics from this study are presented in Fig. 5 and Tables 8, 9 and 10. Dewatering the coals prior to CO_2 injection does not have a significant impact on economic performance of CO_2 sequestration and ECMB production.

Technology Transfer

As part of our technology transfer obligations for this project, results of these investigations were presented at the West Texas Geological Society Fall Symposium in October 25-28, 2005, in Midland, Texas, and at the Coal-Seq IV Forum held on November 9-10, 2005, in Denver, Colorado. An abstract was submitted and accepted for presentation at the 2006 SPE Gas Technology Symposium to be held in Calgary, Alberta, Canada on May 15-18, 2006.

CONCLUSIONS

Although changes made to the economic model this quarter widen the distributions of economic results, they do not significantly impact conclusions presented in previous reports. CO_2 sequestration volumes decrease and ECBM production increases with increasing N_2 content in the injected gas. The best economic performance is obtained with flue gas (13% CO_2-87% N_2) injection, compared to injection gas compositions with increasing amounts of CO_2.

Well spacing sensitivity studies for 100% CO_2 injection indicate that total volumes of CO_2 sequestered and methane produced on a unit-area basis do not change significantly with spacings up to 240 acres per well. The likelihood of project economic viability increases somewhat with increasing well spacing.

The economic conditions investigated in this study included gas prices ranging from $2/Mscf - $12/Mscf and CO_2 credits based on carbon market prices ranging from $0.05 to $1.58 per Mscf CO_2 ($1.00 to $30.00 per ton CO_2). Additional analysis indicated that CO_2 sequestration/ECBM projects will more likely be economically viable with gas prices and/or carbon market prices at the upper ends of these ranges investigated. These favorable economic conditions are not unattainable given recent gas price history and current carbon market prices in Europe. More favorable economic conditions, combined with the close proximity of many CO_2 point sources near unmineable coalbeds, could generate significant CO_2 sequestration and ECBM potential in Texas low-rank coals.

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6. Damen, K., Faaij, A., Van Bergen, F., Gale, J. and Lysen, E.; "Identification of early opportunities for CO_2 sequestration-worldwide screening for CO_2-EOR and CO_2-ECBM projects," Energy, 2005, v30, pp.1931-1952.

Table 1 - Economic Model Parameters		
Parameters	**Value**	**Units**
Federal Tax Rate	35	%
Discount Rate	10	%
Gas Price (1)	2.00, 4.00, 12.00	$/Mscf CH_4
Gas Price Escalation	3	%/yr
Texas Severance Tax	7.50	%
Net Revenue Interest (2)	75, 80	%
Carbon Market Price (2)	0.05, 1.58	$/Mscf CO_2
Net to Gross CO_2 Injection Ratio for CO_2 Sequestration Credits	70	%
Area of field	30,000	acres
Area of 5-spot pattern	80, 160, 320, 480	acres
(1) Triangular Distribution (2) Uniform Distribution		

Table 2 - Costs for 100% CO_2 , 87% N_2-13% CO_2 and 50% N_2-50% CO_2 Injection		
Item	**Cost**	**Units**
Lease Acquisition Costs (1)	50.00, 300.00	$/acre
Injection Gas Pipeline CAPEX	53.33	$/inch-mile (*)
New Injection Well CAPEX	100.00	$/ft
New Injection Well OPEX	1,500.00	$/month
New Production Well CAPEX	100.00	$/ft
New Production Well OPEX	1,500.00	$/month
Gas Treatment and Compression Facilities CAPEX	21,153.13	$ (*)
Produced Water Disposal	0.40	$/bbl
Safety, Monitoring and Verification	10,000.00	$/injector/yr
(1) Uniform Distribution (*) Cost computed for a single 80-acre pattern		

Table 3 - Costs for 100% CO_2 Injection Case		
Item	**Cost**	**Units**
CO_2 Capture Cost (1)	1.00, 2.00	\$/Mscf
CO_2 Pipeline OPEX	0.01	\$/Mscf
CO_2 Compression OPEX	0.30	\$/Mscf CO_2
(1) Uniform Distribution		

Table 4 - Costs for 87% N_2-13% CO_2 injection		
Item	**Cost**	**Units**
Injection Gas Pipeline OPEX	0.50	\$/Mscf of Injected Gas
Produced Methane Processing (Nitrogen Rejection)	0.50	\$/Mscf Wellstream

Table 5 - Costs for 50% N_2-50% CO_2 injection		
Item	**Cost**	**Units**
Injection Gas Pipeline OPEX (1)	0.50, 1.00	\$/Mscf of Injected Gas
Produced Methane Processing (Nitrogen Rejection)	0.50	\$/Mscf Wellstream
(1) Uniform Distribution		

Table 6. Effect of Injection Rate Case 4a: Pwf = 40 psi, BHIP = 3625 psi			
Scenario		**Mean NPV**	**Mean NPV/I**
1	Least favorable	(\$1,368,854.75)	-1.06
2	Most likely	(\$1,146,601.04)	-0.89
3	Most favorable	(\$403,293.99)	-0.31

Table 7. Effect of Injection Rate Case 4b: Pwf = 500 psi, BHIP = 3165 psi			
Scenario		**Mean NPV**	**Mean NPV/I**
1	Least favorable	($1,344,337.30)	-1.04
2	Most likely	($1,089,465.03)	-0.84
3	Most favorable	($536,889.46)	-0.416

Table 8. Effect of Dewatering Case 5: Simultaneous Injection and Production			
Scenario		**Mean NPV**	**Mean NPV/I**
1	Least favorable	($1,368,854.75)	-1.06
2	Most likely	($1,146,601.04)	-0.89
3	Most favorable	($403,293.99)	-0.31

Table 9. Effect of Dewatering Case 5 - Dewater After 18 mths			
Scenario		**Mean NPV**	**Mean NPV/I**
1	Least favorable	($1,322,042.12)	-1.02
2	Most likely	($1,125,873.33)	-0.87
3	Most favorable	($437,372.78)	-0.34

Table 10. Effect of Dewatering Case 5 - Dewater After 6 mths			
Scenario		**Mean NPV**	**Mean NPV/I**
1	Least favorable	($1,341,745.41)	-1.04
2	Most likely	($1,163,701.62)	-0.90
3	Most favorable	($380,621.02)	-0.29

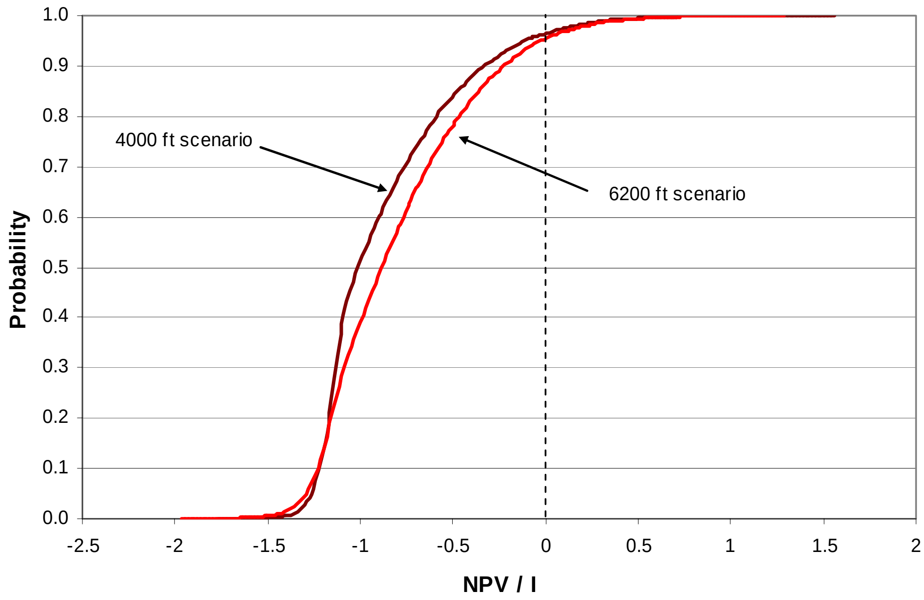

Fig. 1- Cumulative distribution functions of NPV/I for Case 1 (4000 ft and 6200 ft).

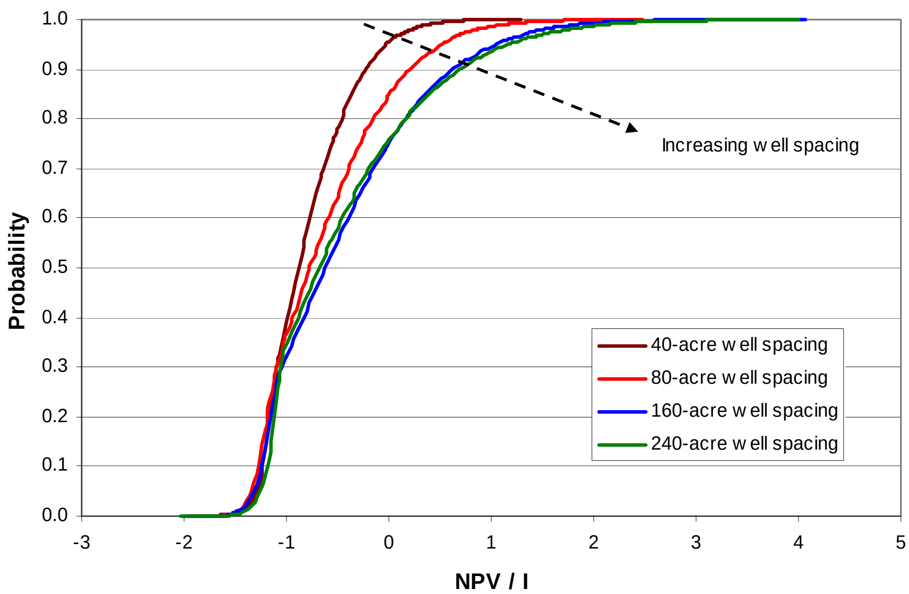

Fig. 2- Cumulative distribution functions of NPV/I for Case 2 (100% CO_2, 6200 ft).

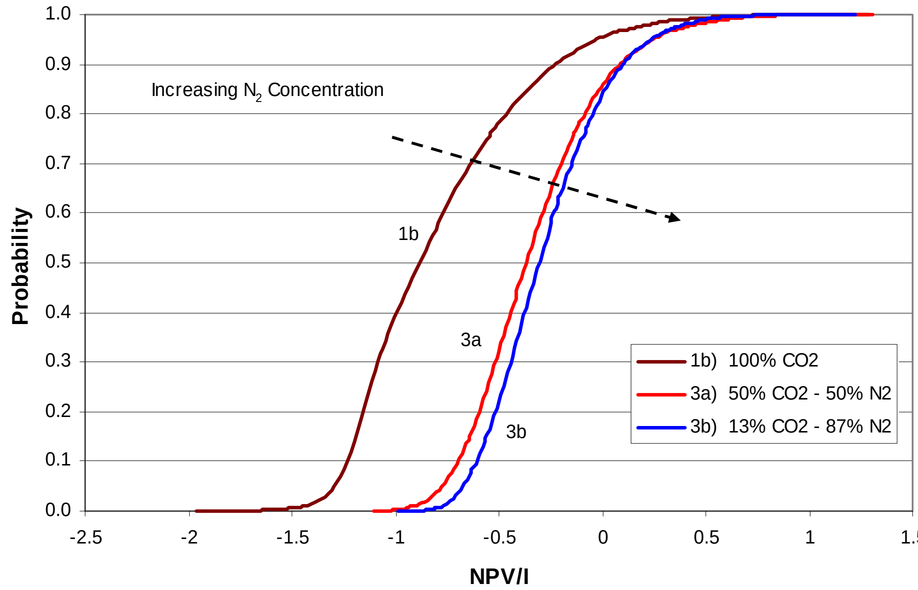

Fig. 3- Cumulative distribution functions of NPV/I for Case 3 (40-ac well spacing, 6200 ft).

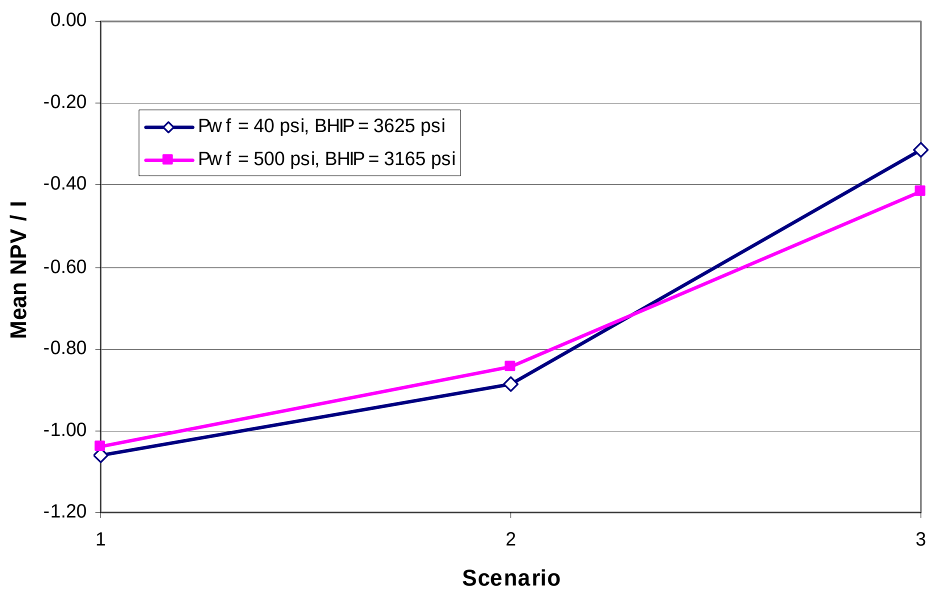

Fig. 4- Plot of NPV/I for different injection rate cases for (1) least-favorable, (2) most-likely and, (3) most-favorable reservoir property scenarios.

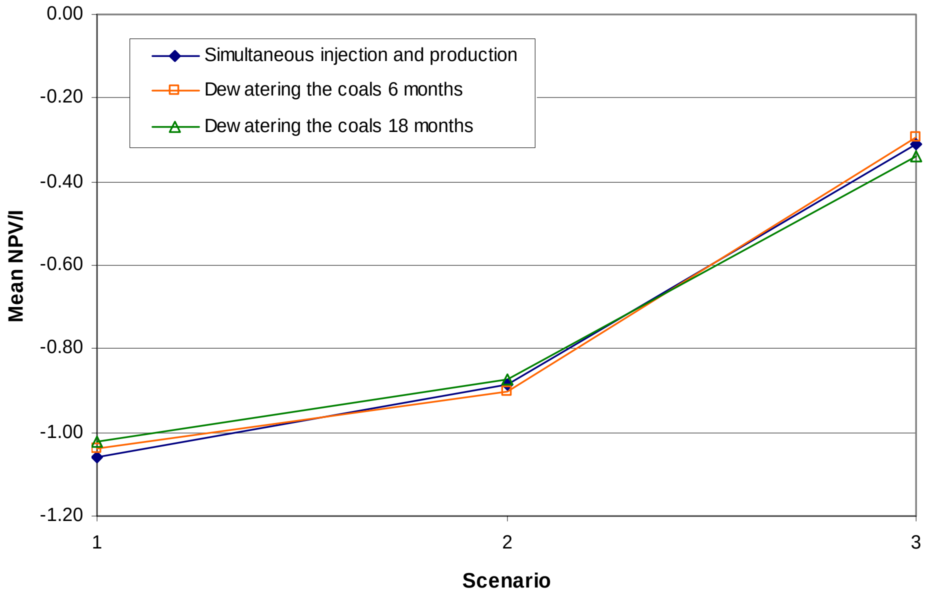

Fig. 5- Plot of NPV/I for different dewatering times prior to production for (1) least-favorable, (2) most-likely and, (3) most-favorable reservoir property scenarios.