Lookout Mountain Analysis
W. Thomas Goerold, Ph.D.
Specializing in environmental and natural resource issues

Powder River Basin Coalbed Methane Financial Model (PRB-CBM-FM)

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By Lookout Mountain Analysis
W. Thomas Goerold, Ph.D.
<tgoerold@lookoutmtn.com>

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314 Parkview Avenue • Golden, CO 80401 • (303) 526-2362

I. Objectives and Structure of this Study

This paper is a revision of a preliminary financial analysis of Powder River Basin (PRB) Coalbed Methane (CBM) operators. A previous paper was given before the University of Colorado Natural Resources Law Center conference on April 6, 2001. The ultimate objective of this and possible subsequent papers is to (1) construct representative models of different CBM operations throughout the PRB region, (2) examine costs of different water disposal options, and (3) compare the results of this financial model with other cost estimates from the U.S. EPA, the CBM industry, conservation groups, and other sources, and (4) construct a series of different project scenarios that will accurately illustrate the financial impact of a multitude of possible regulatory and other project actions. The resulting financial model, as described in this paper is termed the Powder River Basin Coalbed Methane Financial Model (PRB-CBM-FM).

Subsequent sections of this paper discuss data sources, financial model methodology, financial model assumptions, characteristics of different modeled PRB CBM regions, model results, conclusions, references, and finally, an appendix shows selected portions of the model.

II. Data Sources

Five major sources supplied data that were used to evaluate the costs and project structure of CBM operations throughout the Powder River Basin. They are; (1) A report by Morgan Stanley Dean Witter Research on Coal Bed Methane (4/10/00) (Morgan Stanley Dean Witter, 2000); (2) Several descriptive documents from the U.S. EPA on their website that give some economic parameters, assumptions, and basic proposed EPA financial model structures and scenarios (EPA, 2002); (3) A Report by Brian Hodgson of Marathon Oil that lays out in detail the costs of a number of water treatment scenarios for PRB CBM wells (Hodgson, 2001); (4) Two reports that were commissioned by the EPA that surveyed the PRB CBM operators on many economic aspects of CBM operations in that region. The first report (ERGa) was later revised and updated by a subsequent report (ERGb); Finally (5) Ron W. Pritchett, a hydrologist commissioned by one of the PRB CBM operators, prepared a report that exhaustively examined the geologic formations—from shallow to deep—to find possible candidate formations that would be able to receive quantities of water produced during the CBM de-watering and gas-production process and the costs associated with filling them with produced water (Pritchett, 2001).

III. Methodology

The financial model used in this study (PRB-CBM-FM) is based on a class of financial models called discounted cashflow (DCF) models. DCF models are probably the most commonly used tools used by companies, stock researchers, and others to evaluate the financial viability of different projects (as well as different scenarios within projects). It is very likely that most or all of the CBM operators in the Powder River Basin use DCF models to evaluate different coalbed methane project scenarios.

A DCF model implicitly recognizes the time value of money—a cost or revenue that occurs now is given more weight than a similar cost or revenue that occurs in the future. The further into the future that a cost or revenue occurs, the less the weight given to it by a DCF model. The basis for this differential weighting is explained by the observation that, for example, a dollar invested today will be worth more in five years than a dollar invested next year. So—a dollar in-hand today is worth more than a dollar in-hand tomorrow. Thus, the costs and revenues that occur today have a greater impact on overall project profitability than costs and revenues that occur further out into the future.

Another useful feature of a DCF model is that it can compare projects and scenarios that have very different patterns of costs and expenditures and evaluate them all on a common footing. For example, Project A may require that an investor pay $500 today to start a project that will return $150 in each of the next four years and $25 for each of the succeeding two years. Alternatively, Project B may need investments of $300 in each of the next two years that would yield returns of $125 in each of the following six years. Which project is the most attractive? DCF models assign weights, based on the timing of the costs and revenues. A discount rate, based primarily on what the firm must pay to acquire investment funds, is used to calculate the weightings of the costs and revenues. Then, a DCF model can look at the entire proposed project and calculate the "life-of-project" or annualized values for each of the project's cost or revenue categories.

In the above example, a DCF analysis could calculate annualized values for the revenue streams for each of the different projects. Also, one could use a DCF model to obtain annualized values for the cost streams. Even though they contain different values in different years, the annualized values for Project A can be directly compared to those of Project B. With a DCF analysis tool one can then critically evaluate the likely total financial viability of different projects, and can also compare different cost and revenue components to help determine the causes of different project financial viabilities.

IV. Assumptions

A. Regional Gas Fields Modeled - Two different regions are modeled by PRB-CBM-FM—the Eastern Region, and the Northern Region. These geographic sections are represented by the Fairway North, and Northern Production Area model scenarios, respectively. Collectively, these two regions host the large majority of PRB CBM production. This model assumes that all PRB projects occur in Wyoming. Montana PRB projects may show slightly different results.

B. Scale and Duration - The financial model described in this paper is constructed at the well level. That is, costs, revenues, and profits are calculated as they are produced from a single well. PRB CBM operators usually configure CBM operations so that a series of wells from contiguous regions tie into a single node (or "pod"). These pods then feed their gas into successively higher-pressured pipelines. Ultimately the gas produced from the PRB CBM is transported to gas marketing sites from Wyoming to Louisiana. These marketing sites then distribute the gas to the final end users (or to storage). PRB-CBM-FM model base cases assume that each well operates for 9 years. An alternative financial model scenario allows one to use a 15 year CBM well life.

C. Revenues - Revenues in the PRB-CBM-FM are modeled starting with an assumed price for gas delivered to a site in Louisiana called Henry Hub. Working backwards from the Henry Hub price, the PRB-CBM-FM deducts costs for (1) transportation from Cheyenne Hub (WY) to Henry Hub (LA), (2) "shrinkage" and fuel costs for powering the compressors that compress and transport gas from the wellhead and through various pipelines, and (3) adjustments for differences of the BTU content and impurities of the PRB CBM gas, as measured against national natural gas standards.

D. Costs - Costs are broken down as follows: (1) capital costs of constructing a well and the pro-rata portion of a pod (excluding water-disposal facilities); (2) capital costs of constructing the water disposal facilities; (3) costs of operating a well (excluding water-disposal facilities); (4) costs of operating water-disposal facilities; (5) costs of leasing land and payment of royalty rights to owners of the CBM; (6) severance tax payments to the State of Wyoming; (7) payment of incomes taxes to the U.S. Government and the State of Wyoming.

Collectively, with one exception, these are all of the costs that a typical PRB CBM operator will face during the CBM production process. In this preliminary stage of modeling, final reclamation costs are not calculated. Because the actual length of operations at a given CBM facility is based on changing costs and revenues that occur during the CBM operations, the actual shut-down date of each well is difficult to calculate. Also, under current law and practice, reclamation costs for these types of facilities are typically not large and therefore do not have a significant impact on overall profitability of CBM wells.

E. Profits - PRB CBM profits are calculated by subtracting project costs from project revenues during each year of operation. A convention of DCF models is that the discount rate (cost of obtaining investment funds for each firm) is considered to define a "normal profit." In this instance and in most economic applications, a normal profit is the minimum expected profit that is expected from CBM firms operating in the PRB. So, in addition to representing the firm's cost of obtaining investment funds, the discount rate also represents a firm's expected (or "normal") profit. In the PRB-CBM-FM I have used a discount rate of 10 percent.

Thus, if a firm earns a return on investment (ROI) of 10 percent, it has earned a normal profit. In this financial model, if a firm earns in excess of 10 percent, the excess is called an "above-normal" profit. One can think of the 10 percent rate as being a benchmark—if a project earns 10 percent or more, it fully covers the cost of obtaining the investment funds and can be considered a profitable project. Conversely, a project yielding an ROI of less than 10 percent is unprofitable because obtaining investment funds costs the firm 10 percent per annum.

F. Selected Gas Field Characteristics – Selected characteristics of the two gas fields are: (A) ultimate gas production in 9-year life: 0.418 billion cubic feet (bcf)-(Northern), and 0.364 bcf (East), (B) ultimate water production: 343,000 barrels-(Northern), and 854,000 barrels-(East), (C) well depth: 850 feet-(Northern), 1000 feet-(East), (D) well and pro-rata pod costs: $98,500-(Northern), $95,000-(East), (E) base case gas decline rate: 13 percent per annum-(Northern and East), (F) base case water decline rate: 50 percent per annum-(Northern and East), and (G) number of wells per pod: 8-(Northern and East).

G. Water Disposal Facilities Modeled – At this time the PRB-CBM-FM model features six different water disposal technologies (1) surface water disposal (data from ERGb), (2) shallow injection (data from ERGb), (3) deep injection (data from ERGb), (4) shallow injection (data from Hodgson), (5) deep injection (10% of produced water) combined with surface treatment (90% of produced water) (data from Pritchett), and (6) reverse osmosis (80% of produced water) combined with shallow disposal (20% of produced water) (data from Hodgson). Technical details pertaining to these water disposal techniques are beyond the scope of this paper. For additional details please refer to the referenced source of each water disposal technique.

V. Results

Two broad classes of scenarios were analyzed for each base case in the PRB-CBM-FM—(1) current gas price, and (2) breakeven gas price. The current gas price case uses a recent value for the Henry Hub (LA) gas price ($3.61 per thousand cubic feet [Mcf]) as an indicator of the profitability of each region's projects with the six different water disposal variants. The breakeven gas price varies the gas price needed for each region's projects to reach a 10 percent return on investment (ROI). A 10 percent ROI is considered the minimum rate of return needed for a project to be considered profitable.

By comparing the different ROIs returned by each region's projects under the current gas price scenarios, one can find the impact on overall project profitability of each of the six different water disposal options. One can find out the individual impact of any water disposal technique, or any other cost or revenue category on project profitability. If a project exceeds a 10 percent ROI, one can also calculate the "above-normal" profits that the project generates.

One might assume that all above-normal profits would be available for other purposes. For example, if under a particular scenario a project ROI is 15 percent, the additional profits above a "normal profit" of 10 percent might be available to pay for a more expensive water disposal technique.

A. Current Gas Price Scenario – Appendix A of this report shows PRB-CBM-FM (a) assumption section, (b) water disposal cost section, and (c) results section. Examples of these model elements are shown for an East region model run for a scenario embodying base case assumptions, current gas price, and surface water disposal.

Selected results of the East region model runs are shown in Table 1.

Table 1 – Return on Investment (ROI), PRB East Region, Base Case Assumptions, Current Gas Price

Water Disposal Techniques	Return on Investment	"Above-Normal" Profits (NPV)
1 - Surface Disposal (ERG data)	44 Percent	$158,414
2 - Shallow Injection (ERG data)	38 Percent	$137,735
3 – Deep Injection (ERG data)	21 Percent	$71,117
4 - Shallow Injection (Hodgson data)	36 Percent	$139,152
5 – Deep Injection + Surface Treatment (Pritchett data)	25 Percent	$95,510
6 - Reverse Osmosis + Shallow Injection (Hodgson data)	27 Percent	$104,822

Source: PRB-CBM-FM model runs, see individual references for additional details.

Table 1 assumes that each of these East PRB projects receives $3.61 per Mcf of gas produced. This gas price is relatively high by historical standards—although gas prices in 2001 reached levels more than double that value. Note that all projects exceeded a 10 percent ROI. And, as expected, the most profitable project used surface disposal techniques for produced water (project 1). PRB East model projects handle significantly more water than PRB Northern projects.

The 44 percent ROI for the surface water disposal indicates that "above-normal" profits of $158,414 exist (as expressed in present-day dollars or "net present value [NPV]). Expressed another way, if $158,414 in revenues was removed from the surface water project, the overall ROI of the project would drop to 10 percent. Or, expressed another way, if the project were required to use more expensive water disposal techniques, as much as $158,414 would be available for additional remediation, while still allowing for a minimum ROI of 10 percent.

Note that the least profitable project (project 3) uses deep injection water disposal techniques and results in an ROI of 21 percent and above-normal profits of $71,117. Comparing project 1 with project 3 shows that the net effect of using deep injection costs an additional $87,297 and lowers the ROI from 44 to 21 percent.

Other water disposal techniques fall in between these two extremes. In order of decreasing profitability, the projects use (A) surface disposal, (B) shallow injection (ERG data), (C) shallow injection (Hodgson data), (D) reverse osmosis + shallow injection (Hodgson data), (E) deep injection + surface treatment (Pritchett data), and (F) deep injection (ERG data).

Table 2 shows results for Northern PRB projects. PRB Northern project model runs show a very similar pattern to PRB East projects. The span of ROIs is smaller (20-38 percent for PRB Northern versus 21-44 percent for PRB East), but the profitability ranking of each water disposal technique is virtually identical. The only difference is that PRB Northern project 6 (reverse osmosis + shallow injection) is the third most profitable technique whereas PRB East project 4 (shallow injection) is the third most profitable technique.

Table 2 – Return on Investment (ROI), PRB Northern Region, Base Case Assumptions, Current Gas Price

Water Disposal Techniques	Return on Investment	"Above-Normal" Profits (NPV)
1 - Surface Disposal (ERG data)	38 Percent	$123,543
2 - Shallow Injection (ERG data)	36 Percent	$114,344
3 – Deep Injection (ERG data)	20 Percent	$59,099
4 - Shallow Injection (Hodgson data)	23 Percent	$75,040
5 – Deep Injection + Surface Treatment (Pritchett data)	22 Percent	$70,982
6 - Reverse Osmosis + Shallow Injection (Hodgson data)	31 Percent	$104,269

Source: PRB-CBM-FM model scenarios, see individual references for additional details.

Above-normal profits in the PRB Northern region projects range from $70,982 to $123,543 as compared to $59,099 to $123,543 for PRB East projects. Thus, under the current gas price scenario, PRB Northern projects are typically from 17 to 22 percent less profitable than analogous PRB East projects.

1. Cost Breakdown

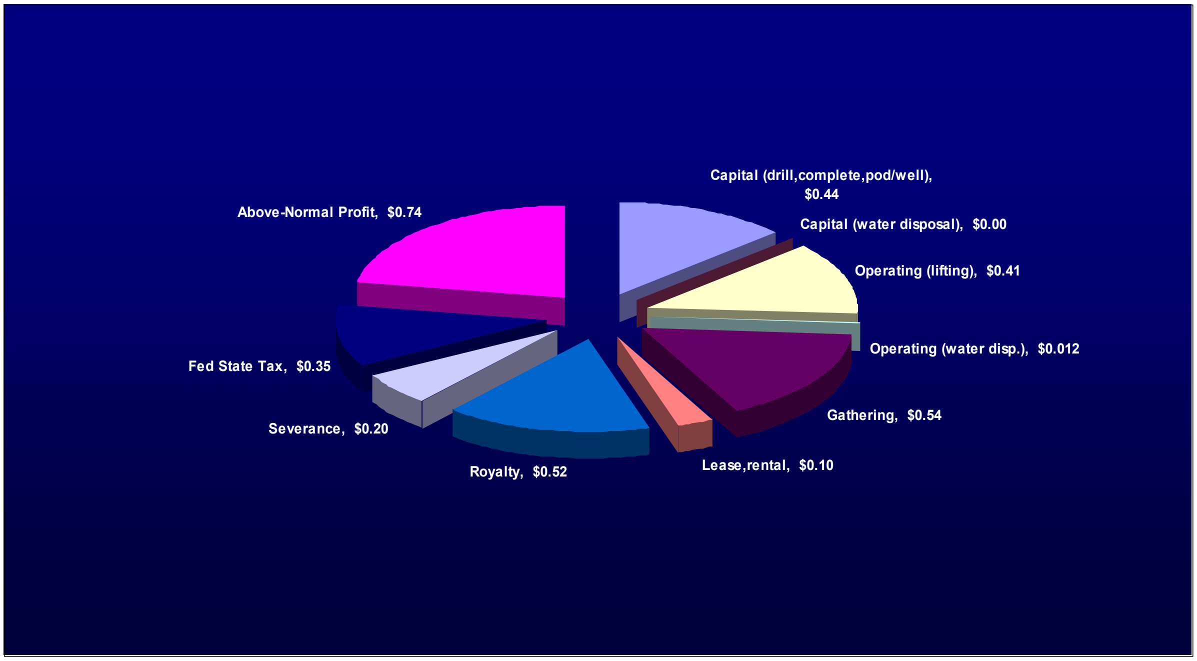
A. PRB East, Current Gas Price, Surface Water Disposal (ERG Data)

Figure 1 shows the breakdown of costs for a PRB East Region, Base Case, using surface disposal (water disposal option 1). Costs are shown as annualized values per Mcf of gas sold.

Revenues from each marketed Mcf of gas assume a recent Henry Hub gas price of $3.61. After losing gas lost from "shrinkage", and gas used to power pipeline compressors, revenues received amount to $3.31 per produced Mcf of gas, over the life of the project.

Cost calculations shown in Figure 1, starting with the 12 o'clock position, show the capital costs of building the well (exclusive of water disposal facilities) that amount to $0.44 per Mcf. Capital costs for constructing facilities for surface water disposal are negligible—they actually round down to $0.00. Operating costs of the methane well (lifting costs) (exclusive of water disposal) are $0.41 per Mcf. Water disposal operating costs amount to $0.012 per Mcf.

Figure 1 – Cost Breakdown of PRB East, Current Gas Price ($3.61), Surface Water Disposal



Source: PRB-CBM-FM model

Gathering costs are shown in the four o'clock position in Figure 1. These costs are associated with collecting produced gas from individual wells, transporting them to pods, and ultimately to successively larger pipelines. PRB East gathering costs in this scenario amount to $0.54 per Mcf.

Payments to the owners of the mineral and surface rights by coalbed methane operators total $0.62 per Mcf. Mineral severance taxes paid to the state of Wyoming and income taxes paid to Wyoming and the Federal Government total $0.55 per Mcf.

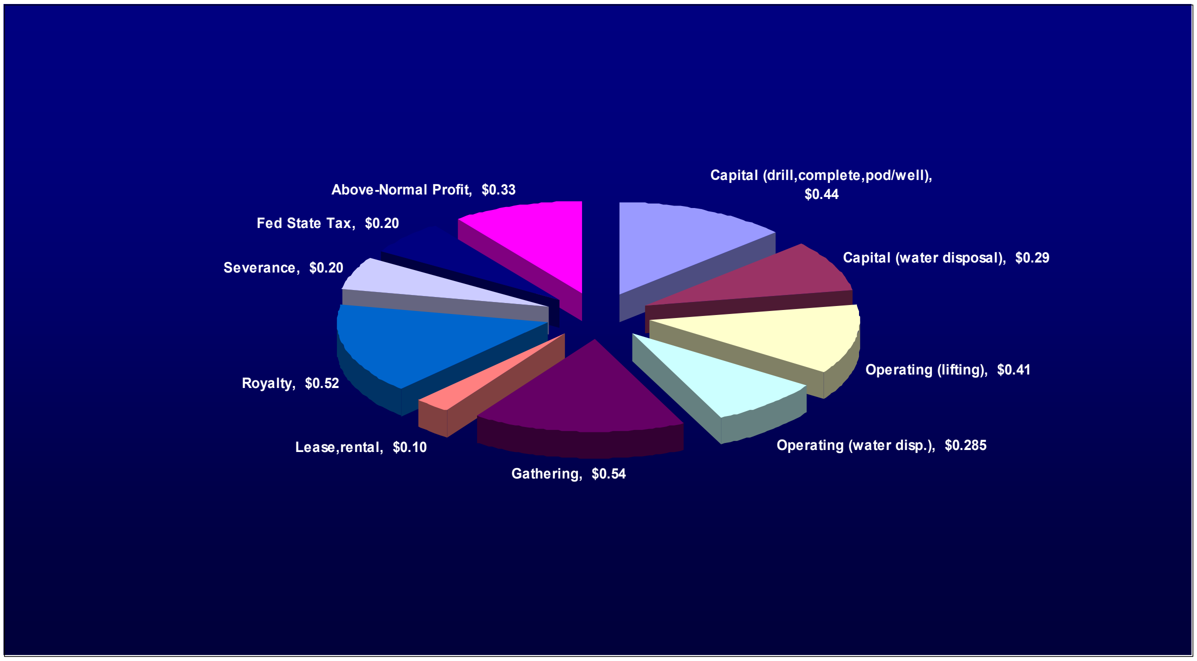
The final "piece of the pie", shown at the 10 o'clock position, is "above-normal profits." As explained previously in the text, above-normal profits are monies earned in excess of the assumed "normal" return on investment of 10 percent. In the scenario shown in Figure 1, above-normal profits amount to $0.74 per Mcf. Examined another way, if $0.74 per Mcf were removed from the project, the return on investment would drop from 44 percent to 10 percent.

B. PRB East, Current Gas Price, Deep Injection Water Disposal (ERG Data)

Figure 2 shows an almost identical PRB East project scenario—all assumptions remain the same as those shown in Figure 1 except that deep injection is used as a water disposal technique rather than surface water techniques (water disposal option 3 instead of water disposal option 1). This scenario represents the most costly water disposal option that is modeled in this study.

Return on investment drops from 44 to 21 percent due to the additional costs of deep injection of produced water. The revenues earned by the project on each increment of gas remain the same as those shown in scenario described in Figure 1.

Figure 2 – Cost Breakdown of PRB East, Current Gas Price ($3.61), Deep Injection (ERG Data)



Source: PRB-CBM-FM model

Costs of building the well and operating the well (exclusive of water disposal capital and operating costs) also remain the same—at $0.44 and $0.41 per Mcf, respectively.

But compared with the negligible capital costs incurred with surface disposal of water, deep injection capital costs amount to $0.29 per Mcf (according to data collected from the PRB industry by ERG representatives). And, deep injection operating costs amount to $0.285 per Mcf. The costs for disposing produced water by deep injection—$0.575 per Mcf, show an increase of more than 4000 percent compared with the $0.012 cost of using surface water disposal methods.

Gathering costs, surface and mineral payments, and severance taxes are identical in Figures 1 and 2. Lower profits levels, caused by deep injection of produced water, reduced the Wyoming and Federal income taxes by 43 percent--from $0.35 to $0.20 per Mcf. And, the above-normal profit decreased 55 percent--from $0.74 to $0.33 per Mcf.

B. Breakeven Gas Price Scenarios – Table 3 depicts the gas price needed to yield an ROI of 10 percent for the most- and the least-profitable water disposal techniques for both PRB East and PRB Northern projects.

Table 3 – Breakeven Gas Price Scenario, Base Case Assumptions, Selected PRB East and PRB Northern Projects

Water Disposal Techniques	Project Location	Breakeven Henry Hub (LA) Gas Price ($2002/Mcf)
1 - Surface Disposal (ERG data)	PRB East	$2.25
3 – Deep Injection (ERG data)	PRB East	$2.98
1 – Surface Disposal (ERG data)	PRB Northern	$2.47
3 – Deep Injection (ERG data)	PRB Northern	$3.05

Source: PRB-CBM-FM model runs, see individual references for additional details.

Interpreting the data in Table 3 shows that the Henry Hub (LA) gas prices needed to breakeven for all water disposal techniques ranges from $2.25 to $3.05—a range of $0.80 per Mcf. PRB Northern projects require a gas prices of from $0.22 (surface water disposal) to $0.07 (deep injection [ERG data]) more than analogous PRB East projects. Thus, the regional differences in water disposal techniques range tend to be relatively small. And, the cost differences between disposal techniques in all regions is about $0.80 per Mcf--about 22 percent of the current gas price of $3.61.

VI. Conclusions

Five major conclusions come from financial modeling using two regions to represent the large majority of current PRB CBM production. (1) Six water disposal techniques were modeled: (a) surface water disposal (ERG data), (b) shallow injection (ERG data), (c) deep injection (ERG data), (d) shallow injection (Hodgson data), (e) deep injection (10% of produced water) combined with surface treatment (90% of produced water) (Pritchett data), and (f) reverse osmosis (80% of produced water) combined with shallow disposal (20% of produced water) (Pritchett data). (2) Using a current gas price of $3.61 per Mcf, all water disposal techniques in all regions were profitable and yielded ROIs ranging from 20 to 44 percent that represent above-normal profits of about $59,000 to about $158,000 (NPV). (3) Regional variations between PRB East and PRB Northern regions were not large ($0.07 to $0.20 per Mcf). (4) Surface water disposal was the least costly option and deep injection the most costly, for both regions. Additionally, (5) Pritchett data shows that deep injection of 10 percent combined with surface treatment of 90 percent of produced water was significantly less costly than injecting all produced water. This produced-water-disposal technique shows promise because it minimizes the quantity of water that needs to be injected into costly deep wells and can produce significant amounts of drinking-water-quality water for beneficial consumption.

The Powder River Basin Coalbed Methane Financial Model (PRB-CBM-FM) described in this paper is a "work-in-progress." Feedback from government, industry, conservation, and other public and private sources will help to refine the assumptions, scenarios, and conclusions of this financial modeling effort.

VII. References

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Appendix A: Powder River Basin Coalbed Methane Financial Model, PRB East Region, Showing the (a) Assumptions Section, (b) Water Disposal Options Section, and (c) Results Section

A1. Assumptions Section

East-(Fairway North) Model

ASSUMPTIONS	
NYMEX Henry Hub Current Gas Price ($2002/Mcf)	$ 3.61
Basis Differential (Cost of Transportation of Rocky Mountain Gas to Marketing Hub [$/Mcf])	$ 0.30
BTU Cost Adjustment ($/Mcf as BTU adjustment cost)	$ -
Shrinkage/Compression/Field Use (%)	7.75%
Netback to Wellhead ($2002/Mcf)	$ 2.81
WY Severance Tax (% of sales) (1st 2 years @ 2% if <=360 Mcf/Day)	6.0%
Percentage Depletion Allowance (%)	15%
Depletion Type (0=Percentage Depletion,1=Cost Depletion)	0
Federal Income Tax Rate (%)	34%
WY Income Tax Rate (% of taxable income)	6.6%
Water Disposal (0=Surf. Dish.,1=Sh. Inj.,2=Deep Inj.,3=Sh Inj2,4=Deep Inj.+S.T.,5=RO + Sh. Inj.)	0
Independent Operator (60% costs expensed,1=Indep. Prod. [yes],0=Integ. Prod. [no])	0
Federal or Private Royalty (0=Private,1=Federal,2=Weighted Average)	2
PRB CBM Barrel of Oil Equivalent Multiplier (Mcf/Bbl)	5.56
Real Discount Rate	10%

EAST (FAIRWAY N) CHARACTERISTICS	
Avg. Well Depth (feet)	1,000
Peak Gas Prod (Mcf/Day)	170
Avg, Water Prod (Bbl/Day)	
Peak Water Prod (Bbl/Day)	750
Avg. Water Prod Volume (GPM)	
Peak Water Prod Volume (GPM)	22

Avg. Water Pump prior to production (months)	12
Avg. time to reach Peak Gas Prod (months)	12
First Gas Prod % of Peak (% of Peak Gas Prod)	75%
Ultimate Gas Recoveries (Bcf/well)	0.2-0.4
Typical gas decline rates/well (%/year)	13%
Typical water decline rates/well (%/year)	30%
Average Life of well (years)	9
Avg. Drilling & Completions Cost/Well	$ 95,000
Additional pod infrastructure costs	$ -
Avg. Total Well + Pro Rata Pod Costs (avg.)	$ 95,000
Gathering Fees per Mcf (includes treatment + transportation to Cheyenne Hub) ($/Mcf)	$ 0.50
Gas Lifting Costs per Month ($/Month)	$ 1,500
Land Costs ($, assuming 80 acre lease)	$ 32,000
Private Royalties (%)	20.0%
Federal Royalties (%)	12.5%
Weighted Average Royalty Rate (%)	15.65%
Number of Wells per Pod	8

A2. Water Disposal Options Section

WATER DISPOSAL OPTIONS	
Option 0	
Capital - Surface Water Disposal ($) (Source:ERG,1/02)	$ 300
O & M - Surface Water Disposal ($/BW) (Source:ERG,1/02)	$ 0.0040
Option 1	
Capital - Shallow Injection ($) (Source:ERG,1/02)	$ 6,250
O & M - Shallow Injection ($/BW) (Source:ERG,1/02)	$ 0.0450
Option 2	
Capital - Deep Injection ($) (Source:ERG,1/02)	$ 62,500
O & M - Deep Injection ($/BW) (Source:ERG,1/02)	$ 0.0950
Option 3	
Capital -Shallow Disposal Well ($/BW Capacity) (Source: Marathon Oil)	$ 28.57
O & M - New Shallow Disposal Well ($/BW) (Source: Marathon Oil)	$ 0.014
Piping Per Well (Miles) (Source: EPA)	0.06
Piping Cost ($/ft.) (Source: EPA)	$ -
Option 4	
Capital - 11,200 foot injection well / 25 wells	$ 58,480
Capital - 10% Deep Injection + 90% Surface Treatment ($/BW Daily Capacity) (Source: Caribou)	$ 9.75
Capital - 10% Deep Injection + 90% Surface Treatment ($/BW Daily Capacity) (Source: Caribou)	$ 6,384
O & M - 10% Deep Injection + 90% Surface Treatment ($/BW) (Source: Caribou)	$ 0.0400
Option 5	
Capital - Reverse Osmosis + WDW (20%) ($/BW Capacity) (Source: Marathon Oil)	$ 77.14
O & M - Reverse Osmosis + WDW (20%) ($/BW) (Source: Marathon Oil)	$ 0.033

2001,Marathon Oil (Brian Hodgson), "Current Options and Costs for Treating CBM Produced Water", in IPAMS workshop on coalbed methane, 10/15-10/16/01, (as cited in 2001,Feasibility Study: Water Placement related to Coalbed Methane Gas Production, Hanging Woman Basin Project, by Ron W. Pritchett for Michael J. Bowen, Caribou Land & LIvestock Montana, LLC.

A3. Results Section

9 YEAR PROJECT RESULTS Category	M 2002 Dollars	NPV M 2002 Dollars	Annualized 2002 Dollars Per Mcf
COST ITEMS			
Drilling, Completion, Pro-Rata Pod Capital Costs	$ 95,000	$ 95,000	$ 0.44
Chosen Additional Water Disposal Capital Cost	$ 300	$ 300	$ 0.00
Gas Lifting Cost	$ 144,000	$ 87,299	$ 0.41
Chosen Additional Water Disposal Operating Cost	$ 3,415	$ 2,571	$ 0.012
Gathering Cost	$ 181,859	$ 116,213	$ 0.54
Land Rental & Lease Cost	$ 32,000	$ 20,477	$ 0.10
Royalty Cost	$ 173,809	$ 111,069	$ 0.52
Severance Tax Cost	$ 66,636	$ 42,582	$ 0.20
Intangible Drilling Costs	$ 40,026	$ 40,026	$ 0.19
Depreciation (Capitalized Drilling Costs)	$ 55,274	$ 36,250	$ 0.17
Depletion Allowance	$ 166,590	$ 106,456	$ 0.50
Federal Income Tax Cost	$ 102,770	$ 63,462	$ 0.30
State Income Tax Cost	$ 19,950	$ 12,319	$ 0.06
Cost Total	$ 819,739	$ 551,290	$ 2.57
REVENUE ITEMS			
Gross Revenue	$ 1,313,018	$ 839,055	$ 3.91
BTU Adjustment	$ -	$ -	$ -
Shrinkage, Compression, Field Use Cost	$ (101,759)	$ (65,027)	$ (0.30)
Basis Differential (Rocky Mountain Gas Price Differential)	$ (100,659)	$ (64,324)	$ (0.30)
Revenue Total	$ 1,110,601	$ 709,705	$ 3.31

Above-Normal Profit	$ 290,862	$ 158,414	$ 0.74
		IRR	44%