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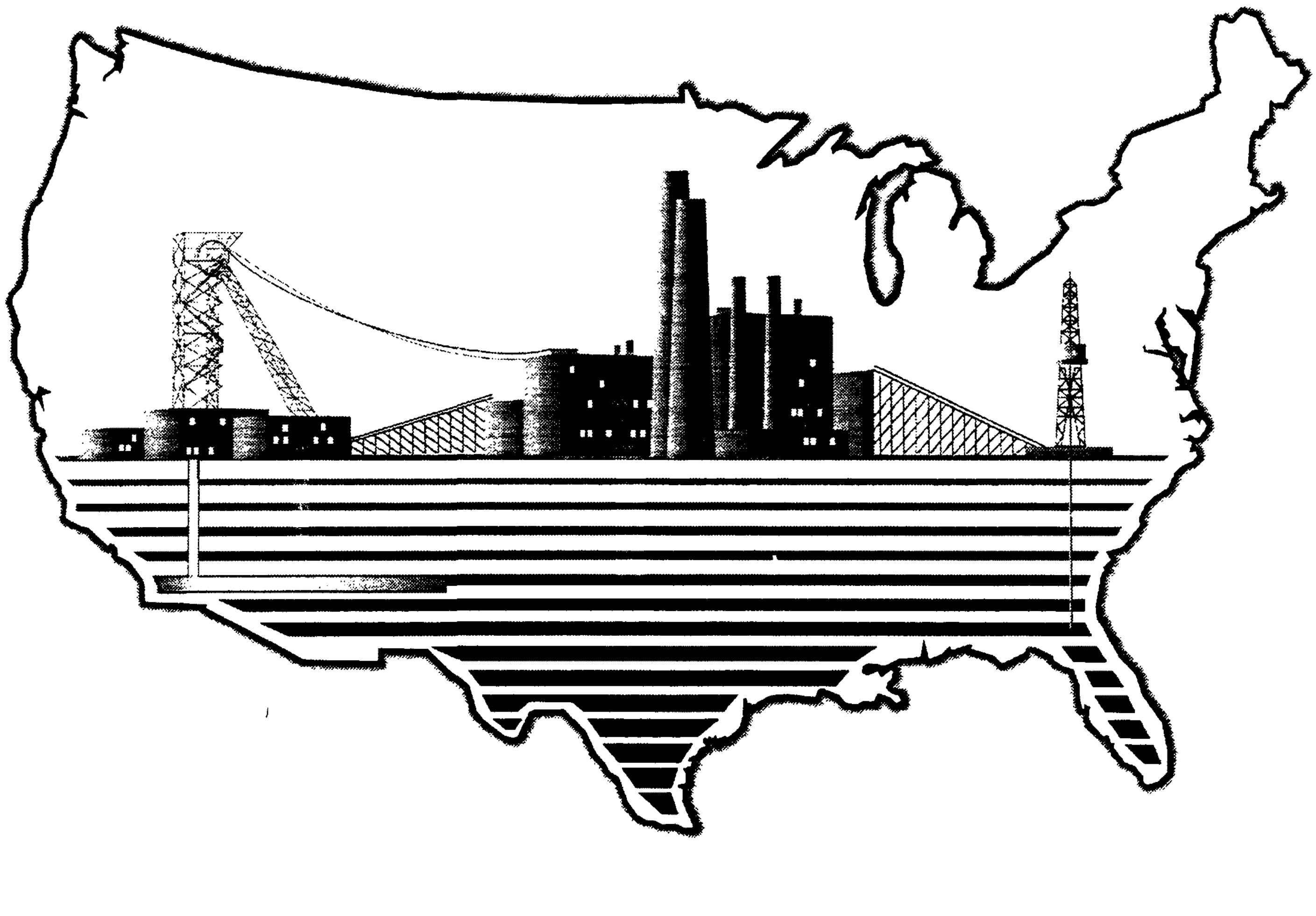
COALBED METHANE OUTREACH PROGRAM

Economic Assessment of the Potential for Profitable Use of Coal Mine Methane:

Case Studies of Three Hypothetical U.S. Mines



PUBLIC REVIEW DRAFT

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Introduction

Methane recovery and utilization can be a profitable undertaking for many large and gassy underground coal mines. Eleven U.S. mines have already developed projects involving the sale of recovered methane to pipeline companies, and at least one additional mine is using recovered methane to generate electricity. While pipeline projects have been developed at some of the gassiest mines in the U.S., there are at least 20 mines with high methane emissions (greater than 3 million cubic feet per day) that have not yet developed projects.

The purpose of this report is to provide information on the economics of methane utilization and to demonstrate that utilization can be profitable for mines with high methane emissions. This report presents economic assessments of the potential for profitable utilization of methane using three hypothetical "Sample Mines." Each Sample Mine case study presents an assessment of several different project options. While these three Sample Mines are hypothetical, their defining characteristics (e.g., level of methane emissions, annual coal production, degasification systems employed, and on-site electricity needs) are representative of the characteristics of gassy U.S. mines that have not yet developed utilization projects. Consequently, the economic results presented for these mines are indicative of results that could be achieved by developing a project at a very gassy mine.

The first section of this report presents an overview and a comparison of the relevant characteristics of each of the Sample Mines. The second section presents case studies showing how an evaluation of potential project options was performed for each mine. A general conclusions section follows the case studies. Appendix A of the report provides a detailed description of the assumptions that were used in the economic assessments of each of the Sample Mines. This Appendix may also be used by those interested in evaluating costs of methane recovery for specific projects. Appendix B provides a list of mines in the U.S. that have high methane emissions. Finally, the last section provides information about the Coalbed Methane Outreach Program.

The Coalbed Methane Outreach Program prepared these Sample Mine case studies in order to provide information to parties interested in developing coal mine methane projects or in purchasing gas or electricity from such projects. One of the main goals of this report is to facilitate the development of a dialogue between mine operators and other entities that may benefit by either investing in these projects or purchasing gas or electricity from them. By showing that a preliminary assessment indicates that there are opportunities for profitable utilization, this report may serve to stimulate interest in coal mine methane projects. Some of the groups that may benefit from reading these assessments include:

- Operators of large, gassy coal mines that are evaluating the possibility of developing utilization projects at their mines;
- Natural gas companies and pipeline companies interested in purchasing or transporting coal mine methane;
- Electric utilities interested in identifying greenhouse gas emissions reductions projects or in purchasing electricity from an environmentally beneficial project;

- Industries or large institutions with high demands for natural gas that may be interested in purchasing gas from mines;

- Communities in which gassy mines are located -- methane recovery projects create jobs that mining communities may be seeking; also, local governments could potentially attract new industries by demonstrating the significant cost savings resulting from the use of coal mine methane; and

- Gas recovery developers or private financiers who may be interested in providing funding for coal mine methane projects.

By showing that a range of utilization options can be profitable for gassy mines, this report should be of assistance to organizations evaluating the potential for specific coal mine methane projects. An earlier report published by the Coalbed Methane Outreach Program -- entitled "Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Draft Profiles of Selected Gassy Underground Coal Mines" -- was developed in order to assist organizations in identifying specific mines that are candidates for utilization projects.

While this report presents analyses for hypothetical mines, the Coalbed Methane Outreach Program is also preparing similar assessments for some of the mines identified in the Draft Profiles of Selected Gassy Underground Coal Mines report. Mine operators or other organizations interested in obtaining assistance in performing a site specific assessment should contact the Coalbed Methane Outreach Program. Information regarding the Program is provided in the last section of this report.

In summary, the Coalbed Methane Outreach Program developed this report in order to decrease the informational barriers constraining the development of coal mine methane projects that have the potential to be both profitable and environmentally beneficial. Each project at the largest and gassiest mines could result in over 2 billion cubic feet per year of methane emissions reductions (the equivalent of nearly one million tons of carbon dioxide per year). These reductions are roughly equal to the annual carbon dioxide emissions of 200,000 cars. By contributing to the dialogue between coal mine operators and others interested in methane recovery, this report should help to encourage the development of profitable emissions reductions projects.

Overview of Sample Mine Assessments

This report presents assessments for three Sample Mines, referred to as Mine A, Mine B, and Mine C. This overview describes the characteristics of each of the Sample Mines, presents the project options evaluated for each mine, and discusses the methodology used to determine the profitability of each option.

Characteristics of the Sample Mines

As mentioned previously, the Sample Mines shown in this report are hypothetical mines. However, while the mines are hypothetical, their defining characteristics (emissions, coal production, etc.) are representative of the relevant characteristics of gassy U.S. mines that have not yet developed utilization projects. Table 1 presents a comparison of the key characteristics assumed for each of the Sample Mines.

Table 1: Characteristics for Sample Mines

	Mine A	Mine B	Mine C
General Information			
Mining Method	Longwall	Longwall	Longwall
Remaining Lifetime	20 years	20 years	30 years
Annual Coal Production	2 million tons	3 million tons	2 million tons
Methane Emissions			
Emissions Per Ton	1000 cf/ton	2000 cf/ton	1500 cf/ton
Total Annual Methane Emissions	2.0 Bcf	6.0 Bcf	3.0 Bcf
Annual Ventilation Emissions	1.4 Bcf	3.0 Bcf	1.8 Bcf
Annual Degasification Emissions	0.6 Bcf	3.0 Bcf	1.2 Bcf
Degasification Method Employed	Gob Wells	Gob Wells and Horizontal Boreholes	Gob Wells
Degasification System Recovery Efficiency	30%	50%	40%
Percent of Degasification Emissions that is Pipeline Quality Gas (>95%)	5%	30% (70% from in-mine boreholes, 30% from gob wells)	25%
Utilization Information			
Distance to Pipeline	5 miles	1 mile	1 mile
Wellhead Gas Price	$1.50/mcf	$1.50/mcf	$1.50/mcf
Mine Electricity Price	5.5¢/kwh	4¢/kwh	4¢/kwh
Utility Avoided Cost	4.5¢/kwh	3¢/kwh	2¢/kwh
Nearby Industry or Institution with Large Natural Gas Needs?	No	No	Yes
Local Industrial End-user Gas Price	NA	NA	$5/mcf
Distance to Nearby Industry or Institution	NA	NA	5 miles
Annual Demand for Gas by Nearby Industry or Institution	NA	NA	0.36 Bcf
Coal-fired Thermal Dryer Used On-Site?	No	No	Yes
Current Price Received for Coal	NA	NA	$1.00/MMBTU

Mine A

Mine A is the smallest mine in terms of annual coal production (2 million tons) and annual methane emissions (2 billion cubic feet). The gob wells employed at the mine account for 30% of total methane emissions. In comparison to Mine B and Mine C, Mine A pays a relatively high average rate for its electricity (5.5 cents/kwh) and is located in the service territory of a utility that has a high avoided cost (4.5 cents/kwh).

Mine B

Of the three mines, Mine B has the highest total methane emissions (6 billion cubic feet). Mine B uses both horizontal boreholes and gob wells to remove large quantities of methane from the mine. Emissions from these degasification systems account for 50% of total methane emitted from the mine. Furthermore, of the methane emitted from degasification systems, 30% of the gas recovered has a methane content greater than 95% (which is considered to be suitable for sale to a pipeline company without requiring enrichment).

Mine C

Mine C has the same annual coal production as Mine A (2 million tons), but is significantly gassier (1,500 cf/ton as compared to 1,000 cf/ton for Mine A). Of the three mines, only Mine C employs a coal-fired thermal dryer. Furthermore, Mine C is the only mine that is assumed to be located near an industry that could potentially purchase recovered methane.

As shown in Table 1, all of the Sample Mines already have degasification systems in place. This analysis examines the possibilities for utilization of the methane recovered from these degasification systems.

Project Options Evaluated

The following project options were evaluated: 1) sale to a pipeline company, 2) power generation, 3) use in on-site facilities, and 4) sale to a local industry or institution with high demands for natural gas.

For the Sample Mines, two different types of pipeline sales projects were evaluated: 1) sale of only the portion of recovered gas that is suitable for pipeline sales without requiring enrichment, and 2) sale of all of the recovered gas, by enriching the off-spec gas to pipeline quality. For a pipeline project, the critical factors determining project profitability are the quantity and quality of gas produced, the proximity to a pipeline that can purchase the gas, and the price at which the gas can be sold. For coal mine methane projects, gas quality is a special concern. Mines that employ degasification methods that recover methane in advance of mining (e.g., vertical wells, horizontal boreholes) typically produce nearly pure methane that is suitable for pipeline sales. Degasification systems that recover methane post-mining (primarily gob wells), however, recover methane that is sometimes mixed with mine air. During the first few weeks of production, a gob well may produce nearly pure methane. Over time, however, substantial quantities of mine air may flow into the gob well and mix with the methane, rendering the gas unsuitable for pipeline sales. Once the methane content drops below 95%, enrichment is required before the gas can be sold to a pipeline company.

Enrichment consists of removing oxygen, nitrogen, and carbon dioxide from the gas stream. Enrichment of the gas may be expensive and tends to be profitable primarily at very large projects.

In comparison to pipeline projects, gas quality is not an issue for power generation projects, since gas with a methane content as low as 30% can be used to generate electricity. Two power generation projects are evaluated for the Sample Mines. The first power generation project consists of generating electricity to meet on-site needs and selling any electricity produced in excess of on-site needs to a utility. The second project involves generating just enough electricity to meet continuous on-site electricity demands. The primary factors in determining the profitability of a power generation project are the level of electricity that can be generated, the on-site electricity needs of the mine, the price the mine currently pays for electricity, and the buy-back rate offered by the local utility (the utility's avoided cost of generating electricity). Additionally, some utilities may charge high rates for emergency back-up power for projects that generate electricity to meet their on-site needs. The rates charged for back-up power can also have a significant impact on the profitability of a power generation project.

In addition to evaluating the potential for a pipeline sales or power generation project, the possibility of selling methane to a nearby industry or institution with large natural gas needs was also evaluated for Mine C. For this option, it was assumed that an industry could use the medium to high quality gas recovered from the mine. The primary factors determining the profitability of a local use project are the natural gas needs of the potential user, the distance between the user and the mine, the price at which the gas can be sold, and the cost of converting an existing fuel system to operate on coal mine methane.

Finally, the potential for use of the gas in an thermal dryer at a preparation plant was evaluated. Not all mines have thermal dryers. Furthermore, of the mines that have thermal dryers, some rely solely on electricity and not on coal as a source of fuel. Of the Sample Mines, only Mine C relies on a coal-fueled thermal dryer. Accordingly, this option is feasible only for this mine. The primary factors determining the profitability of using coal mine methane on-site are the price of the coal that would be displaced and the cost of converting the thermal dryer to operate on methane instead of coal.

Methodology

The Sample Mine characteristics shown in Table 1 were used to develop the basic assumptions used in the economic analysis of the various project options assessed for each mine. In addition to the specific characteristics shown in Table 1, general assumptions regarding likely project costs were used. These general assumptions are based on data from existing coal mine methane projects and are discussed in Appendix A.

For each of the options evaluated, a discounted cash flow analysis was used to determine the net present value of the project for the private mine operator. Additionally, the internal rate of return of the project was calculated. The discounted cash flow analysis consisted of several steps, including 1) calculating potential gas and electricity production, 2) estimating capital and operating costs incurred, and, 3) determining revenues and savings realized. After these calculations were made, annual project cash flows were determined over the lifetime of the project. These annual cash flows were then discounted to determine the net present value of each of the projects evaluated for the three different Sample Mines.

Detailed information on the specific assumptions that were used to estimate gas and electricity production and costs and revenues is shown in Appendix A. Additionally, the financial assumptions used in the discounted cash flow analysis, including the discount rate, inflation rate, and tax rate, are discussed in Appendix A.

The following case studies show the results of the discounted cash flow analysis for the range of projects evaluated at each of the Sample Mines.

SAMPLE MINE A
Two Profitable Options

Overview

A longwall mine, Mine A produces 2 million tons of coal per year and has 20 years of minable reserves. Mine A emits 1000 cubic feet of methane for every ton of coal mined (for a total of 2 billion cubic feet per year or about 5.5 million cubic feet per day). In addition to its ventilation systems, Mine A employs gob wells to improve safety and to increase coal productivity.

Production and Emissions Data	
Annual Coal Production	2 MM tons
Emissions Per Ton	1000 cf/ton
Total Annual Emissions	2.0 Bcf
Ventilation Emissions	1.4 Bcf
Degas Emissions	0.6 Bcf
Current Degas Method	Gob Wells
Degas % of Emissions	30%

The gob wells recover 0.6 billion cubic feet of methane per year (30% of total methane emitted from the mine). During the first few days of production, gob wells at the mine normally recover gas with a methane content greater than 95% (pipeline quality gas). After the first week, however, the methane content begins to decline steadily until, after about three months, the methane content is less than 40% and the vacuum pump used on the well is removed. Of the total gas recovered from gob wells, about 5% is pipeline quality.

Mine A is not located near any industries that have a high demand for natural gas. Furthermore, Mine A does not use a coal-fired thermal dryer at its preparation plant. Accordingly, potential utilization options involve either power generation or pipeline injection. The following specific utilization options were evaluated for Mine A:

Project 1: Electricity generation for on-site use and sale to a utility,
Project 2: Electricity generation to meet on-site continuous demand only,
Project 3: Pipeline injection using high quality gas that does not require enrichment,
Project 4: Pipeline injection using all recovered gas.

For all projects, a 20-year lifetime is assumed.

Power Generation

A prefeasibility assessment shows that Mine A can make a profit from using recovered methane to generate electricity for on-site use and sale to a utility (Project 1). The estimated NPV of such a project is $4.8 million, while the IRR is 18.1%. The prefeasibility assessment shows positive results for three reasons. First, Mine A currently is paying a high price for electricity (5.5¢/kwh). With annual electricity needs of 60 million kwh/yr, Mine A's annual cost of electricity exceeds $3.3 million. As shown in the tables at the end of this assessment, an on-site power generation project could reduce electricity purchases by 38 million kwh and result in annual savings of $2.1 million. The assessment assumes that the utility does not charge increased rates for any backup power purchased by the mine.

Power Generation Project 1	
NPV (million $)	$4.8
Internal Rate of Return	18.1%
Electric Capacity	5.8 MW
CO_2 Avoided (tons)	311,000
Mine Electricity Price	5.5¢/kwh
Utility Avoided Cost	4.5¢/kwh

The second factor contributing to the profitability of a power generation project is that the local utility has a relatively high buyback rate (4.5¢/kwh). Accordingly, Mine A can generate substantial revenues from selling "excess" electricity to the utility (electricity generated in excess of on-site needs occurs during times that the mine is not in full operation).

Mine A, continued

A final factor is that the electricity project could operate on the methane already recovered from gob wells. No additional degasification systems need to be installed and no processing of the gas is required. The project simply involves collecting gas that would otherwise be emitted from gob wells and moving it to a centrally located generator. The project utilizes 0.6 Bcf of gas per year to generate 50 million kwh/yr of electricity.

Mine A could also profit from developing a smaller power generation project (Project 2) that is designed to generate just enough electricity to meet the continuous on-site needs of the mine only. Project 2 would utilize only 58% of the recovered gas (0.348 Bcf/yr) to generate roughly 29 million kwh/yr of electricity.

Power Generation Project 2	
NPV (million $)	$2.5
Internal Rate of Return	17.4%
Electricity Generated	3.3 MW
CO_2 Avoided (tons)	176,000
Mine Electricity Price	5.5¢/kwh

The assessment shows that Project 2, with an NPV of $2.5 million and an IRR of 17.4%, is also a profitable alternative for Mine A. The NPV for Project 2, however, is considerably lower than the NPV for Project 1. The emissions reductions that would be achieved by this project are also significantly lower (the equivalent of 0.176 million tons of carbon dioxide for Project 2 as compared to 0.311 million tons for Project 1). One advantage of this smaller project, however, is that initial capital costs are significantly lower than for Project 1 ($4 million, as compared to $7.1 million for Project 1).

Pipeline Sales

With a transmission line located five miles from the mine, pipeline injection is also a possibility for Mine A. Two project options were evaluated: 1) use of only the methane recovered from gob wells that would not need to be enriched prior to pipeline injection; and 2) enrichment of the methane currently recovered from gob wells. These options are referred to as Project 3 and Project 4, respectively.

The economic assessment shows that Project 3 is not profitable. Since only 5% of the methane currently recovered from gob wells would not need to be enriched prior to sale to a pipeline, the revenues gained from the sale of this small portion of gas do not offset the high initial capital costs required for the project. For some mines, however, it may be possible to produce substantial volumes of pipeline quality methane from gob wells by blocking off certain areas of the longwall panel and through careful monitoring of the recovered gas. The analysis shows that, in order for Mine A to break even on this project, 75% of the gas recovered from gob wells (0.45 Bcf/yr) would need to have a high enough methane content so that it would not need to be enriched prior to pipeline injection. Alternatively, the mine could switch to a pre-mining degasification, which recovers nearly pure methane. Furthermore, two pre-mining degasification methods -- use of vertical wells and longhole horizontal boreholes -- can produce substantially higher volumes of methane than can gob wells, if drilled far enough in advance of mining.

The assessment further shows that Project 4 is not economically viable. Since only 5% of the methane released from the gob wells is of pipeline quality, enrichment will be required for 95% of the gas. The capital costs of the equipment needed for the enrichment process are high -- over $2 million dollars for a system that removes oxygen, nitrogen, and carbon dioxide. Additionally, construction costs for a pipeline between the mine and the existing pipeline are estimated to be $1 million (5 miles x $200,000 per mile). The annual revenues generated would not be enough to offset the high initial capital investment required for the project. In order to break even, Mine A would need to be able to sell the gas for $2.10/mcf, rather than $1.50/mcf.

Conclusion

The results of the analysis show that power generation projects are profitable for Mine A. While both Project 1 and Project 2 are economic, the NPV of Project 1 is much higher. Furthermore, Project 1 utilizes all of the recovered methane. A pipeline project does not appear to be feasible for Mine A, unless a pre-mining degasification system were to be installed in place of or in addition to the gob wells. As shown in the assessments for Mine B and Mine C, however, pipeline sales can be an extremely lucrative option for mines with higher emissions.

Mine A

Costs and Revenues for Power Generation (Project 1)

STANDARD CAPITAL AND OPERATING COSTS			
Coal Production	2,000,000		
Tonnage to Well Ratio	250,000		
Number of Wells Drilled Each Year	8		
Per-Well Annual Costs	Cost/Well	Wells/Year	Total Cost
Drilling Costs *	$0	8	$0
Gathering Lines from Well to Satellite	$12,000	8	$96,000
Total Per-Well Annual Costs	$12,000	8	$96,000
Standard Annual Operating Costs	Cost/Unit	# of Units	Total Cost
Salaries, Wages, Benefits **	$10,000	8	$100,000
Insurance	$30,000	1	$30,000
General Maintenance	$30,000	1	$30,000
Total Annual Operating Costs			$160,000
Initial Project Costs	Cost/Unit	# of Units	Total Cost
Wellhead Blower/Exhauster ***	$0	8	$0
Wellhead Knock-Out Separators ****	$2,000	8	$16,000
Wellhead Gas Flow/Quality Meters ****	$5,000	8	$40,000
Satellite Compressor Site Preparation	$70,000	1	$70,000
Satellite Compressor ($/HP x HP)	$600	320	$192,000
Safety Equipment	$100,000	1	$100,000
Total Initial Project Costs			$418,000

* Cost for incremental wells only.
** Minimum of $100,000 or $/well x # of wells value.
*** For incremental wells only, initial capital cost because blowers can be moved.
**** Considered initial capital cost because they can be moved.

COSTS/REVENUES FOR POWER GENERATION			
Per-Project Initial Capital Costs	$/Unit	# of Units	Total Cost
Line from SatComp to Generator ($/ft x ft)	$10	2000	$20,000
Generator ($/kw x kws)	$1,100	5,750	$6,324,932
Interconnection Costs	$300,000	1	$300,000
Total Per-Project Initial Capital Costs			$6,644,932
Annual Operating Costs	$/Unit	# of Units	Total Cost
Compression	$12,000	1	$12,000
Generator Operating Costs ($/kwh x kwh)	$0.01	50,369,455	$503,695
Total Annual Operating Costs			$515,695
Rev/Savings from Elec Use & Sales	$/kwh	kwh	Total Revenues
Savings from On-Site Use	$0.055	38,184,986	$2,100,174
Revenue from Sale to Utility	$0.045	12,184,468	$548,301
Total Revenue			$2,648,475

Mine A

Annual Cash Flows for Power Generation Project 1

Year	Initial Capital Cost Investment	Annual Revenue & Savings	Annual Operating Costs	Royalty Payments	Initial Capital Cost Depreciation	Income Before Taxes	Taxes Owed	Net Income (Accounting) (Purposes)	Total Cash Flow Of Project	Discounted Cash Flows Of Project
0	$7,067,736								($7,067,736)	($7,067,736)
1		$2,753,929	$802,463	$344,241	$353,387	$1,253,838	$501,535	$752,303	$1,105,689	$1,002,984
2		$2,864,086	$834,562	$358,011	$353,387	$1,318,127	$527,251	$790,876	$1,144,263	$941,559
3		$2,978,649	$867,944	$372,331	$353,387	$1,384,987	$553,995	$830,992	$1,184,379	$884,042
4		$3,097,795	$902,662	$387,224	$353,387	$1,454,522	$581,809	$872,713	$1,226,100	$830,174
5		$3,221,707	$938,769	$402,713	$353,387	$1,526,838	$610,735	$916,103	$1,269,490	$779,710
6		$3,350,575	$976,319	$418,822	$353,387	$1,602,047	$640,819	$961,228	$1,314,615	$732,425
7		$3,484,599	$1,015,372	$435,575	$353,387	$1,680,265	$672,106	$1,008,159	$1,361,546	$688,110
8		$3,623,982	$1,055,987	$452,998	$353,387	$1,761,611	$704,644	$1,056,967	$1,410,353	$646,568
9		$3,768,942	$1,098,226	$471,118	$353,387	$1,846,211	$738,484	$1,107,727	$1,461,113	$607,619
10		$3,919,699	$1,142,155	$489,962	$353,387	$1,934,195	$773,678	$1,160,517	$1,513,904	$571,092
11		$4,076,487	$1,187,842	$509,561	$353,387	$2,025,698	$810,279	$1,215,419	$1,568,806	$536,831
12		$4,239,547	$1,235,355	$529,943	$353,387	$2,120,861	$848,345	$1,272,517	$1,625,904	$504,690
13		$4,409,129	$1,284,770	$551,141	$353,387	$2,219,831	$887,933	$1,331,899	$1,685,286	$474,530
14		$4,585,494	$1,336,160	$573,187	$353,387	$2,322,760	$929,104	$1,393,656	$1,747,043	$446,226
15		$4,768,914	$1,389,607	$596,114	$353,387	$2,429,806	$971,922	$1,457,884	$1,811,270	$419,658
16		$4,959,670	$1,445,191	$619,959	$353,387	$2,541,134	$1,016,453	$1,524,680	$1,878,067	$394,715
17		$5,158,057	$1,502,999	$644,757	$353,387	$2,656,914	$1,062,766	$1,594,149	$1,947,535	$371,295
18		$5,364,379	$1,563,119	$670,547	$353,387	$2,777,327	$1,110,931	$1,666,396	$2,019,783	$349,300
19		$5,578,954	$1,625,643	$697,369	$353,387	$2,902,555	$1,161,022	$1,741,533	$2,094,920	$328,642
20		$5,802,113	$1,690,669	$725,264	$353,387	$3,032,793	$1,213,117	$1,819,676	$2,173,062	$309,235

Net Present Value of Project: $4,751,659
Internal Rate of Return: 18.1%

Real Discount Rate: 6%
Inflation Rate: 4%
Tax Rate: 40%
Royalties: 12.5%
Depreciation Method: Straightline

SAMPLE MINE B
Five Profitable Options

Overview

Mine B produces about 3 million tons of coal annually and has 20 years of minable reserves. This mine emits 2,000 cubic feet of methane for every ton of coal mined (for a total of 3 billion cubic feet per year or about 8.2 million cubic feet per day). In addition to its ventilation systems, Mine B employs both horizontal boreholes (drilled in advance of mining) and gob wells.

About 30% of the gas recovered by Mine B's degasification systems has a methane content greater than 95% (pipeline quality gas); 70% of this pipeline quality gas is recovered through pre-mining techniques, while 30% is recovered through gob wells. The remaining 70% of the methane recovered is medium to high BTU gas.

Production and Emissions Data

Coal Production	3 MM tons/yr
Emissions Per Ton	2000 cf/ton
Total Emissions	6.0 Bcf/yr
Ventilation	3.0 Bcf/yr
Degas	3.0 Bcf/yr
Current Degas Method	Gob Wells, In-Mine Boreholes
Degas % of Emissions	50%

Mine B does not have any large natural gas consumers nearby and does not use a thermal dryer on-site. Accordingly, only pipeline projects and power generation projects were evaluated. Specifically, the following five projects were assessed:

Project 1: Sale of High Quality Gas to a Pipeline,
Project 2: Sale of All Recovered Gas to a Pipeline,
Project 3: On-site Use and Sale of Electricity to a Utility,
Project 4: On-site Use of Electricity to Meet Continuous Demand,
Project 5: Combination of Project 1 and Project 4.

All projects are assumed to have a twenty-year lifetime.

Pipeline Sales

Since Mine B recovers both high quality and medium quality gas, two pipeline sales options were assessed. The first option (Project 1) involves selling only the recovered gas that would be suitable for pipeline sale without enrichment. The second option (Project 2) involves selling both the high quality gas and the lower quality gas, after it has been enriched to pipeline standards.

Pipeline Results

Wellhead Gas Price $1.50
Distance to Pipeline 1 mile

	Project 1	Project 2
NPV (MM $)	$6.7	$14.4
IRR	64.7%	44.7%
CH_4 Used (Bcf)	1.2	3.0
CO_2 (MM tons)	0.559	1.397

While 30% of the gas recovered at Mine B is suitable for sale to a pipeline without enrichment, an additional 10% of slightly lower quality gas can also be sold without being enriched if it is blended with the higher quality gas. Therefore, a total of 40% of the gas can be sold to a pipeline. The total amount of gas that would be recovered for pipeline sale is 1.2 Bcf/yr.

The results of the analysis show that Project 1 would be profitable for Mine B. The NPV is $6.7 million, and the IRR is 64.7%. Initial capital costs of the project are $1.2 million. Though only 40% of the gas is utilized, this project still achieves high emissions reductions. The equivalent of 0.6 million tons of carbon dioxide emissions are avoided every year.

The analysis shows that Project 2 would be profitable as well. Under Project 2, 100% of the recovered gas would be sold to a pipeline. Of this amount, 60% would require enrichment prior to pipeline injection. Although the capital costs of the equipment needed for the enrichment process are high -- over $2 million for a system that removes oxygen, nitrogen, and carbon dioxide -- these expenses are offset by the revenue generated from gas sales. Total initial capital costs are $4.2 million, while annual revenues are $3.6 million. The NPV of Project 2 is much higher than for Project 1 ($14.4 million, as compared to $6.7 million). The IRR for Project 2, however, is lower than for Project 1 (44.7%, as compared to 64.7%).

Power Generation

In addition to the two pipeline project options, two power generation options were also evaluated. The first such project (Project 3) involves using all of the recovered gas to generate electricity. Electricity produced would first be used to meet on-site needs. Any power generated above on-site needs would be sold to a utility. The second project (Project 4) involves generating electricity to meet continuous on-site electricity demand at the mine only. The advantages of this second project are that it requires a much smaller generator (and, thus, has lower initial capital costs) and that the mine would not need to sell power to a utility. For the power generation options, the analysis assumes that Mine B currently pays 4¢/kwh for electricity. The local utility has an avoided cost (buyback rate) of 3¢/kwh.

Power Generation Project Results

Mine Electricity Price	4¢/kwh
Utility Avoided Cost	3¢/kwh

	Project 3	Project 4
NPV (MM $)	$3.6	$0.2
IRR	11.6%	10.7%
CH_4 Used (Bcf)	3.0	0.5
CO_2 (MM tons)	1.397	0.237

Under Project 3, the project capacity is 28.7 MW, and 252 million kwh of electricity are generated each year. Of this 252 million kwh, roughly 90 million are used to meet on-site needs and 162 million are sold to a utility. Accordingly, annual electricity savings are about $3.6 million, and annual revenues from electricity sales are $4.8 million. Initial capital costs are high ($33.2 million), primarily as a result of the cost of the gas turbine ($1,100 per Kw installed capacity).

The NPV of Project 3 is $3.6 million, and the IRR is 11.6%. While this project is profitable, both pipeline projects are preferable since they have higher NPVs and IRRs. Furthermore, the initial capital costs of the project are much higher for Project 3 than for the pipeline projects ($33.2 million, as compared to $1.2 million for Project 1, and $4.2 million for Project 2). Since 100% of the recovered gas would be utilized, the emissions reductions achieved by this project are identical to those achieved under pipeline Project 2 -- 3.0 Bcf/yr of methane (1.397 million tons of carbon dioxide equivalent).

In comparison Project 3, the second power generation project (Project 4) -- use of electricity to meet continuous on-site demands only -- has significantly lower initial capital costs ($5.8 million, as compared to $33.2 million). The initial capital costs for this project, however, are still higher than for both pipeline projects. Under Project 4, annual savings realized are $1.7 million.

The results of the analysis show that Project 4 is also a profitable option. The NPV is $0.2 million, and the IRR is 10.7%. However, since both the NPV and IRR are lower than for Project 3 and for both pipeline sales options, this project appears less preferable.

Combination Project

In addition to the options discussed above, Mine B could undertake a combined project consisting of Project 1 (sale of high quality gas to a pipeline) and Project 4 (use of electricity to meet on-site continuous needs). Since pipeline sales Project 1 uses 40% of the recovered gas and power generation Project 4 requires 17% of the gas, the total gas utilized would be 57% (1.7 Bcf/yr). Total emissions avoided would be the equivalent of 0.796 million tons of carbon dioxide. Assuming that many of the collection costs and gathering costs would not need to be duplicated for both projects, the initial capital costs of the project are $6.7 million. Based on the results of the analysis, such a combination project would be economically beneficial for Mine B, with an NPV of $9.3 million and an IRR of 25.3%. The NPV of this project is not as high as that of pipeline Project 2, but is higher than the other options.

Combination Project Results	
NPV (million $)	$9.3
IRR	25.3%
Methane Used	1.7 Bcf
CO_2 Avoided (tons)	0.796 MM
Initial Capital Costs (million $)	$6.7

Mine B
Results for Profitable Options

Project	Percent of Recovered Gas Utilized	Annual Amount Used Bcf CH_4	Emissions Avoided million tons CO_2	Initial Capital Cost million $	NPV	IRR
1. Sale of High Quality Gob Gas to Pipeline	40%	1.2	0.559	$1.2	$6.7	64.7%
2. Sale of All Recovered Gas to a Pipeline, Enrichment Required	100%	3.0	1.397	$4.2	$14.4	44.7%
3. Electricity Generation for On-site Use and Sale to a Utility	100%	3.0	1.397	$33.2	$3.6	11.6%
4. Electricity Generation to Meet Continuous On-Site Needs Only	17%	0.5	0.237	$5.8	$0.2	10.7%
5. Combination of Project 1 and Project 4	57%	1.7	0.796	$6.7[1]	$9.3[1]	25.3%

[1] The sum of the initial capital costs for pipeline projects 1 and 4 is higher than the capital costs for the combined project due to economies of scale that result from developing a larger project. Annual operating costs for the combined project are also somewhat lower than the sum of the annual operating costs for the individual projects. Accordingly, the NPV for the combined project is higher than the sum of the NPVs for the individual projects.

Conclusion

For Mine B, at least five utilization projects are profitable -- two pipeline projects, two power generation projects, and one combined pipeline and power generation project. The NPV of the pipeline project involving sale of all recovered gas (Project 2) has the highest NPV, followed by the combined pipeline injection and power generation project (Project 5). Project 1 has the lowest initial capital costs

($1.2 million) and the highest internal rate of return. Project 2 and Project 3 utilize all of the recovered gas and therefore have the highest avoided emissions (3.0 Bcf/yr).

The analysis for Mine B shows that a wide range of projects may be profitable at a particular mine. Furthermore, under certain circumstances, combined projects that feature more than one use of the gas can also be feasible. Finally, the results for the pipeline projects show that large emissions reductions may be achieved for a relatively low initial capital investment.

Mine B

Costs and Revenues for Pipeline Project (1)

(Sale of High Quality Gas Only -- No Enrichment)

Standard Collection Costs			
Coal Production	3,000,000		
Tonnage to Well Ratio	250,000		
Number of Wells Drilled Each Year	12 [rounded to integer]		
Per-Well Annual Costs	Cost/Well	Wells/Year	Total Cost
Drilling Costs *	$0	12	$0
Gathering Lines from Well to Satellite	$12,000	12	$144,000
TOTAL Per-Well Annual Costs	$12,000	12	$144,000
Standard Annual Operating Costs	Cost/Unit	# of Units	Total Cost
Salaries, Wages, Benefits **	$10,000	12	$120,000
Insurance	$30,000	1	$30,000
General Maintenance	$30,000	1	$30,000
TOTAL Annual Operating Costs			$180,000
Initial Project Costs	Cost/Unit	# of Units	Total Cost
Wellhead Blower/Exhauster ***	$0	12	$0
Wellhead Knock-Out Separators ****	$2,000	12	$24,000
Wellhead Gas Flow/Quality Meters ****	$5,000	12	$60,000
Satellite Compressor Site Preparation	$70,000	1	$70,000
Sales Compressor Site Preparation	$70,000	1	$70,000
Ancillary Equipment	$100,000	1	$100,000
TOTAL Initial Project Costs			$324,000

* Cost for incremental wells only.
** Minimum of $100,000 or $/well x # of wells value.
*** For incremental wells only, initial capital cost because blowers can be moved.
**** Considered initial capital cost because they can be moved.

Costs Specific to Pipeline Utilization			
Per-Project Initial Capital Costs	Cost/Unit	# of Units	Total Cost
Satellite Compressor ($/HP x HP)	$600	660	$396,000
Sales Compressor ($/HP x HP)	$600	330	$198,000
Pipeline Lateral ($/mile x miles)	$200,000	1	$200,000
Dehydrator, Processor	$40,000	1	$40,000
Meter Run	$20,000	1	$20,000
TOTAL Per-Project Initial Capital Costs			$854,000
Annual Operating Costs for Pipeline Sales	$/unit	Units	Total Cost
Compression (assumes 2 units)	$12,000	2	$24,000
Dehydration (assumes 1 unit)	$3,000	1	$3,000
TOTAL Annual Operating Costs			$27,000
mcf Gas Sold to Pipeline (No Enrichment)	1,113,276		
Revenue from Pipeline Sales	$/mcf gas	mcf Gas	Total Revenue
Revenue Based on Wellhead Gas Price	$1.50	1,113,276	$1,669,914
TOTAL Revenue	$1.50	1,113,276	$1,669,914

Mine B

Gas Production for Pipeline Sales

Gas Production for Project 1	
Methane Recovered (cf/yr):	1,200,000,000
Compressor Loss Calculations	
HP Requirements for Satellite Compressor	660
HP Requirements for Sales Compressor	330
Compressor Loss Ratio (CF/BHP HR)	10
Gas Used to Fuel Satellite Compressor (cf/yr)	57,816,000
Gas Used to Fuel Sales Compressor (cf/yr)	28,908,000
Production Adjusted for Compressor Loss	
Gas for Pipeline Sales (No enrichment)	1,113,276,000

Gas Production for Project 2	
Methane Recovered (cf/yr):	1,800,000,000
Compressor Loss Calculations	
HP Requirements for Satellite Compressor	990
HP Requirements for Sales Compressor	490
Compressor Loss Ratio (CF/BHP HR)	10
Gas Used to Fuel Satellite Compressor (cf/yr)	86,724,000
Gas Used to Fuel Sales Compressor (cf/yr)	42,924,000
Gas Used in Enrichment Process (cf/yr)	400,884,480
Production Adjusted for Compressor Loss and Shrinkage (cf/yr)	
Gas for Pipeline Sales (assuming enrichment)	1,269,467,520

SAMPLE MINE C
Five Profitable Options

Overview

Mine C is a longwall mine with annual coal production of 2 million tons and a remaining lifetime of approximately 30 years. Total annual emissions are 3 Bcf, of which 1.8 Bcf (60%) are emitted from ventilation systems and 1.2 Bcf (40%) are emitted from degasification systems (gob wells). Of the methane emitted from the gob wells, 25% has not been mixed with significant quantities of mine air and, therefore, would be suitable for sale to a pipeline without requiring enrichment. The remaining gas would require enrichment prior to pipeline injection, but would also be suitable for power generation, sale to an industrial user, or use on-site.

Production and Emissions Data

Annual Coal Production	2 MM tons
Emissions Per Ton	1500 cf/ton
Total Annual Emissions	3.0 Bcf
Ventilation Emissions	1.8 Bcf
Degas Emissions	1.2 Bcf
Current Degas Method	Gob Wells
Degas % of Emissions	40%

Mine C is located only one mile from an existing pipeline that could transport the gas recovered at the mine. Additionally, an industry that could purchase 0.36 Bcf/yr of recovered methane is located 5 miles from the mine. Finally, Mine C uses a coal-fired thermal dryer that may be retrofitted for methane use. An economic assessment of the data for Mine C shows that there are five different profitable options for utilization of the methane currently recovered from degasification systems.

Pipeline Sales

Two different options involving the sale of gas to a pipeline were evaluated: 1) sale of the higher quality gob gas that would not require enrichment; and 2) sale of all recovered methane (both high quality and lower quality gas). The analysis shows that both of these options would be profitable.

Pipeline Results

Wellhead Gas Price $1.50
Distance 1 mile

	Project 1	Project 2
NPV (MM $)	$0.1	$3.0
IRR	11.2%	18.3%
CH_4 Used (Bcf)	0.30	1.20
CO_2 (MM tons)	0.144	0.559

The first option requires a relatively low initial capital cost of $0.7 million. The NPV for the project is $0.1 million, and the IRR is 11.2%. As with Mine B, the results indicate that, for some large and gassy mines, pipeline projects that involve the sale of only a small portion of the total amount of methane emitted can be profitable. Annual emissions reductions associated with this project are equivalent to 0.14 million tons of carbon dioxide.

The second option involves selling both the higher quality gas and the lower quality gas (after it has been enriched) to a pipeline. This option results in a higher capital cost ($3.2 million) than does the first option due to the $2.1 million cost of purchasing the enrichment equipment. Additionally, larger compressors will be needed for the project to handle the higher volumes of gas. The NPV for the project, however, is also much higher ($3 million as compared to $0.1 million), and the IRR is 18.3%. The results show that projects requiring gas enrichment can still be very profitable. Finally, emissions reductions associated with this project are also much higher than for the first project. Since all of the gas is utilized, the emissions reductions are the equivalent of avoiding the emission of 0.559 million tons of carbon dioxide.

Sale to Local Industry

Sale to Local Industry Results	
NPV (million $)	$5.7
Internal Rate of Return	40.3%
Methane Used	0.36 Bcf
CO_2 Avoided (tons)	0.168 MM
Gas Sales Price	$3.75/mcf
Distance to Industry	5 miles

Although not feasible for Mines A and B, the sale of gas to a nearby industrial user is a possibility for Mine C. The economic assessment assumes that Mine C is located 5 miles from an industry that could purchase 0.36 Bcf/yr of recovered methane. The analysis further assumes that the user would pay for any necessary retrofitting of its fuel systems to operate on coal mine methane if the mine would sell gas at a price 25% lower than the local industrial gas price ($5/mcf). Accordingly, the assessment assumes that the user would pay $3.75/mcf for the gas.

The results of the economic assessment show that sale of recovered methane to a local industrial user would be very profitable for Mine C. The NPV of the project is $5.7 million, and the IRR is 40.3%. The initial capital costs required for such a project are $1.5 million. Of the $1.5 million, $1 million is associated with the cost of constructing the pipeline from the mine to the user. While the industry is assumed to be located five miles from the mine, a potential customer could be much further from the mine and the project would still be profitable; the break-even distance for the project is 36 miles.

Use In Thermal Dryer

Use in Thermal Dryer Results	
NPV (million $)	$0.02
IRR	10.4%
Methane Used	0.48 Bcf
CO_2 Avoided (tons)	0.223 MM
Savings from Replacing Coal Use	$1/ MMBTU

Mine C is the only one of the sample mines that uses a coal-fired thermal dryer as part of its preparation plant facilities. A few U.S. mines reportedly have been able to retrofit their thermal dryers to operate on recovered methane instead of coal. In order to evaluate the potential for substituting recovered methane for coal in the thermal dryer, the analysis assumes that Mine C uses one ton of coal for every 150 tons of coal processed in the thermal dryer. Annual fuel requirements for the thermal dryer at Mine C would be about 13,300 tons of coal, or 347 billion BTUs per year. Accordingly, 0.48 Bcf/yr of methane would be required, which represents 40% of the total amount of gas that could be recovered from the mine degasification system.

For the analysis, the cost of converting the thermal dryer to operate on coal mine methane is $750,000. Furthermore, the market value of coal replaced with recovered methane is assumed to be $1/MM BTU.

Despite the high conversion cost, the project would be profitable. The analysis shows that the NPV is $0.02 million, and the IRR is 10.4%. The annual emissions avoided as a result of the project are the equivalent of 0.22 million tons of carbon dioxide.

Power Generation

The following assumptions were used to determine whether power generation would be a profitable project for Mine C. First, though the analysis assumes that the mine's lifetime will be 30 years, a 20-year project lifetime was used because the analysis also assumes that the generator will have a lifetime of 20 years. The mine electricity price is assumed to be 4¢/kwh; the utility avoided cost is 2¢/kwh. Finally, the assessment assumes that a gas turbine would be used to generate electricity and that the heat rate of the generator would be 11,000 BTUs/kwh.

Power Generation Results
(On-site Use and Sale)

Mine Price ¢/kwh	Avoided Cost ¢/kwh	NPV MM$	IRR
4	2	< 0	--
4	3	$1.6	11.8%
5	2	$2.6	12.6%

The project would generate about 100 million kwhs/year, of which 58 million kwhs/yr would be used to meet on-site needs and 42 million kwhs/yr would be sold to a nearby utility. The maximum capacity of the project would be 11.5 MW. Based on these assumptions, power generation would not be a profitable project for Mine C. The high initial capital cost required for the project ($13.6 million) would not be offset by the revenues and savings achieved.

While the results were not profitable assuming a mine electricity price of 4¢/kwh and a utility avoided cost of 2¢/kwh, increasing either of these prices by one cent results in a profitable project. Assuming a mine electricity price of 4¢/kwh and an avoided cost of 3¢/kwh results in a project NPV of $1.6 million and an IRR of 11.8%. Similarly, assuming a mine electricity price of 5¢/kwh and an avoided cost of 2¢/kwh leads to an NPV of $2.6 million and an IRR of 12.6%.

Finally, the analysis examined the possibility of developing a smaller project that would be designed to meet only the continuous on-site electricity needs of the mine. The advantages of such a project are that a smaller generator would be used, no utility interconnection costs would be included, and all electricity generated would be valued at the mine's electricity price. The results showed that the NPV for the project would be negative, assuming a mine electricity price of 4¢/kwh. However, at a mine electricity price of 5¢/kwh, the project would have a positive NPV of $1.5 million and an IRR of 14.8%.

Based on the assumptions for Mine C, the power generation projects do not appear profitable. If the utility avoided cost or the mine price for electricity were higher, however, power generation would be profitable.

Combination Project

Finally, the analysis examined the feasibility of combining the three projects that did not utilize all of the recovered methane: 1) sale of high quality gas to a pipeline; 2) sale to a nearby industrial user; and 3) use in the thermal dryer. For this combination project, it was assumed that many of the initial capital costs would not vary regardless of the amount of gas produced. For example, the compressor-site preparation costs would remain fairly constant even though the size of the compressors would increase for a combination project. Furthermore, other costs (such as for wellhead gas flow meters) would be the same regardless of the amount of gas recovered. Accordingly, the initial capital costs

Combination Project Results

NPV (million $)	$10.4
IRR	25.6%
Methane Used	1.14 Bcf
CO_2 Avoided (tons)	0.531 MM
Initial Capital Costs (million $)	$3.0

required for the combination project were significantly lower than the sum of the initial capital costs for the three projects individually.

The assessment showed that a combination project would be the most profitable for the mine. The NPV of the project would be $10.4 million, and the IRR would be 25.6%. Together, the three projects would utilize 95% of the recovered methane. Emissions reductions achieved would be the equivalent of 0.53 million tons of carbon dioxide.

Conclusion

In summary, the results of the economic assessment show that Mine C has at least five profitable options for utilizing methane: 1) sale of only high quality gas to a pipeline; 2) sale of all gas to a pipeline by enriching the lower quality gas; 3) sale of gas to a nearby industry; 4) use of the gas in an on-site thermal dryer; and 5) a combination project consisting of options 1), 3), and 4). The results show that the combination project is the most profitable (with a NPV of $10.4 million), followed by the sale of gas to a nearby industry ($5.7 million) and the sale of all recovered gas to a pipeline ($3 million).

Mine C
Results for Profitable Options

Utilization Option	Percent of Recovered Gas Utilized	Annual Amount Used Bcf CH_4	Emissions Avoided MM tons CO_2	Initial Capital Cost MM $	NPV MM $	IRR
1. Sale of High Quality Gob Gas to Pipeline, No Enrichment	25%	0.30	0.144	$0.7	$0.1	11.2%
2. Sale of All Gas to a Pipeline, Enrichment Required	100%	1.20	0.559	$3.2	$3.0	18.3%
3. Sale to Nearby Industry	30%	0.36	0.168	$1.5	$5.7	40.3%
4. Use in Thermal Dryer	40%	0.48	0.223	$1.2	$0.02	10.4%
5. Combination of #1, #3, and #4	95%	1.14	0.531	$3.0[1]	$10.4	25.6%

[1] The sum of the initial capital costs for projects 2, 3, and 4 is higher than the capital costs for the combined project due to economies of scale that result from developing a larger project. Annual operating costs for the combined project are also somewhat lower than the sum of the annual operating costs for the individual projects. Accordingly, the NPV for the combined project is higher than the sum of the NPVs for the individual projects.

Mine C

Results for Combination Project

STANDARD COLLECTION AND OPERATING COSTS			
Coal Production	2,000,000		
Tonnage to Well Ratio	250,000		
Number of Wells Drilled Each Year	8 [rounded to integer]		
Per-Well Annual Costs	Cost/Well	Wells/Year	Total Cost
Drilling Costs *	$0	8	$0
Gathering Lines from Well to Satellite	$12,000	8	$96,000
TOTAL Per-Well Annual Costs	$12,000	8	$96,000
Standard Annual Operating Costs	Cost/Unit	# of Units	Total Cost
Operating Cost of Satellite Compressor	$12,000	1	$12,000
Dehydration, Processing	$3,000	1	$3,000
Salaries, Wages, Benefits **	$10,000	8	$100,000
Insurance	$30,000	1	$30,000
General Maintenance	$30,000	1	$30,000
TOTAL Annual Operating Costs			$175,000
Initial Project Costs	Cost/Unit	# of Units	Total Cost
Wellhead Blower/Exhauster ***	$0	8	$0
Wellhead Knock-Out Separators ****	$2,000	8	$16,000
Wellhead Gas Flow/Quality Meters ****	$5,000	8	$40,000
Satellite Compressor Site Preparation	$70,000	1	$70,000
Ancillary Equipment	$100,000	1	$100,000
TOTAL Initial Project Costs			$226,000

* Cost for incremental wells only. Cost based on degas cost% specified.
** Minimum of $100,000 or $/well x # of wells value.
*** For incremental wells only, initial capital cost because blowers can be moved.
**** Considered initial capital cost because they can be moved.

Incremental Costs/Revenues for Pipeline Sales Project (Using 20% of the Gob Gas that is Nearly Pure Methane)			
Per-Project Initial Capital Costs	Cost/Unit	# of Units	Total Cost
Satellite Compressor ($/HP x HP)*	$600	160	$96,000
Sales Compressor Site Preparation	$70,000	1	$70,000
Sales Compressor ($/HP x HP)	$600	80	$48,000
Pipeline Lateral ($/mile x miles)	$200,000	1	$200,000
Dehydrator, Processor	$40,000	1	$40,000
Meter Run	$20,000	1	$20,000
TOTAL Per-Project Initial Capital Costs			$474,000
Annual Operating Costs for Pipeline Sales	$/unit	Units	Total Cost
Sales Compressor Operating Cost	$12,000	1	$12,000
TOTAL Annual Operating Costs			$12,000
Revenue from Pipeline Sales	$/mcf gas	mcf Gas	Total Revenue
Revenue Based on Wellhead Gas Price	$1.50	278,976	$418,464
TOTAL Revenue	$1.50	278,976	$418,464

* Incremental HP and cost needed in order to sale gas to a nearby industry.

Mine C

Results of Combination Project, Continued

Incremental Costs/Revenues for Project Involving Sale of Gas to Nearby Industry			
Per-Project Initial Capital Costs	Cost/Unit	# of Units	Total Cost
Line to Nearby User ($/mile x miles)	$200,000	5	$1,000,000
Dehydrator for Off-Site Sale	$40,000	1	$40,000
Satellite Compressor*	$600	200	$120,000
Add. Compressor: Off-Site Sales	$600	100	$60,000
SitePrep for Additional Compressor	$70,000	1	$70,000
TOTAL Per-Project Initial Capital Costs			$1,290,000
Annual Operating Costs for On-Site/Local Use	$/Unit	# of Units	Total Cost
Add. Sales Compressor	$12,000	1	$12,000
TOTAL Annual Operating Costs			$12,000
Revenue/Savings	$/mcf gas	mcf Gas	Total Revenue
Revenue: Gas Sales to Local Users	$3.75	342,480	$1,284,300
TOTAL Revenue			$1,284,300

* Incremental HP and cost needed in order to sale gas to a nearby industry.

Incremental Costs/Revenues for Using Gas in an On-Site Thermal Dryer			
Per-Project Initial Capital Costs	Cost/Unit	# of Units	Total Cost
Conversion Cost: PPlant Coal Replace	$750,000	1	$750,000
Line to On-site Facilities ($/ft x ft)	$10	2000	$20,000
Satellite Compressor ($/HP x HP)*	$600	260	$156,000
TOTAL Per-Project Initial Capital Costs			$926,000
Revenue/Savings	$/mcf gas	mcf Gas	Total Revenue
Savings: PrepPlant Coal Displacement	$1.00	457,224	$457,224
TOTAL Revenue			$457,224

* Incremental HP and cost needed in order to sale gas to a nearby industry.

Conclusion

This report demonstrates that the utilization of methane currently emitted from degasification systems could be profitable for several different types of mines. Moreover, several different types of projects may be feasible at a particular mine. The specific findings of the report are as follows:

Power Generation

- Coal mine methane power generation projects can generate substantial levels of electric capacity. The level of electric capacity that could be generated at the sample mines ranges from 5.8 MW (Mine A) to 28.7 MW (Mine B).

- Power generation projects can be a profitable option for utilizing recovered methane. Despite very different characteristics, both Mine A and Mine B showed the potential to make a profit from power generation projects.

- The profitability of a power generation project is extremely sensitive to the assumed mine electricity price and the utility avoided cost. For example, a power generation project is not profitable for Mine C when a mine electricity price of 4¢/kwh and a utility avoided cost of 2¢/kwh are assumed. However, increasing either the mine electricity price or the utility avoided cost by 1¢/kwh results in a very profitable project.

- Though Mine A produces significantly less gas than do Mines B and C, a power generation project is lucrative for Mine A because of the relatively high rates assumed for the mine electricity price (5.5¢/kwh) and the utility avoided cost (4.5¢/kwh).

- In comparison to pipeline projects, power generation projects require higher initial capital investment due to the high cost of installing gas turbines (on the order of $1100/kW). This means that a project may have relatively high NPVs but lower IRRs compared to pipeline and local use projects.

- Smaller power generation projects that are designed to generate electricity just to meet the continuous on-site needs of coal mines are also cost-effective. These smaller projects have significantly lower initial capital costs, because a smaller turbine is used. For the sample mines, however, these smaller projects were not as profitable as the projects involving generation of electricity for on-site use and off-site sale.

Pipeline Injection

- The sale of recovered methane to a pipeline may be a very lucrative option for mines with high methane emissions. This analysis examined the following two types of pipeline sales projects: 1) sale of high quality gas that would not require enrichment; and 2) sale of all gas recovered from a degasification system, with enrichment required for lower quality gas. For Mines B and C, both pipeline alternatives are profitable.

- The results for Mines B and C show that, for very large and gassy mines, the sale of a small portion of recovered gas can still result in a profitable project. For Mine B, 40% of the recovered gas could be sold to a pipeline without requiring enrichment. For Mine C, only 25% of the gas was assumed to be suitable for sale to a pipeline without enrichment.

- For both Mine B and Mine C, pipeline projects that included enrichment of lower quality gas were more profitable than the projects that did not utilize the lower quality gas. Accordingly, the results show that enrichment of gob gas may be a profitable option for some mines. Moreover, these projects result in larger emissions reductions than do projects that do not utilize the lower quality gas.

- For both Mine B and Mine C, the pipeline projects were more lucrative than were the power generation projects. These results are due to the low mine electricity prices and utility avoided costs assumed for these mines, as well as the close proximity of the mines to an existing pipeline.

- For Mine A, however, neither the sale of only high quality gas nor the enrichment of low quality gas was profitable. At the relatively low gas price that was assumed in this analysis ($1.50/mcf), Mine A did not produce enough gas to offset the initial capital costs of the project.

Local Use

- The sale of gas to a nearby industry or institution with a high demand for natural gas can be a very profitable way of utilizing recovered gas. This analysis assumes that a local industrial or institutional consumer would be willing to purchase recovered coal mine methane gas at a price 25% less than the existing industrial end-user rate. Based on this assumption, local use projects can generate large revenues, due to the high industrial end-user gas prices charged in many regions.

- The key factors determining whether a local use project will be profitable are the potential user's annual demand for natural gas and the distance between the mine and the user.

- In this assessment, only Mine C is assumed to have an industrial user located in close proximity. For Mine C, even though it is assumed that the nearby industrial user can only purchase 30% of the recovered methane and that the user is five miles from the mine, a project would still be very profitable.

- While local use projects appear to be extremely profitable, many mines may not be located near facilities that have large natural gas demands. For these mines, it may be worthwhile to identify industries or institutions that would be willing to relocate near the mine-site to take advantage of the low-cost energy.

Use in a Thermal Dryer

- This assessment shows that it may be profitable for a mine to switch from using coal in a thermal dryer to using recovered coal mine methane.

- The economics of switching from a coal-fired to a gas-fired thermal dryer were evaluated for Mine C. For this mine, even though a high conversion cost is assumed, the project was still shown to be profitable (the NPV was $0.02 million).

- At Mine C, about 40% of the recovered methane was utilized in the thermal dryer.

Combined Projects

- Projects that involve more than one utilization option can also provide a significant source of revenue for the mine. At Mine B, a project involving 1) sale of high quality methane to a pipeline and 2) use of lower quality methane to generate electricity to meet continuous on-site needs results in a NPV of $9.3 million and an IRR of 25.3%.

- At Mine C, a project involving 1) the sale of gas to a pipeline, 2) sale of gas to an end-user, and 3) use of gas in an on-site thermal dryer, results in a NPV of $10.4 million and an IRR of 25.6%. Under this combined approach, 95% of the recovered gas is utilized.

Emissions Avoided

- For all mines, large emissions reductions were achieved. Several types of projects evaluated at each of the mines involved utilization of all of the methane recovered from the degasification systems. For these projects, emissions reductions achieved ranged from 0.311 million tons of CO_2 equivalent at Mine A to 1.397 million tons at Mine B.

- Several options evaluated did not utilize the full amount of methane currently emitted from degasification systems at the sample mines. The portion of recovered gas that was utilized ranged from 17% (for an electricity project solely to meet continuous on-site needs at Mine C) to 40% (for a project involving sale of high quality methane at Mine B). Even though only a portion of the gas was used, these projects still resulted in large emissions reductions. For Mine B, utilizing 17% of the recovered methane yields emissions reductions equivalent to 0.5 million tons of carbon dioxide. Utilizing 40% of the methane recovered at Mine B results in emissions reductions equivalent to 0.2 million tons of carbon dioxide. Projects that combined one or more of these utilization options achieved much higher emissions reductions.

In conclusion, the analysis has shown that methane recovery and utilization projects can be profitable for mines with very different characteristics. Furthermore, several different types of projects may be feasible for an individual mine. The preferred project will depend on the quantity and quality of the recovered gas, the relative gas and electricity prices, initial capital costs, and other site-specific factors. In all cases, methane utilization projects can lead to very large emissions reductions.

APPENDIX A

CALCULATIONS AND ASSUMPTIONS USED IN THE ANALYSIS

This Appendix provides a detailed description of the steps used to perform the discounted cash flow analysis of the potential for profitable methane recovery and utilization at the Sample Mines evaluated in this report. Specifically, for each step in the analysis, this Appendix provides information on:

1) The equations/formulas used in the analysis;
2) The assumed values used in the equations; and
3) The sources used to develop the equations and assumptions.

In addition to describing the assumptions used in the discounted cash flow analysis for the Sample Mines, this Appendix should be useful to anyone desiring to evaluate the economics of utilizing coal mine methane.

The Appendix is divided into the following five sections: 1) Methane Emitted and Recovered, 2) Gas and Electricity Production and On-Site Energy Needs, 3) Capital and Operating Costs, 4) Revenues Generated and Savings Realized, and 5) Financial Assumptions. Throughout this Appendix, Sample Mine A is used to demonstrate how project costs and revenues and a net present value are estimated for the mines evaluated in the report. The table below shows the basic characteristics for Sample Mine A.

Sample Mine A Characteristics	
Coal Production:	2.0 million tons/yr
Ventilation Emissions:	1.4 Bcf/yr, 3.84 MMcf/d
Degasification Emissions	0.6 Bcf/yr, 1.64 MMcf/d
Total Emissions	2.0 Bcf/yr, 5.49 MMcf/d
Degasification Systems Used:	Gob Wells
Mine Electricity Price	$0.055/kwh
Utility Avoided Cost	$0.045/kwh
Local Industrial End-User Gas Price	$3/mcf
Distance to Local Industrial User	20 miles
Wellhead Gas Price	$1.50/mcf
Distance to Pipeline:	5 miles

1. Methane Emitted and Recovered

This section describes the process for estimating the quantity of methane emitted from the mines and the amount of gas that could potentially be recovered and utilized.

Methane Emissions

The first step in performing an evaluation for each mine is to estimate the quantity of methane currently being emitted to the atmosphere. Total emissions are comprised of emissions from ventilation systems and emissions from degasification systems.

All underground coal mines have ventilation systems that pump large quantities of air through the mine to ensure that methane levels remain within safe tolerances. These ventilation systems emit large volumes of methane in low concentrations (typically less than 1.5%). Currently, there are no commercially viable techniques for utilizing methane emitted from ventilation systems.

Methane is also emitted from degasification systems. Approximately 30 underground mines in the U.S. use degasification systems as a supplement to their ventilation systems. These systems, which are described in detail in the background section of the Mine Profiles report (EPA, 1994), are either wells drilled from the surface or boreholes drilled from inside the mine. Degasification systems recover large quantities of highly concentrated methane.

The portion of total methane emissions that are released from degasification systems may vary from as low as 10 percent (for mines that only employ in-mine boreholes) to over 80 percent (for mines that employ a combination of pre-mining and post-mining recovery techniques). For the Sample Mines, recovery efficiencies of 30, 50, and 40 percent were assumed for Sample Mines A, B, and C, respectively.

While the Sample Mines evaluated in this report are assumed to employ degasification systems, some mines with high emissions only use ventilation systems for methane control. By installing degasification systems, these mines would potentially be able to use the recovered gas as an energy source and would also enhance mine safety, improve productivity, and reduce ventilation costs.

Methane Recovered and Utilized

For mines currently using degasification systems, potential methane recovered and utilized may be less than, equal to, or greater than estimated current degasification emissions. Most of the options examined for each mine assume that the total amount of methane currently emitted from degasification systems at the mine could be utilized. These options include use of the gas to generate power for on-site use and sale to a utility. Other options examined for each mine assume that less than 100% of the methane recovered from degasification systems is utilized. For example, for Mine C, the nearby industry that could purchase the gas does not have a high enough annual demand to be able to use all of the methane recovered from the mine. Furthermore, for all the mines, only a portion of the gas recovered is suitable for pipelien sales without requiring enrichment. Accordingly, these scenarios assume that less than 100 percent of the recovered gas is utilized. It is also possible that the amount of methane recovered for utilization could exceed current methane emitted from degasification systems. For example, if a mine were to drill additional gob wells or boreholes or switch to using vertical wells in advance of mining, the amount of gas produced from degasfication systems could be increased.

Quality of Recovered Gas. The quality of the gas recovered depends upon the degasification system employed and site-specific conditions. Methods that recover methane in advance of mining (e.g., horizontal boreholes and vertical wells) produce nearly pure methane. In contrast, methods that recover methane after mining (e.g., gob wells and cross-measure boreholes) may produce methane mixed with mine air. While several U.S. mines are producing methane from gob wells for sale to pipelines, some mines may not be able to produce pipeline quality gas from gob wells. For the Sample Mines, it is assumed that only a small portion of the total amount of methane recovered from gob wells would be suitable for pipeline sales without enrichment. For power generation, gas quality is less of an issue since the gas would be mixed with air prior to combustion. Similarly, gas quality may not be an issue for local use, if a nearby industry or institution can utilize a medium BTU gas.

2. Gas and Electricity Production, On-Site Energy Needs

This section shows the calculations used to determine the amount of gas that could be produced for pipeline sales or local use and the level of electricity that could be generated. Additionally, this section describes how mine energy needs are estimated.

Gas Produced for Pipeline Sales and Local Use. The amount of gas that could be produced for sale to a pipeline or a local user is the amount of methane recovered minus the amount of gas needed to fuel the compressors. Compressors are estimated to require fuel at a rate of 10 cf per brake horsepower hour. The brake horsepower needed for compression is discussed in more detail in Section 3. As shown in that section, the total brake horsepower needed for a pipeline sales project (horsepower for a satellite compressor and a sales compressor) is 493. Compressor loss is calculated as follows:

493 hp x 10 cf/hp hr x 8760 hrs/yr = 43 MM cf/yr

In general, about 5 to 10 percent of the methane recovered will be used to fuel the compressors. For Sample Mine A, the amount of gas used to fuel the compressors represents 7.2% of the total gas recovered.

Additional fuel is used during the production process when enrichment of the gas is required. An estimated 24 percent of the recovered gas is required to fuel the enrichment equipment. For Mine A, the total amount of gas recovered each year minus the amount used to fuel the compressors is 557 MM cf/yr. Assuming that all of this gas will be enriched prior to sale to a pipeline, 24 percent (about 134 MM cf/yr) is used in the enrichment process, leaving 423 MM cf/yr of gas that can be sold to a pipeline.

Electricity Generation. Potential electricity production is estimated from the gas flow rate and the heat rate (BTUs/kwh) of a gas turbine.[1] Gas turbine heat rates may range from 8000 to 14000 BTUs/kwh. For this analysis, the heat rate of a gas turbine is assumed to be 11,000 BTUs/kwh. For Sample Mine A, potential electricity generation is estimated as follows.

600 MMcf/yr - 28.8 MMcf/yr used to fuel the satellite compressor = 571.2 MMcf/yr used to generate electricity.

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[1] Internal combustion engines could also be used, gas turbines, however, are more suitable since they are less sensitive to fluctuations in gas quality.

571.2 MMcf/yr x 970 BTUs/cf x kwh/11000 BTUs = 50.4 MM kwh/yr

The kW capacity needed for the generator would be 50.4 million kwh/yr x yr/8760 hrs = 5.75 MW.

Mine Electricity Demand (kwh/yr). Electricity generated from recovered methane may be used to meet a mine's on-site electricity needs. Electricity demand at underground coal mines varies widely, with the more gassy mines requiring greater amounts of electricity per ton of coal mined due to higher ventilation demands. Based on conversations with mine operators and U.S. Bureau of Mines officials, it appears that electricity demands at gassy underground mines may range from as low as 10 kwh/ton to over 50 kwh/ton. This analysis assumes that the Sample Mines require a value of 24 kwh/ton for the mine and an additional 6 kwh/ton for the preparation plant. For Sample Mine A, annual electricity needs would be calculated as follows: 2 million tons/yr x (24 + 6) kwh/ton = 60 million kwh/yr.

Mine Electric Capacity Demand (kW). A mine's electricity capacity demand pattern is also examined in order to determine how much electricity may be used on-site. As a simplifying assumption, this analysis divides electricity demand into two components: continuous demand and operating demand. Continuous demand is the amount of electricity required 24 hours a day, 365 days a year, regardless of whether the mine is in operation. Operating demand is the additional demand for electricity when the mine is in full operation. The analysis assumes that the sample mines are in operation for 16 hours per day, 220 days per year (3,520 hrs/yr) and that 50 percent of annual electricity needs (kwh/yr) are accounted for by operating demand. Using these assumptions, Sample Mine A's operating demand (in kW) is: (50% x 60 million kwh/yr)/3520 hrs/yr = 8,523 kW. Continuous demand is (50% x 60 million kwh/yr)/8760 hrs/yr = 3,425 kW. Therefore, total electricity demands when the mine is operating are 11,948 kW.

Energy Demand at Preparation Plant. Some coal mines currently use coal as a primary source of fuel for thermal dryers at their preparation plant facilities. In some cases, it may be possible to used recovered gas in place of coal at in thermal dryers. In this analysis, only Mine C uses a thermal dryer. This analysis assumes that Mine C consumes roughly 1 ton of coal for each 150 tons of coal processed in a thermal dryer.

3. Capital and Operating Costs

This section describes the capital and operating costs that are included in the analysis. Table A-1 shows the specific costs that are used and provides sample calculations using data for Sample Mine A.

Degasification Systems. For those mines that already employ degasification systems, the costs of drilling and installing degasification systems are not an incremental cost associated with a utilization project. Accordingly, drilling costs are not included in the economic assessment for Sample Mines A, B, and C. In the Appalachian basin, costs for drilling gob wells typically range from $28 to $42 per foot for a 7 to 10 inch diameter hole, depending on the rock strata above the coal seam. A typical gassy underground coal mine might require a gob well to be drilled to a depth of from 400 to 1300 feet. The number of wells needed varies from 2 to 6 per longwall panel, with an average longwall panel producing about 1 million tons of coal. This analysis assumes that one gob well is drilled for every 250,000 tons of coal mined.

TABLE A1: SUMMARY OF COST ASSUMPTIONS USED IN THE ANALYSIS							
Cost Item	**Number or Size of Units Needed**	**Cost Per Unit**	**Cost Calculation for Sample Mine A**	**Applicable for All Utilization Options?**			**Notes**
				Pipe Line	**Power**	**Local/ OnSite**	
Degasification Systems							
Annual Well Drilling and Installation Costs	1 well for every 250,000 tons of coal mined	Per well drilling costs are $28 to $42 per foot	The number of wells drilled each year at Sample Mine A is 2,000,000 tons of coal mined per year x 1 well/250,000 tons of coal = 8 wells per year. Drilling costs are not included for Sample Mine A because the Mine already employs degasification systems.	X	X	X	For an economic assessment of a methane utilization project, the cost of installing degasification system should not be included for mines that already employ these systems.
Compression Costs							
Wellhead Exhauster/blower Initial capital cost since blowers can be moved from well to well	1 blower for each well	$20,000/well	Cost of blower not included for Sample Mine A since mine already uses gob wells. If Sample Mine A did not use gob wells, cost would be estimated as follows: $20,000 per well x 8 wells per year = $160,000 initial capital cost.	X	X	X	Cost of wellhead blower/exhausters are not included for mines that already employ gob wells since it is assumed the mine already would use a blower at each well.
Compressor Site Preparation	Applicable for satellite and sales compressor	$70,000 for each compressor required	For pipelines sales options: site preparation for Sample Mine A will be $140,000. For other options, where only a satellite compressor is required, site preparation will be $70,000.	X	X	X	Initial capital cost.
Satellite Compressor Capital Cost	200 HP/MMCFD	$600/hp	Gas flow rate for the Sample Mine A is 1.6 MMCFD; 1.6 MMCFD x 200 HP/MMCFD = 320 HP; 320 HP x $600/HP = $192,000	X	X	X	Satellite compressors will pick up the gas coming from the wellhead exhauster/blower at about 16 to 17 psia and will boost the gas to 150 to 250 psia
Sales Compressor Capital Cost	100 HP/MMCFD	$600/hp	Gas flow rate for the Sample Mine A is 1.6 MMCFD; 1.6 MMCFD x 100 HP/MMCFD = 160 HP; 160 HP x $600/HP = $96,000	X			Sales compressor will pick up the gas coming from the satellite compressor at about 250 psia and boost it to 800 to 1000 psia, the typical pressure for a sales pipeline.
Compressor Operating Cost	$12,000 per compressor per year		For pipeline projects, $24,000 per year. For other projects, $12,000 per year.	X	X	X	Annual operating cost.

TABLE A1: SUMMARY OF COST ASSUMPTIONS USED IN THE ANALYSIS							
Cost Item	**Number or Size of Units Needed**	**Cost Per Unit**	**Cost Calculation for Sample Mine A**	**Applicable for All Utilization Options?**			**Notes**
				Pipe Line	**Power**	**Local/ OnSite**	
Gathering Line Costs							
Annual cost of Installing Gathering Lines Between Individual Wells and Satellite Compressors	Average 1200 ft per well	$10/ft. $4 to $6/ft for HPDE pipe not buried; $8/ft to $12/ft for buried lines	Annual cost for Sample Mine A: 8 wells per year x 1200 ft per well x $10/ft = $96,000/yr As a conservative assumption, it is assumed that gathering lines are not reused.	X	X	X	For some mines, it may be possible to reuse gathering lines. For this analysis, it is assumed that the lines are not reused. Therefore, installation costs for lines between new wells and the satellite compressor are included every year.
Initial Capital Cost of Main Line from Satellite Compressor to Sales Compressor Located At Commercial Pipeline	Estimated distance between a mine and the nearest commercial pipeline is shown in background information for each mine evaluated	$200,000/mile 6 to 8 inch lateral line Range $30,000 to $300,000 per mile, depending on terrain and right-of-way costs	Sample Mine A is located five miles from a commercial pipeline. Cost would be $200,000 mile x 5 miles = $1,000,000.	X			Main lateral line from mine to sales pipeline may be a low pressure line. Sales compressor used to boost the gas from 250 psia to 800 to 1000 psia would be located near the sales pipeline, allowing the mine to run a less expensive, low pressure line from the satellite compressor to the sales compressor.
Initial Capital Cost of Main Line from Satellite Compressor to On-Site Generator or Prep Plant	2000 feet	$10/ft	Sample Mine A: 2000 ft x $10/ft = $20,000		X	X on-site use	Initial capital cost.
Initial Capital Cost of Main Line from Satellite Compressor to Local End User	Estimated distance between a mine and the nearest commercial pipeline is shown in background information for each mine evaluated	$200,000/mile	Sample Mine A is estimated to be 25 miles from a local industry that can use the recovered gas. Costs are 20 miles x $200,000/mile = $6,000,000.			X off-site sale	Initial capital cost.

TABLE A1: SUMMARY OF COST ASSUMPTIONS USED IN THE ANALYSIS							
Cost Item	**Number or Size of Units Needed**	**Cost Per Unit**	**Cost Calculation for Sample Mine A**	**Applicable for All Utilization Options?**			**Notes**
				Pipe Line	**Power**	**Local/ OnSite**	
Dehydration							
Wellhead Drip-pot separator	1 separator for each well	$2,000	Sample Mine A has 8 wells x $2,000 per well - $16,000	X	X	X	Considered an initial capital cost since separators can be moved
Dehydrator, Processing Equip.	$40,000 per project		Sample Mine A will require a dehydration system at $40,000	X		X	Initial capital cost.
Operating Cost for Dehydrator	$3,000 per unit per year		Annual dehydration operating costs for Sample Mine A are $3,000.	X		X	Annual operating cost.
Other Standard Equipment							
Gas Flow Meters; Other Equipment	Gas flow meters are $5,000/well; other equipment is $100,000 per project		Initial Capital Costs for Sample Mine A are $140,000	X	X	X	Initial capital cost.
Equipment Costs for Pipeline Sales Projects							
Gas Sales Meter and Gas Analyzer	Combined costs for gas sales meter and gas analyzer are $20,000		Initial Capital Costs for Sample Mine A are $20,000	X			Initial capital cost.
Enrichment Equipment	$2,100,000 per project		Initial capital costs for an enrichment project are $2.1 million.	X			Initial capital cost.
Enrichment Operating Cost	$0.10/mcf		$0.10/mcf x 600,000 mcf/yr = $60,000/yr	X			Annual operating cost.
Equipment Costs for Power Generation Projects							
Gas Turbine	Size of turbine (kW) = Gas Flow Rate cf/hr x 970 BTUs/cf x 1 kwh/11000 BTUs	$1,100 per kW installed capacity	Mine A's gas flow rate is 0.6 Bcf/yr (65,200 cf/hr after compression loss). 65,200 cf/hr x 970 BTU/cf x kwh/11000 BTUs = 5,750 kW capacity needed. 5,750 kW x $1100/kW = $6.32 million		X		Initial Capital Cost
Turbine Operating Costs	$0.01/kwh generating capacity		Sample mine 11,900 kW x 8760 hours/yr = 50.4 million kwh/yr. 50.4 million kwh/yr x $0.01/kwh = $503,695/yr		X		Annual Operating Cost
Utility Interconnection Cost	$300,0000 initial project cost. Range: $100,00 to $500,000		Sample Mine Cost: $300,000 per project		X		If a mine only used electricity to meet on-site needs, this cost would not be included.

TABLE A1: SUMMARY OF COST ASSUMPTIONS USED IN THE ANALYSIS							
Cost Item	Number or Size of Units Needed	Cost Per Unit	Cost Calculation for Sample Mine A	Applicable for All Utilization Options?			Notes
				Pipe Line	Power	Local/ OnSite	
Equipment Costs for On-Site Use of Gas or Sale to Local User							
Conversion Cost for Using Gas in On-site Prep Plant	$750,000 initial project cost. Range: $500,000 to $1,000,000		Initial capital costs for Mine A would be $750,000 per project.			X	Initial capital cost
Conversion Cost for Industrial/ Institutional User Purchasing Coal Mine Gas	$800,000 Range: $400,000 to $1,200,000		Initial capital costs for Mine A would be $800,000 per project			X	Initial capital cost
Other Annual Operations Costs							
General Operations and Maintenance	$30,000/yr		For Sample Mine A, additional annual operations expenses are $30,000 per year.	X	X	X	Includes parts, supplies, fuel, etc.
Employee Wages and Benefits	Minimum of either $100,000 or $10,000 x Number of wells drilled each year		For Sample Mine A, labor costs are $10,000/well x 8 wells per year = $80,000. Since $80,000 < $100,000, an estimate of $100,000/yr is used.	X	X	X	Annual operating cost
Insurance	$30,000/yr		For Sample Mine A, insurance costs are $30,000 per year.	X	X	X	Annual operating cost

Compression

The analysis assumes that all utilization options will require compression of the gas in order to move it from the wellhead to the point of sales or end-use. The number and size of compressors needed depends upon the gas flow rate, the distance to the point of use or sale, and the pressure to which the gas must be compressed. All systems will include wellhead blower/exhausters and a satellite compressor. Sale to a high pressure pipeline may require an additional sales compressor. Exhibit A-1 shows the location of wellhead, satellite, and sales compressors at Mine A.

Gob wells that vent methane to the atmosphere are normally equipped with a blower/exhauster to enhance gas production for mine safety reasons. These units typically apply a suction pressure of 2.5 to 5 psi (negative gauge) to the wellbore and discharge a few psi above atmospheric pressure (16 to 17 psi). These blower/exhausters would provide sufficient pressure to move the gas along the gathering lines to a satellite compressor. Costs for wellhead blower/exhausters, which range from $10,000 to $30,000 depending on size and prime mover, are not included for mines that already are assumed to have degasification systems in place.

For all utilization options, a satellite compressor would be used boost the gas from 16 to 17 psi to 150 to 250 psi, a pressure sufficient for on-site use in a turbine or preparation plant. As shown in Table A-1, the estimated brake horsepower needed for the satellite compressor is 200 HP per million cubic feet of gas per day. The total estimated cost of a satellite compressor includes a flat cost for site preparation ($70,000 per unit) plus a cost of $600 per brake horsepower.

For options involving sale of the gas to a high pressure pipeline, an additional sales compressor would be needed to boost the gas from 250 psi to 800 to 1000 psi, the typical pressure for a sales pipeline. The size of compressor needed is calculated by assuming that 100 HP are needed per million cubic feet of gas produced per day. Normally, the sales compressor would be located near the sales pipeline so that low pressure gathering lines could be used to transport the gas to the pipeline.

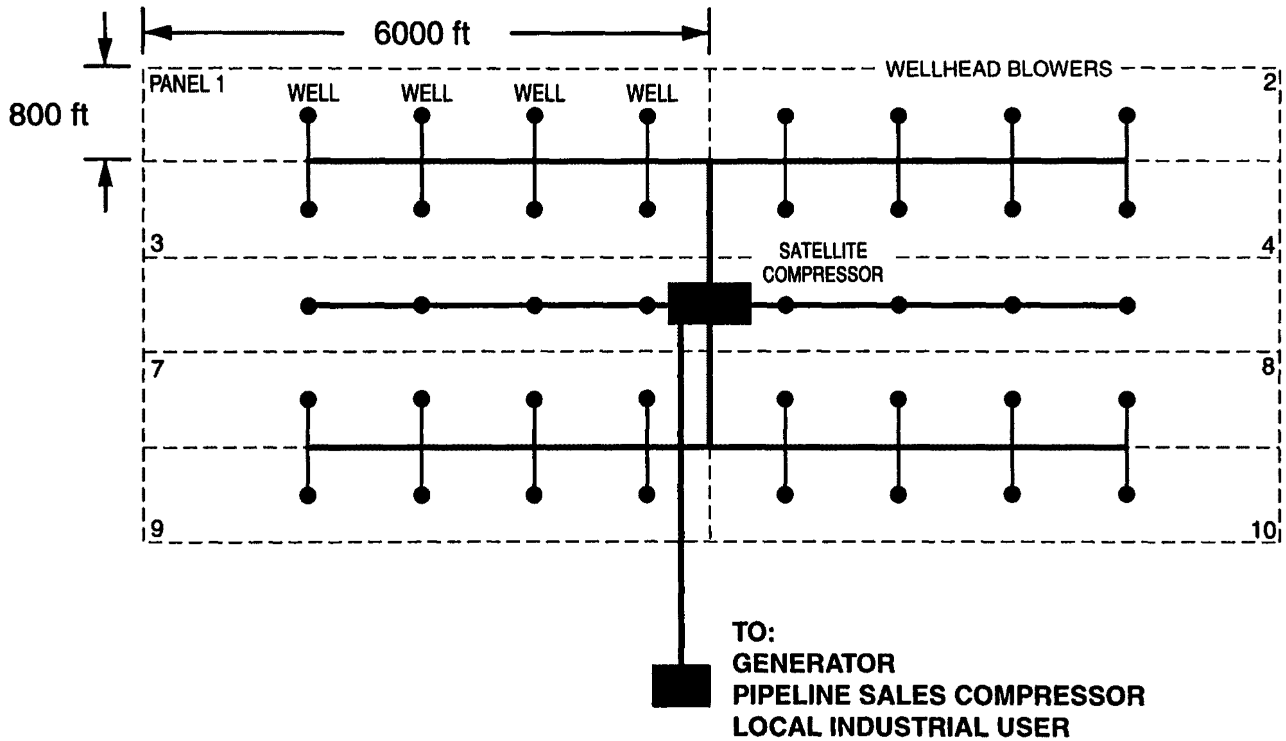
Annual operating costs for compressors are assumed to be $12,000 for each compressor.

Gathering Line Costs

For each mine, gathering lines will need to be installed between individual wells and the satellite compressor. Additionally, a main gathering line will need to be installed that leads from the satellite compressor to either: an on-site generator or preparation plant, a sales compressor located at a commercial pipeline, or a local gas consumer. A diagram of the layout for Mine A is shown in Exhibit A-1. As shown in this Exhibit, the length of gathering line needed between individual wells and the satellite compressor is estimated to be 1200 feet, while the length of line between the satellite compressor and an on-site preparation plant or gas turbine is assumed to be 2000 feet. The estimated distance between the satellite compressor and a sales compressor or local gas consumer is determined on a mine-by-mine basis and is reported in the Mine Characteristics table of each assessment.

Exhibit A-1

Schematic of Gob Well Gas Gathering System



This analysis assumes that High Density Polyethylene (HPDE) pipe is used for the gathering lines. Given the range of gas flows that would be common for a coal mine methane recovery project, the diameter of the pipe is assumed to be from 4 to 6 inches. On mine property, the lines may potentially be left above ground. In other areas, the lines will likely need to be buried. Costs for a 4-inch HPDE line installed on the surface range from $4.00 to $6.00 per foot, depending on terrain. If burial of the lines is required, costs would likely range from $8 to $12 per foot. As a conservative assumption, this analysis assumes a cost of $10 per foot for gathering lines. In many cases, it may be possible to reuse gathering lines leading from wells to the satellite compressor (lines may be moved as one well stops producing and another well comes on line). As a conservative assumption, this analysis assumes that gathering lines could not be reused.

Dehydration/Processing. All utilization options will require gas/water separation at the wellhead, which is accomplished by using a small drip-pot, two-phase water separator placed at each gob well. Capital costs for each unit are about $2,000 dollars and operating costs are negligible. Utilization options involving gas sales to a pipeline or local user or use of the gas in an on-site preparation plant will require additional dehydration. Glycol dehydrators may be used to remove remaining water vapor in the gas. For sale to a pipeline, the dehydration unit is normally used after compression to sales specifications. A large scale (2 MMcfd), high pressure (1000 psi) glycol separator unit can be obtained for between $20,000 and $50,000. This analysis assumes a capital cost of $40,000. Operating costs for glycol dehydrators are assumed to be $3,000 per year.

Additional Gathering System Equipment. Additional gathering system equipment include wellhead gas flow meters and other safety and processing equipment, which are estimated to cost $5,000 per well and $100,000 per project, respectively.

Enrichment Equipment for Pipeline Sales. While some U.S. mines have been able to sell methane recovered from gob wells to pipeline companies, enrichment of the gas to pipeline standards may be required. For each of the Sample Mines, it is assumed that enrichment will be required for a large portion of the methane recovered from gob wells. Enrichment consists of removing nitrogen, oxygen, and carbon dioxide from the gob gas. Initial studies (e.g., DOE 1993) indicate that it should be technically and economically feasible to enrich gob gas using a facility consisting of 1) a pressure swing adsorption (PSA) or selective absorption nitrogen rejection unit, 2) a catalytic combustion deoxygenation process, 3) an amine or membrane carbon dioxide removal system (if required), and 4) a conventional dehydration unit. Total capital costs for a system relying on PSA for nitrogen removal are about $2.1 million (excluding dehydration costs, which are discussed above). Operating costs are estimated to be $0.10/mcf. These capital and operating costs are assumed in the analysis.

Additional Equipment for Pipeline Sales. In addition to the gathering system equipment described above, an additional gas flow meter and gas analyzer are needed for sale to a pipeline. The cost of this equipment is estimated to be $20,000.

Capital and Operating Costs for Power Generation Projects. The primary capital cost for projects involving the use of recovered methane to generate electricity is the cost of a gas turbine. Capital costs for gas turbines range from $800 to $1200 per kW installed capacity. For this analysis, a capital cost of $1100 per kW is used. Operating costs are about $0.01/kwh. In cases in which the mine could sell electricity generated in excess of on-site needs to a utility, the analysis includes an additional "interconnection cost" of $300,000. The interconnection cost includes all capital costs associated with upgrading electric lines and installation of other equipment needed so that the mine can sell electricity to the local grid. Interconnection costs are likely to be in the range of $100,000 to $500,000 for typical small power production projects (less than 80 MW).

An additional cost that may be incurred by mine operators desiring to generate electricity to meet on-site electricity needs is the cost of "backup power." Utilities may charge high rates for the "backup power" needed at the mine during times when the on-site generator is not functioning. While the Public Utility Regulatory Policies Act (PURPA) stipulates that utilities must supply backup power at nondiscriminatory rates, these charges may be much higher than the normal rates paid by the mine due to the utility's need to maintain sufficient capacity levels to meet the electricity demands of the mine. The additional costs of backup power are not included in this assessment.

Conversion Cost for On-Site Use of Gas in a Preparation Plant or Sale of Gas to Nearby User. For on-site and local direct gas use options, in addition to the costs required for gathering, compression, and dehydration, the analysis includes a cost for conversion of existing equipment to run on recovered coal mine methane. For the Sample Mines, the cost for converting an on-site thermal dryer to operate on coal mine methane is estimated to be $750,000. This estimate includes all converstion costs associated with switching from using coal to using gas in a thermal dryer. For sale to a nearby industrial or institutional user, a conversion cost of $800,000 is assumed. These conversion costs are assumed to include all capital costs, fees, and permits associated with converting a system to operate on medium to high BTU coal mine methane gas.

General Operations, Maintenance, and Insurance

In addition to the compression, dehydration, enrichment, and power generation operating costs listed above, annual operating expenses are included for the following three items: 1) employee salaries and benefits 2) general equipment maintenance, and 3) insurance.

For employee salaries and benefits, the analysis assumes that a project would require at least two full-time personnel to maintain and operate a gas recovery system. Salaries and benefits for each person are estimated at $50,000 per year, for a total of $100,000. Since larger projects may require additional personnel, this analysis assumes that employee salaries and benefits are a minimum of either $100,000 or $10,000 per number of wells drilled each year.

In addition to the operating costs discussed above for compression, dehydration, enrichment, and power generation, a flat annual cost of $30,000 is also included for equipment maintenance and materials.

Finally, insurance costs associated with a methane utilization project are estimated to be $30,000 per year.

4 Revenue and Savings

This section describes how annual revenues and savings are calculated in the economic assessment.

Revenues from Pipeline Sales. Sale of recovered coal mine methane gas may yield high revenues, depending upon the amount of gas recovered and the wellhead gas price. For the Sample Mines, it is assumed that the wellhead gas price is $1.50 per mcf. For Sample Mine A, assuming that the mine recovers methane from gob wells and that enrichment is required, total gas produced for sale is 423,000 mcf/yr (see discussion above regarding amount of gas produced for pipeline sales). At a wellhead gas price of $1.50/mcf, total annual revenues for Mine A are $634,500.

Savings from On-site Use of Electricity and Revenue from Electricity Sales. In the analysis, mines are assumed to first use all electricity generated to meet on-site electricity needs and then to sell any excess electricity to a utility. This analysis shows that many of the gassiest mines could generate more electricity than is needed on-site. The annual savings that may be achieved from on-site use of electricity is determined by multiplying the electricity used to meet on-site needs (kwhs/yr) by the assumed price the mine currently pays for its electricity (which varies by mine and is shown in the Mine Characteristics table).

For Mine A, the electricity used to meet on-site needs is calculated as follows. As shown in Section 2 of this Appendix, the level of electric capacity that could be generated at the Sample Mine is roughly 5.75 MW, which is higher than the mine's continuous demands of 3.4 MW, but lower than the mine's total operating demands of 11.9 MW. The price the mine pays for its electricity is $0.055/kwh. The savings associated with generating electricity to meet continuous demands would be 3.4 MW x 8760 hrs/yr x $0.055/kwh, or approximately $1.6 million per year. During times when the mine is in full operation (16 hours/day, 220 days a year, or 3520 hours/yr), the full 5.75 MW of capacity may be used to meet on-site needs. The electricity savings associated with meeting this additional operating demand are:

5.75 MW total demand - 3.4 MW continuous demand = 2.35 MW
2.35 MW x 3,520 hours/year x $0.055/kwh = $0.5 million per year.

Accordingly, for Mine A, the total savings that can be achieved from using recovered methane to meet on-site needs are $2.1 million ($1.6 million to meet continuous needs plus $0.5 million to meet additional operating needs).

The annual revenue that may be realized from selling "excess" electricity to a utility is estimated by multiplying the electricity generated in excess of on-site needs by the assumed avoided cost of the local electric utility (the utility avoided cost assumed for each mine is shown in the Mine Characteristics table). For Sample Mine A, the utility avoided cost is $0.045/kwh. Furthermore, electricity will be generated in excess of on-site needs only during times when the mine is not fully operating. Since the mine is assumed to be in full operation 3520 hours per year, it is not fully operating the remaining 5,240 hours per year. Since 3.4 MW are required for continuous demand, an additional 2.35 MW of capacity are available during times when the mine is not fully operating. Revenues are calculated as: 2.35 MW x 5,240 hours/yr x $0.045/kwh, or nearly $0.6 million per year.

Revenue from Sale of Gas to a Nearby Industrial or Institutional User. Sale of recovered gas to a nearby industrial or institutional user may generate high revenues due to the high commercial and industrial gas prices charged in many coal mining areas (typically in the range of $4/mcf to $6/mcf). The analysis assumes that Mine C could sell recovered methane at a price that 75 percent lower than the local industrial gas price, which was assumed to be $5/mcf.

Savings from On-Site Use of Gas in a Thermal Dryer. Some mines currently use coal to fuel thermal dryers at their preparation plant facilities. In some cases, the coal used in thermal dryers is lower quality coal that would not be suitable for sale. In other cases, higher quality coal that could be sold is used as fuel. Assuming higher quality coal is used in the preparation plant, the mine operator could achieve savings by using methane in place of coal. The annual savings that may be achieved are calculated by multiplying the market rate for bituminous coal by the amount of coal that would be "saved" by using gas in the preparation plant. Of the Sample Mines, only Mine C uses coal to fuel a thermal dryer at its preparation plant.

5 Financial Assumptions

In order to perform a net present value analysis of a methane utilization project, the following financial assumptions are used.

Project Lifetime: For the Sample Mines, unless otherwise noted, the assumed remaining lifetime of the mine is used as the lifetime of the project.

Inflation Rate: The annual rate of inflation is assumed to be 4 percent.

Discount Rate: A real discount rate of 6 percent is assumed, which is roughly equal to a nominal discount rate of 10 percent (6 percent real discount rate + 4 percent inflation rate).

Financing of Capital Investments: As a conservative and simplifying assumption, all equity financing is assumed for capital investments.

Depreciation Method: Straight-line depreciation is used for all capital items. The depreciation period is assumed to be the same as the project lifetime. No salvage value is included in the assessment.

Depletion: No depletion allowance is included.

Tax Rate: A marginal combined state and federal tax rate of 40 percent is assumed.

Nonconventional Fuel Tax Credit: Coalbed methane produced from wells drilled between December 31, 1979, and January 1, 1993, may qualify for the nonconventional fuel tax credit established under Section 29 of the Internal Revenue Code. Since it is assumed that gob wells would be drilled after January 1993, this tax credit is not included in this analysis.

Royalties: Royalty payments of 12.5 percent are included in the analysis.

Appendix B.

1990 Coal Production and Methane Emissions for Mines Known or Believed to Have Degasification Systems

Mine Name	Reported Coal Production (mmtons/yr)	Reported Vent Emissions (Bcf/yr)	Estimated Degas Emissions[1] (Bcf/yr)	Estimated Total Emissions (Bcf/yr)	Estimated Emissions Per Ton (cf/ton)
Amonate[2]	1.0	0.8	0.4	1.2	1222
Arkwright No.1	1.9	1.4	0.8	2.2	1153
Bailey[3]	5.6	1.8	0.9	2.7	483
Blacksville No. 2	3.8	3.4	1.8	5.2	1369
Cumberland	3.0	2.1	1.1	3.2	1080
Deserado	1.7	0.5	0.3	0.8	487
Emerald No. 1	1.6	1.1	0.6	1.8	1062
Federal No. 2	4.2	3.8	2.1	5.9	1405
Golden Eagle	1.5	2.2	1.2	3.4	2216
Humphrey	3.3	2.3	1.2	3.5	1069
Loveridge No. 22[2]	2.8	1.9	1.0	2.8	1033
Mine 84[4]	1.3	1.1	0.0	1.1	853
Old Ben No. 26	2.6	0.7	0.4	1.0	395
Osage No. 3	1.8	1.4	0.7	2.1	1171
Pinnacle No. 50[5]	3.4	2.8	2.8	5.6	1669
Robinson Run No. 95	1.9	0.8	0.4	1.2	635
Shawnee[5]	1.1	0.5	0.3	0.7	672
Wheatcroft No. 9	2.7	0.2	0.1	0.3	127

[1] Degasification emissions were estimated to be 35% of total emissions for all mines except Pinnacle No. 50. For this mine, it was reported that degasification emissions represent 50% of total emissions.
[2] These mines are currently idle.
[3] This mine is part of the Bailey/Enlow Fork mine complex. Enlow Fork began producing coal in the early 1990s.
[4] It is unclear whether this mine had a degasification system in 1990, or has one at present.
[5] Pinnacle No. 50 and Shawnee have recently merged to form one mine, Pinnacle No. 50.

Detailed information on these mines is provided in the EPA report *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Draft Profiles of Selected Gassy Underground Coal Mines.*

FOR MORE INFORMATION...

For more information on coalbed methane recovery experiences, project potential, or program activities and accomplishments, contact:

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Selected list of EPA Coalbed Methane Outreach Reports:

- USEPA (U.S. Environmental Protection Agency). **Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Draft Profiles of Selected Gassy Underground Coal Mines.** Office of Air and Radiation (6202J). Washington, D.C. EPA-430-R-94-012. September 1994.

- USEPA (U.S. Environmental Protection Agency). **The Environmental and Economic Benefits of Coalbed Methane Development in the Appalachian Region.** Office of Air and Radiation (6202J). Washington, D.C. EPA-430-R-94-007. April 1994.

- USEPA (U.S. Environmental Protection Agency). **Opportunities to Reduce Anthropogenic Methane Emissions in the United States. Report to Congress.** Office of Air and Radiation (6202J). Washington, D.C. EPA-430-R-93-012. October 1993.

- USEPA (U.S. Environmental Protection Agency). **Anthropogenic Methane Emissions in the United States: Estimates for 1990. Report to Congress.** Office of Air and Radiation (6202J). Washington, D.C. EPA-430-R-93-003. April 1993.

In addition, EPA reports exploring the various state and federal financing assistance available for coalbed methane projects will be available soon.