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Project Summary

National Assessment of Environmental and Economic Benefits from Methane Control and Utilization Technologies at U.S. Underground Coal Mines

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Methane is a greenhouse gas in the atmosphere which ranks behind carbon dioxide as the second largest contributor to anthropogenic-induced global warming. Methane emissions from coal mines are one of the primary sources responsible for the buildup of methane in the troposphere, prompting the U.S. Environmental Protection Agency's Air Pollution Prevention and Control Division to conduct research into the emission processes and control strategies associated with underground mines in the U.S. The goals of this research program have been to assess the economic performance and emissions reductions of methane control strategies for underground mines, and to develop modeling tools and data bases which miners can use to conduct their own site-specific methane control analyses. To this end, nine standard or model mines were designed to closely simulate existing mines in the major coal producing regions. Cost performance and methane reductions were then calculated for a number of methane recovery and utilization combinations at these model mines. Algorithms were developed using site-specific mine designs, geological parameters, and costs, with the assistance of mine operators, mining consultants, degasification system consultants, and the U.S. Bureau of Mines.

This Project Summary was developed by the National Risk Management Research Laboratory's Air Pollution Prevention and Control Division, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in a separate report of the same title (see Project Report ordering information at back).

Introduction

Methane is a greenhouse gas in the atmosphere which ranks behind carbon dioxide as the second largest contributor to anthropogenic-induced global warming. Methane emissions from underground coal mines are one of the primary sources responsible for the buildup of methane in the troposphere, prompting the U.S. Environmental Protection Agency's Air Pollution Prevention and Control Division to conduct research into the emission processes and control strategies associated with underground mines in the U.S. The goals of this research program have been to assess the economic and emissions performance of methane control strategies for underground mines, and to develop modeling tools and data bases which miners can use to conduct their own site-specific methane control analyses. This study has not focused on evaluating "command and control" regulatory strategies for the mining industry; rather, the emphasis has been on highlighting technology applications which would simultaneously increase mine profits and reduce methane emissions (i.e., identify the "win-win" methane control applications).

Reduction of methane emissions from underground coal mines requires that practical and cost effective techniques be available that can capture and use the methane contained in coal. Fortunately, a suite of coalbed methane degasification (degas) and utilization techniques are available, and many of these techniques are capable of reducing methane emissions while simultaneously creating new sources of revenue and energy for a mine. The U.S. Bureau of Mines has conducted numerous feasibility studies which provide guidelines on successfully implementing degas technologies. However, many mines still do not use these systems, and those that do, do not utilize the recovered gas — they simply vent it to the atmosphere. Causes of the lack of utilization include: costly investments required for equipment and personnel, poor understanding of costs and revenue potential, conflicts in gas ownership rights (especially in the Northern Appalachian Basin), and a higher priority for coal mining rather than utilizing coal mine gas.

The report gives results of a national engineering and economic assessment of coal mine degas and gas utilization systems. The evaluation was conducted by examining the application of degas/utilization systems applied to a group of representative mines operating in all major U.S. coal basins. The emissions and economic performances of various technologies were developed using site-specific mine design and geological parameters, and cost analyses models developed and quality assured with the assistance of mine operators, mining consultants, degas system consultants, degas system research organizations, and the U.S. Bureau of Mines.

Study Overview

Prior to executing the analysis, a substantial effort was launched to gather and analyze the engineering, economic, and geological data needed to define key study parameters. Using the data collected, groups of parameters were defined including: (1) the population of mines in each major basin, (2) the design and cost of coal mining in each basin, (3) the level of methane control and utilization mines currently employ, (4) the performance and availability of established and developmental methane control and utilization strategies, and (5) the design and cost parameters for these methane control and utilization strategies. The engineering and cost data collected were used to develop a detailed engineering and economic analysis model. This model automated the laborious tasks of calculating underground mine design parameters and costs for different mining regions, determining degas/utilization system design factors and costs, and integrating the feedback effects which degas systems have on normal mine operations.

Nine underground mines, referred to as "standard mines," were defined to represent the population of underground mines operating in the five major coal producing regions of the U.S. The regions examined were the Black Warrior Basin (Standard Mines 1 and 2), the Central Appalachian Basin (Mines 3 and 4), the Northern Appalachian Basin (Mines 5, 6, and 7), the Illinois Basin (Mine 8), and the Western region (Mine 9). These standard mines are similar to actual mines: (1) they share the same coal production rates, methane emission levels, and degas systems, (2) they are located in the same geographic region, and (3) they are identified with the same coal seam stratigraphy. Table 1 summarizes key parameters used to define these nine mines.

The suite of mines examined were structured to exclude very small and low meth-

Table 1. Description of Standard Mines

Standard Mine No.	1	2	3	4	5	6	7	8	9
Region	Warrior	Warrior	Central Appal.	Central Appal.	North. Appal.	North. Appal.	North. Appal.	Illinois	Western
State	AL	AL	WV	VA	PA	PA	WV	IL	CO
County	Jefferson	Tuscaloosa	Raleigh	Buchanan	Indiana	Greene	Monongalia	Franklin	Las Animas
Seam Mined	Mary Lee	Mary Lee	Beckley	Pocahontas No 3	Freeport	Pittsburgh	Pittsburgh	Herrin No 6	Maxwell
Mining Method	LW	LW	R&P	LW	R&P	LW	LW	LW	LW
Coal Production (MMtpy)	1.2	2.4	1.0	1.8	1.0	3.0	3.0	3.0	1.5
CH_4 Emissions (MMcfy)									
From Vent. Systems	548	6,351	694	2,628	402	2,117	1,351	767	1,862
From Degas Systems	0	2,446	0	2,555	0	803	811	365	913
Total	548	8,797	694	5,183	402	2,920	2,162	1,132	2,775
Base Case System									
Degasification	None	GW&HB	None	GW&HB	None	GW	GW&HB	GW	GW&HB
Utilization	None	None	None	None	None	None	None	None	None
Power Req. (MMkW-hr/yr)									
Continuous Demand	22.53	63.39	32.51	38.67	30.52	44.78	45.23	42.12	36.18
Operating Demand	31.62	51.90	18.55	35.30	18.55	27.27	28.61	28.61	26.12
Electricity Purchase Price ($/kW-hr)	0.040	0.040	0.045	0.045	0.063	0.063	0.045	0.044	0.035
Excess Power Buy-Back Rate ($/kW-hr)	0.020	0.020	0.023	0.023	0.032	0.032	0.023	0.022	0.017
Pipeline Distance (miles)	3	10	3	5	1	1	1	3.3	23
Wellhead Gas Sales Price ($/1000 ft^3)	2.90	2.90	2.00	1.82	1.91	1.91	2.00	2.11	147

MMtpy = million tons of coal produced per year
MMcfy = million cubic feet methane emitted per year
MMkW-hr/yr = million kilowatt hour per year
GW = gob wells
HB = horizontal boreholes
LW = longwall
R&P = room and pillar

ane emitting mines because they neither contribute significantly to national emissions, nor are they good candidates for the cost effective installation of degas systems. For each of the nine standard mines examined, mine design and local stratigraphy were defined based on data compiled for actual sites operating in each region. While several standard mines were defined to currently use mine ventilation as a primary source of methane control, others were defined to use some form of advanced methane control and utilization. This is referred to as the base case methane control level, and is important here because the base case technology forms the benchmark against which the performance and cost of more advanced technologies are measured.

A suite of available and developmental degas technologies are examined here. These technologies include: gob wells, cross-measure boreholes, horizontal boreholes, conventional vertical wells, and nitrogen gas injection wells (developmental). Gob wells are drilled from the surface to drain methane from portions of overlying strata allowed to collapse after the coal is removed. Cross-measure boreholes also degas these areas but are drilled from inside the mine. Horizontal boreholes, conventional vertical wells, and gas injection wells are often referred to as “advance of mining” degas systems. These systems recover gas from coal which is slated for mining months or years in future. Horizontal boreholes are drilled from inside the mine, while conventional vertical wells and gas injection wells are drilled from the surface. Surface drilled wells remove gas from the primary mined seam, but can also be installed to remove methane from gas bearing strata above and below the primary seam. These, referred to as multi-zone wells, provide the additional mining benefit of removing the sometimes substantial quantities of gas that can enter mine workings from strata above and below the mined seam. The gas injection process is a relatively new technology which has never been demonstrated at an actual mine site. It is included here because several pilot tests in the western U.S. show that it has the capability to remove a large volume of gas at a much faster rate than the conventional wells described above.

Once gas is recovered from the coal and brought to the surface, it can be utilized in a number of ways. Two methane utilization strategies are examined here: on-site power generation with gas turbines, and sales to a national transmission pipeline. These end-use technologies are selected primarily because they have been successfully used at coal mines, and show the greatest promise of being used at other sites. With the pipeline option, gas purification systems are sometimes needed to purify low to medium Btu gas to pipeline quality. The cost of the purification systems is included with other equipment and operating costs needed to execute the pipeline option.

The engineering and economic data used here were developed using industry standard practices. The development of mine design, degas design and performance, and economic analysis procedures were developed by Southern Research with the direct assistance of coal mining and degas system experts including the John T. Boyd Company, the AMOCO Production Company, Resource Enterprise Incorporated (REI), the Bureau of Mines, and Energy Ingenuity Company. Using data and guidance from these and other groups, a discounted cash flow analysis was executed to determine the annual profit, net present value, and internal rate of return (IRR) for each standard mine and base case control strategy. This analysis was then repeated for the standard mines, but with the addition of the suite of different methane control and utilization technologies described above. The economic and emission reduction performance of each degas technology is judged based on its performance relative to the base case technology. The results of these comparisons are summarized below.

Summary of Findings

Table 2 lists the most economically promising degas and utilization technology options identified for the nine standard mines examined. The table identifies the mining region, the mine size, the base case methane control used, the estimated reduction in methane emissions, and the most promising alternative degas technologies. Three economic parameters are presented: incremental net present value (NPV), incremental annual profit, and incremental internal rate of return (IRR). The use of incremental values simplifies the direct comparison of the base case and the alternative degas technologies, and are calculated by subtracting the NPV, annual profit, or IRR of the base case technology, from the values associated with the alternative degas technology.

The summary below identifies a degas technology as providing better economic performance when: (1) NPV and annual profit for the advanced degas technology option exceed the values occurring with the base case methane control technology, and (2) the IRR is higher than 10%, the discount rate of return. In many cases, several degas options appear to provide better economic performance. The following summary of the trends observed and findings reached is based on the data in Table 2.

Mine-Specific Trends and Findings

- Using one of the technologies examined in the study, all longwall mines could potentially change their current methane control practices to increase profits and decrease emissions. In general, one or more “win-win” methane control options were identified. The room and pillar mines perform poorly, primarily due to the low volume of gas encountered.
- Mines 2, 4, 6, 7, and 9 represent the highest emitting U.S. operations. Each mine currently uses gob wells or gob wells with horizontal boreholes to reduce in-mine methane emissions, and each has several available options which provide better economic performance to this technology. Utilizing gas from already existing degas systems reduces methane emissions. Additional emissions reductions can also occur in these areas if multi-zone conventional vertical wells are utilized. However, these systems require large capital outlay.
- The most profitable option for the mines identified with methane control technology already in place (except for Mine 8 in the Illinois Basin) is utilization of the gas recovered from the base case systems. The existing degas system combined with gas turbine or pipeline sales offer high IRRs and annual profit ranging between \$1 million and \$6 million.
- The more gassy mines, Mines 2, 4, and 6, have a large number of degas options that provide better economic performance compared to the base case.
- The least gassy room and pillar mines (Mines 3 and 5) are not identified with economical degas options due to the low volume of gas present in this area. An estimated 1 to 6% increase in coal production rate can offset the cost of implementing the degas system at these sites.

Region Specific Trends

- In general, this national assessment suggests that investments in degas and utilization systems yield higher returns in the Warrior and Central Appalachian regions than in any other

Table 2. Summary of Results for the Most Promising Degas Technology Options

					Incremental Economic Performance[b]					
					Gas Turbine Option			Pipeline Sales Option		
Mine No.	Mining Region	Coal Prod. MMtpy	Degas Technology	Estimated Methane Reduced[a] %	NPV (MM $)	Annual Profit (MM $)	IRR %	NPV (MM $)	Annual Profit (MM $)	IRR %
1 (base)	Warrior	1.2	None	0	0	0	0	0	0	0
			HB	25				0.24	0.24	11.1
			CVW[c]	99				8.88	1.67	25.3
2 (base)	Warrior	2.4	GW/HB	0	0	0	0	0	0	0
			GW/HB	28	30.31	4.58	38.10	39.46	5.26	75.6
			CVW[c]	32	32.86	5.53	31.2	43.81	6.46	49.3
			GW/HB/CVW[d]	45	13.35	3.65	16.7	37.82	5.74	40.8
			GW/HB/CVW[c]	71	14.78	4.46	15.6	55.09	8.18	45.3
			GI[c]	42	9.09	4.01	13.3	9.09	3.99	13.3
			GW/HB/GI[c]	81				25.01	6.10	18.1
			GW/HB/GI[d]	48				7.48	3.60	12.1
3 (base)	Central Appal.	1.0	None	0	0	0	0	0	0	0
			None							
4 (base)	Central Appal.	1.8	GW/HB	0	0	0	0	0	0	0
			GW/HB	49	23.52	3.72	32.9	25.22	3.39	72.2
			CVW[c]	58	25.51	4.47	28.3	29.09	4.34	47.6
			GW/HB/CVW[d]	67	12.81	3.34	17.1	20.28	3.31	33.2
			GW/HB/CVW[d]	99	14.81	4.55	15.4	33.25	5.14	39.2
			GI[c]	71	1.20	3.07	10.4			
5 (base)	North Appal.	1.0	None	0	0	0	0	0	0	0
			None							
6 (base)	North Appal.	3.0	GW	0	0	0	0	0	0	0
			GW	37	7.59	1.17	35.4			
			HB	38	10.34	1.69	31.2	0.98	0.29	15.6
			GW/HB	61	12.45	2.50	21.5			
			CVW[c]	83	7.44	2.73	14.3			
			CVW[d]	46	3.45	1.33	14.0			
7 (base)	North Appal.	3.0	GW/HB	0	0	0	0	0	0	0
			GW/HB	36	3.6	0.90	17.4			
			CVW[c]	51	2.77	2.04	11.8			
8 (base)	Illinois	3.0	GW	0	0	0	0	0	0	0
			XM	32	0.03	0.20	10.2			
9 (base)	Western	3.0	GW/HB	0	0	0	0	0	0	0
			GW/HB	33	2.79	0.79	16.0			
			CVW[c]	28	9.76	1.80	26.3			

[a] Emissions reduction for non-base case degas systems should be considered approximate (1) because the true effects of methane recovery on in-mine methane liberation potential cannot be assessed, and (2) the volume of gas being vented is derived from straight accounting of the recoverable gas in place.
[b] Incremental Performance = option degas technology - base case technology.
[c] Degasification occurs in multiple zones.
[d] Degasification occurs in one zone only.

MMtpy = million tons coal produced per year.
MM $ = million dollars
GW = gob wells.
XM = cross-measured boreholes.
GI = gas injection wells.
NPV = net present value at 10% discount rate of return.
IRR = internal rate of return.
HB = horizontal boreholes.
CVW = conventional vertical wells.

region examined. This agrees with the current practices employed at the Warrior and Central Appalachian region mines.

- Both mines examined in the Warrior Basin have several options for achieving better economic performance. The pipeline sales option offers the highest return, primarily due to the large quantity of gas utilized and the recovery of pipeline quality gas which eliminates expensive gas enrichment equipment and operating costs.
- The large gassy mine in the Central Appalachian Basin also has several options which provide significant increase in revenue with both gas turbines and the pipeline option. The pipeline option provides the highest return due to the large quantity of gas utilized and the recovery of high Btu gas from the Pocahontas No. 3 coalbed.
- Gas turbines seem to be more profitable at the gassy mines in the Northern Appalachian Basin. The pipeline sales option does not perform well because all degas systems are assumed to require gas enrichment before connecting into national transmission lines. This significantly increases the capital expenditure and operating costs.
- Utilization of gas recovered from the existing base case methane control system in the Illinois Basin mine does not offer positive economics, primarily due to the low volume of gas recovered.
- The Western region can utilize gas turbines to achieve positive economics. The pipeline option is unprofitable due to high pipeline construction costs.

Technology Specific Trends

- The analysis suggests that utilization of gas recovered from existing base case technologies offers high returns, with usually the lowest additional capital costs and minimal changes in normal methane control practices.
- Comparisons of the two methane end-use strategies reveal that on-site power generation with a gas turbine generally provides better economic performance than the pipeline sales option if the pipeline option requires gas enrichment. However, these results are highly dependent on the mine's ability to utilize all power generated on site and selling any excess power at the assumed rate of 50% of the electricity purchase price.
- Despite recovering a significant volume of gas, the pipeline option used at Mines 6 and 7 in the Northern Appalachian Basin does not offer favorable economics, mainly because it is assumed that all gas recovered from the degas system requires gas enrichment. The results improve dramatically if it is assumed that about half of the recovered gas is of pipeline quality and does not require enrichment.
- Multi-zone conventional vertical wells provide better economic performance at seven of the nine mines examined. This occurs as an outgrowth of the significant volume of gas that can be recovered from the three to six zones typically degassed. This technology usually requires significant capital outlay.
- Multi-zone technologies do not offer strong performance in areas where little or no overlying/underlying gas-bearing strata exist such as in the Illinois Basin (Mine 8).
- The developmental gas injection process is expected to offer significant emission reductions, but is burdened with high capital and operating costs. In spite of these advantages, the technology offers higher return at Mines 2 and 4 in the Warrior and Central Appalachian Basins, respectively. Due to the developmental nature of this technology, the performance and economic results should be viewed with caution.

Other Issues

- Barriers to coalbed methane development relate to the characteristics of the coal mining industry itself. Methane recovery projects often require significant capital investments which may not be forthcoming in times of declining profits, as experienced by the industry in recent years. Also, most coal companies place highest emphasis on coal production, limiting investment in coalbed methane recovery. Finally, given the uncertainty in the stability of future coal markets and declining natural gas sale prices, companies may be reluctant to invest in coalbed methane recovery.
- Legal issues over the ownership of coalbed methane resources are one of the most important barriers to coalbed methane recovery. Conventional gas and oil rights for the same tract of land are easily separated from mineral (coal) rights according to strata. However, there is no clear geological separation for coalbed methane resources. It is not generally clear whether the owner of the coal rights is also the owner of coalbed methane rights. This problem is recognized, and the U.S. Congress passed coalbed methane ownership legislation as part of the Energy Policy Act of 1992. This Act requires states to develop a statutory ownership program, or accept a mechanism that allows coalbed methane development to proceed in the absence of such a program by pooling coalbed methane interests (using an escrow account) until such time as ownership is resolved. In addition, recent court decisions indicate that a consensus is emerging that coalbed methane resources belong to the owner of the coal rights. However, on federal lands, most decisions have favored the oil and gas lease holder.

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The complete report, entitled "National Assessment of Environmental and Economic Benefits from Methane Control and Utilization Technologies at U.S. Underground Coal Mines," (Order No. PB98-118144-; Cost: $35.00, subject to change) will be available only from:

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