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UPDATE ON THE STATUS AND ACTIVITIES OF THE TASK FORCE ON THE ECONOMIC BENEFITS OF IMPROVING MINE SAFETY THROUGH THE EXTRACTION AND USE OF COAL MINE METHANE

CASE STUDY OF THE ECONOMIC IMPACT OF METHANE-RELATED EVENTS AT COAL MINES IN THE UNITED STATES OF AMERICA: CASE STUDY MINE B

Note by secretariat

I. INTRODUCTION

1. This paper is the result of a cooperative effort between the United States Environmental Protection Agency (US EPA) and the UNECE Ad Hoc Group of Experts on Coal Mine Methane and should be read in conjunction with ECE/ENERGY/GE.4/2007/8. It has been prepared by Mr. Ray Pilcher, Chairman of the Task Force on the Economic Benefits of Improving Mine Safety Through Extraction and Use of Coal Mine Methane, Ms. Charlee Bergamo, Environmental Scientist at Raven Ridge Resources, and Ms. Pamela Franklin, US Environmental Protection Agency.

II. MINE AND COAL RESOURCE INFORMATION FOR MINE B

2. Tables 1 and 2 below provide mine operations, coal resource, coal production, and methane-generation data for Mine B.

Table 1: Mine information

1 Mine Name			
Mine B			
2 Current Owner			
Intentionally Left Blank			
3 Status			
Active			
4 Location			
4.1 Country		United States	
4.2 Coal Basin/Region		Eastern Basin	
5 Mine Information Source: Keystone Coal Industry Manual (2005)			
Year of Initial Production	1969	**Number of Employees**	340
Mining Method	Longwall/Continuous	**Depth to Seam (m)**	152-457
6 Coal Resource Information Source: Keystone Coal Industry Manual (2005)			
Coal Seams Mined	Intentionally Left Blank	**Average Seam Thickness (m)**	0.6 – 3.0
Sulfur Content of Coal Produced (%)	*Minimum*	*Average*	*Maximum*
	0.50	0.75	1.18
Heating Value of Coal (KJ/kg)	*Minimum*	*Average*	*Maximum*
	31,934	34,750	35,427
Type of Coal	Bituminous	**Primary Market**	Steam, Metallurgical
Estimated Reserves Remaining (million metric tons)	NA	**Life Expectancy of the Mine**	2023

Table 2: Production, ventilation, and drainage data for Mine B

	2000	2001	2002	2003	2004
Coal Production (thousands metric tons/year)[a]	3,329	2,847	3,200	2,241	1,591
Estimated Total Methane Liberated (thousands m^3/day)[b]	453	419	447	396	322
Emission from Ventilation Systems: (thousands m^3/day)[b]	312	218	227	278	226
Estimated Methane Drained (thousands m^3/day)[b]	142	201	221	119	96
Estimated Specific Emissions (m^3/ton)[b]	45.1	48.7	46.3	58.4	50.2
Methane Recovered (thousands m^3/day)[c]	99.1	159	159	42.5	11.1

[a] MSHA Mine Yearly Reported Production Information, Data Retrieval System

[b] USEPA, 2004. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 1999-2003; MSHA ventilation data; 2004 data from CMM Emissions Inventory

[c] MSHA ventilation data.

III. MAJOR SAFETY ISSUES AT MINE B

3. To document the safety record of Mine B, the authors consulted the Data Retrieval System of the US Mine Safety and Health Administration (MSHA). In 2005, Mine B paid approximately $52,000 of the $86,000 in MSHA penalties assessed. As of the end of the first quarter of 2006, Mine B had been cited for accumulation of coal dust and inadequate rock dusting 115 times since the beginning of 2005. A number of other citations issued were concerned with maintenance of electrical equipment and firefighting equipment. Notably, 54 violations in 2005 were for roof fall protection issues. As of this report, there have been 19 injuries due to roof fall issues since the beginning of 2005. Most other accidents have involved handling of materials, such as lifting heavy objects, and slips and falls.

IV. SERIOUS ACCIDENTS

4. The most significant accident in Mine B's recent history has been the fire on 1 September 2003. The fire is believed to have been caused by a lightning strike to methane ventilation piping in a mined out area. Fortunately, the mine was idled for the Labour Day holiday, thus no fatalities or injuries resulted. This thermal event resulted in lengthy and costly idling of the mine. One continuous miner resumed operation in April of 2004[1], while longwall production resumed in mid-May of 2004. Initial plans were to avoid sealing the longwall; however, continuing ventilation problems forced the longwall area to be temporarily sealed to choke the remaining fire. The longwall was unsealed May 6, 2004 which resulted in mine evacuation for 72 hours[1].

[1] International Longwall News. http://www.longwalls.com. Additional citation information withheld to protect identity of mine.

V. OTHER INCIDENTS

5. There have been no other incidents of note.

VI. REGULATORY COSTS

6. Penalties were not assessed for the methane-related fire in 2003; only a 103(k) order was issued which requires the mine operator to obtain MSHA permission prior to re-entering the mine. Penalties assessed over the past 10 years totalled approximately $325,000 with $290,500 paid so far.[2]

VII. ECONOMIC LOSSES ASSOCIATED WITH SUSPENDING PRODUCTION OR CLOSING THE MINE

7. Much more significant than the cost of penalties has been lost productivity and costs associated with fire control and recovery due to methane outages, as described below.

(a) Estimated economic value of lost coal production from methane-related issues

8. Lost coal production is estimated by comparing quarterly coal production for the quarter in which idling occurred versus previous years' respective quarter with full production. This value is then multiplied by average open market coal price for the respective year to estimate annual losses due to curtailed coal production. Losses reported in this section are estimates based only on publicly known methane-related incidents and closures, and may not include all production losses due to high methane levels. The comparative basis used for full production against idle is the best estimate; although it is likely conservative as small, unpublicized instances of elevated methane may periodically slow down or halt production at the mine throughout the year. Table 3 summarizes the estimates for lost coal production during the 2003-2004 fire.

(b) Economic losses associated with mine closure

9. Mine B's owner is not a publicly-listed company, thus the only financial information released on Mine B comes from the owner in terms of royalties earned. The owner reported the idling of the mine had a minimal impact on its third quarter results because Mine B continued to ship coal from its inventory for several weeks after the mine shut down. Prior to the disruption, the owner's estimated fourth quarter 2003 royalty from the mine was approximately $1.6 million.[3] On 10 December 2003, the owner received a force majeure notice from Mine B's operator regarding the mine. The notice allows Mine B's operator to forego payment of the minimum royalties due under the lease terms until the mine resumed production. No information regarding the cost of lost coal or equipment was published.

[2] MSHA Data Retrieval System
[3] Owner News Release 23 October 2003. Additional citation information withheld to protect identity of mine.

Table 3: Economic value of lost coal production (Mine B)

Year	Lost Coal Production (million metric tons)	Average Coal Price[4] (US$ per metric ton)	Lost Coal Production (millions US$)
2003	1	29.04	35
2004	2	32.90	54
Total	3	-	89

[a] International Longwall News. http://www.longwalls.com. Additional citation information withheld to protect identity of mine.

10. World Coal published an article summarizing the fire-suppression efforts at Mine B using NOx foam injection. After numerous attempts were made to extinguish the fire with typical fire-fighting methods, Mine B contracted a foreign company that used exhaust gas from a jet engine to displace oxygen that was feeding the fire. World Coal reports these efforts ultimately failed and cost several million dollars. Mine B then contracted a drilling company to drill a borehole on top of the spot where the fire started, pumping the wet NOx formulation into the hole. This system successfully extinguished Mine B's fire and cost the mine approximately $150,000.[5]

11. In addition to lost equipment, lost reserves, and the expense of fire control, there was the impact Mine B's fire had on the steel industry. The Mine B mine is one of the most important in North America for supplying metallurgical coal, producing about 3 million tons of coal each year that is suitable for converting to coke. The coke shortage was severe enough that several steel companies cut production by half even as prices climbed to the highest level ever.[6] The shortage led to layoffs at a West Virginia steel company and curtailed production.

(c) Drainage and Ventilation Systems

12. Currently, Mine B utilizes a horizontal pre-mine drainage programme[7]. This system comprises two technologies – multilateral drainage networks, and a dual-well drilling and production system. A gas operator began a pre-drainage programme in 1998 when Mine B was operated by another company. In 2003, the gas operator reported that pre-drainage at Mine B would continue for another two to three years. In 2004, the drainage wells at the Mine B site recovered over 4 million m^3 of methane[8] which is sold to pipeline.

[4] Energy Information Administration, Annual Coal Report, Average Open Market Price of Coal by State and Underground Mining Method

[5] *World Coal*, 2005. Additional citation information withheld to protect identity of mine.

[6] Anton, John. Steel Markets: Causes and Factors Affecting Steel Prices in the Near and Medium Term. March 2005.

[7] USEPA, 2004. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 1999-2003.

[8] Voluntary Reporting for CMM Emissions Inventory 2004.

VIII. OPPORTUNITIES TO DEVELOP CMM USE PROJECTS

13. Although Mine B recovers methane, a substantial amount of methane drained is not recovered. In 2004, Mine B drained 26 million m^3 and recovered 4 million m^3. As a result of the costly thermal event spanning 2003 and 2004, it may be worth considering additional drainage at Mine B. Current, unrecovered methane drainage at Mine B could substantiate a profitable utilization project, potentially offsetting the cost of additional drainage at the mine. Using drainage information, the capital and operating costs for a number of CMM utilization project opportunities were studied, as well as net present value and internal rate of return. Projects include power generation plants (simple or combined cycle gas turbine or internal combustion engines) as well as pipeline injection. Costs were not differentiated according to the efficiency of the power generation equipment to be installed, and it should be noted that combined cycle and recuperated cycle systems would be more capital intensive. However, the gain in efficiency obtained with these systems would be more lucrative. Estimates of capital costs as well as operating and maintenance costs were calculated using standardized factors supplied by EPA. These standardized factors for various project options were used to calculate the capital cost for a project of a given size commensurate with the amount of gas available for utilization. Also to be noted is that total capital costs for power projects were estimated for both high installed cost and low installed cost cases, while operation and maintenance costs were assumed to be constant.

IX. UTILIZATION PROJECTS

14. The estimates below should be taken as order-of-magnitude estimates calculated to get a general indication of the profitability of additional CMM utilization projects at Mine B and to determine any potential offset in cost of improved drainage. A simple discounted cash flow analysis was done using an assumed discount rate of 10 per cent. Net present value and internal rate of return for prospective project options were based on high and low cost capital costs, operation and maintenance costs, and electricity and gas sales based on available drainage data (see Annex), with 2004 information summarized below in Tables 4 and 5.

15. Based on the electrical efficiencies of these power plant options[9], the amount of electricity to be produced was calculated and current industrial electricity prices[10] were used to calculate electricity sales. These estimates were made with current drainage; however, increased drainage to combat recent methane buildup issues may result in larger plants with applicable higher costs and profits.

16. In addition to power plant utilization, pipeline injection was considered. Again, EPA cost estimates were used to calculate the capital cost of a pipeline project as well as operation and maintenance costs. The last available drainage data was used to determine project size and the amount of gas to be sold. Up-to-date energy price data[10] was used to determine a natural gas price to calculate gas sales. The natural gas price used is the city gate price, not the wellhead price, as wellhead prices are not available in real time. The city gate price is slightly higher than

[9] Gas Turbine, http://en.wikipedia.org/wiki/Gas_turbine and Consumer Energy Council of America, Combustion Turbines, http://www.deforum.org/combustion-turbines.htm

[10] CMOP Documents, Tools, and Resources, Energy Prices, http://epa.gov/coalbed/resources/energyprices.html

what would be received by a gas seller due to additional incorporated pipeline and transportation costs. Table 5 shows the costs associated with installing a pipeline project, the annual operation and maintenance costs, and the projected gas sales based on 2004 drainage.

17. From this analysis, pipeline sales does not appear to be the best economic option with a net present value of $13.9 million and an internal rate of return of 77 per cent; however, logistically this option is desirable because Mine B has an existing pipeline project and owns the pipeline that connects to the county's transmission pipeline.[11] Combined cycle gas turbine power generation looks to be the most profitable utilization option for Mine B. Assuming a higher capital cost, a combined cycle gas turbine project has a net present value of $25.6 million and an internal rate of return of 60 per cent. For a lower assumed capital cost, the project has a net present value of $28.4 million and an internal rate of return of 81 per cent. Given the range of costs and resultant economic performance, a combined cycle gas turbine system would be more expensive to implement, but slightly more profitable than pipeline sales.

Table 4: Estimate of power plant costs and profits based on 2004 drainage (Mine B)

	Gas Turbine, Simple Cycle	**Gas Turbine, Combined Cycle**	**Internal Combustion**
Power Plant Size (MW)	15	22	15
Efficiency Assumed[a]	0.4	0.6	0.4
kWh/year (million)	131.38	197.08	131.38
Electricity Sales/Year (million US$)	0.11	10.64	7.09
Installed Cost High Estimate (million US$)	11.40	17.10	15.31
Installed Cost Low Estimate (million US$)	8.55	12.82	13.78
Operation and Maintenance Costs/year (million US$)	1.31	1.97	2.63
Net Present Value High Estimate (million US$)	2.6	25.6	8.1
Net Present Value Low Estimate (million US$)	4.7	28.4	9.1
Internal Rate of Return High Estimate	17%	60%	27%
Internal Rate of Return Low Estimate	26%	81%	31%

[a] Gas Turbine, http://en.wikipedia.org/wiki/Gas_turbine and Consumer Energy Council of America, Combustion Turbines, http://www.deforum.org/combustion-turbines.htm

[11] USEPA, 2004. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 1999-2003

Table 5: Pipeline project costs and sales based on 2004 drainage (Mine B)

Annual Gas Drainage (million m^3)	Capital Gathering Cost (million US$)	Gathering O & M Costs/year (million US$)	Capital Processing Cost/Volume (million US$)	Processing O & M Costs/year (million US$)	Capital Compression Cost (million US$)	Compression O & M Costs/year (million US$)
26	1.54	0.23	1.62	0.27	0.84	0.03
Capital Transport Cost (million US$)	**Transport O&M Costs/year (million US$)**	**Capital Injection Into NG Pipe (million US$)**	**Total Capital (million US$)**	**Gas Sales per Year (million US$)**	**Net Present Value (million US$)**	**Internal Rate of Return**
3.00	0.12	0.50	7.50	8.72	13.9	77%

Table 6: Summary of estimated costs due to methane-related fire at Mine B

Year	MSHA Penalties Paid (US$)	Lost Coal Production (million metric tons)	Lost Coal Production (millions US$)	Additional Costs	
2003	$11,186	1	35	Fire suppression[a] NOx foam Jet engines	$150,000 Several million $[b]
2004	$41,314	2	54		
Total	$52,500	3	89		

[a] Fire suppression costs cover the suppression of the event spanning 2003 to 2004.

[b] *World Coal*, 2005. Additional citation information withheld to protect identity of mine.

X. SUMMARY

18. Mine B lost a significant amount of production due to the methane fire of 2003-2004, resulting in an estimated loss of over $88 million. Additional losses were not reported, such as those from lost coal reserves and equipment; however, fire suppression efforts reportedly cost several million dollars. Fortunately, injuries and deaths were avoided in this incident due to the holiday break; however, increased methane control can only result in a safer mine.

19. Just as in the case of Mine A (ECE/ENERGY/GE.4/2007/8), MSHA penalties have a negligible impact on the Mine B's finances compared to the losses the methane-related fire has caused. Penalties over the last ten years amount to only $325,000. The most significant impacts resulted from lost production.

20. Additional conclusions for both Mine A and Mine B are included in the Summary to the Case Study for Mine A (ECE/ENERGY/GE.4/2007/8).

XI. RECOMMENDATIONS

21. Increasing the capacity of the methane drainage system at Mine B may be a prudent investment from an overall operations standpoint as well as from a safety perspective. Mine B practises gas drainage and recovery, yet it is still susceptible to methane-related fires, as illustrated by the severity and duration of the thermal event in 2003-2004. The potential profitability of utilizing more of the methane that is currently being drained could provide capital for additional drainage, and improving safety while relying less on ventilation systems.

ANNEX

MINE B: PROJECT ECONOMICS FOR POTENTIAL COAL MINE METHANE PROJECTS

Table A-1: Annual methane drainage and potential CMM power plant size at Mine B (assuming 100 per cent conversion efficiency)

Year	Mm^3/yr	MJ/s (MW)
2000	15.4	19
2001	15.4	19
2002	23.1	28
2003	27.7	33
2004	31.3	37

Table A-2: Summary table of cost and profit for CMM power plant options for Mine B, 2000-2004

Gas Turbine, Simple Cycle (Efficiency 0.4[a])		Installed Costs (US$)		kWh/year	Operation and Maintenance Costs/Year (US$)	Electricity Sales/Year (US$)
Year	Plant Size MW	High Estimate	Low Estimate			
2000	7.40	12,761,910	10,208,048	64,845,900	907,843	3,501,679
2001	7.41	12,768,523	10,213,337	64,879,500	908,313	3,503,493
2002	11.05	8,399,588	6,299,691	96,816,300	968,163	5,228,080
2003	13.29	10,102,716	7,577,037	116,447,100	1,164,471	6,288,143
2004	15.00	11,398,647	8,548,985	131,384,400	1,313,844	7,094,758

[a] Gas Turbine, http://en.wikipedia.org/wiki/Gas_turbine and Consumer Energy Council of America, Combustion Turbines, http://www.deforum.org/combustion-turbines.htm

Table A-3: Summary table of cost and profit for CMM power plant options for Mine B, 2000-2004 (continued)

Gas Turbine, Combined Cycle (Efficiency 0.6[b])		Installed Costs (US$)		kWh/year	Operation and Maintenance Costs/year	Electricity Sales/Year (US$)
Year	Plant Size MW	High Estimate	Low Estimate			
2000	11.10	8,438,850	6,329,138	97,268,850	972,689	5,252,518
2001	11.11	8,443,223	6,332,417	97,319,250	973,193	5,255,240
2002	16.58	12,599,382	9,449,536	145,224,450	1,452,245	7,842,120
2003	19.94	15,154,075	11,365,556	174,670,650	1,746,707	9,432,215
2004	22.50	17,097,970	12,823,477	197,076,600	1,970,766	10,642,136

[a] Gas Turbine, http://en.wikipedia.org/wiki/Gas_turbine and Consumer Energy Council of America, Combustion Turbines, http://www.deforum.org/combustion-turbines.htm

Table A-4: Summary table of cost and profit for CMM power plant options for Mine B, 2000-2004 (continued)

Internal Combustion (Efficiency 0.4[a])		Installed Costs (US$)		kWh/Year	Operation and Maintenance Costs/year (US$)	Electricity Sales/Year (US$)
Year	Plant Size MW	High Estimate	Low Estimate			
2000	7.40	8,150,153	7,365,488	64,845,900	1,296,918	3,501,679
2001	7.41	8,154,376	7,369,304	64,879,500	1,297,590	3,503,493
2002	11.05	11,284,183	10,156,870	96,816,300	1,936,326	5,228,080
2003	13.29	13,572,202	12,216,311	116,447,100	2,328,942	6,288,143
2004	15.00	15,313,182	13,783,363	131,384,400	2,627,688	7,094,758

[a] Gas Turbine, http://en.wikipedia.org/wiki/Gas_turbine and Consumer Energy Council of America, Combustion Turbines, http://www.deforum.org/combustion-turbines.htm

Table A-5: Pipeline injection cost and profit summary (Mine B), 2000-2004

Year	Mm^3/d	Capital Gathering Cost (US$)	Gathering O&M Costs (US$)	Capital Processing Cost (US$)	Processing O&M Costs (US$)
2000	0.0423	752,094	177,367	1,516,032	207,612
2001	0.0423	752,484	177,458	1,516,818	207,720
2002	0.0632	1,132,838	167,250	1,195,278	198,470
2003	0.0760	1,362,536	201,162	1,437,636	238,712
2004	0.0857	1,537,316	226,966	1,622,050	269,333

Table A-6: Pipeline injection cost and profit summary (Mine B), 2000-2004 (continued)

Year	Capital Compression Cost (US$)	Compression O&M Costs (US$)	Pipeline Length (km)	Capital Transport Cost (US$)	Transport O&M Costs (US$)	Capital Injection Into NG Pipe (US$)
2000	463,397	25,989	40	2,499,776	124,989	500,000
2001	463,637	26,002	40	2,499,776	124,989	500,000
2002	619,939	19,401	40	2,999,731	124,989	500,000
2003	745,640	23,335	40	2,999,731	124,989	500,000
2004	841,287	26,328	40	2,999,731	124,989	500,000

Table A-7: Pipeline injection cost and profit summary (Mine B), 2000- 2004 (continued)

Year	Gas Sales (million m^3)	Gas Sales (US$)
2000	15	4,302,990
2001	15	4,305,220
2002	23	6,424,455
2003	28	7,727,100
2004	31	8,718,297
