ELSEVIER

Environmental Science & Policy 5 (2002) 397–409

Environmental Science & Policy

www.elsevier.com/locate/envsci

Engineering and economic evaluation of gas recovery and utilization technologies at selected US mines

D.A. Kirchgessner[a,*], S.S. Masemore[b], S.D. Piccot[b]

[a] United States Environmental Protection Agency, Mail Drop E305-02, Research Triangle Park, NC 27711, USA
[b] Southern Research Institute, P.O. Box 13825, Research Triangle Park, NC 27709-3825, USA

Abstract

Methane liberated in underground coal mines is a severe safety hazard to miners. It is also a major contributor to the build-up of greenhouse gases in the global atmosphere. This report presents an engineering and economic evaluation of several methane recovery and end-use technologies which can remove, purify, and utilize methane from coal seams. The methane recovery technologies evaluated are widely applicable to US underground mines, and include conventional systems such as vertical extraction wells, gob area wells, horizontal boreholes, and cross-measure boreholes. More advanced and developmental technologies, such as the nitrogen injection process, have also been examined. Methane utilization technologies examined include the use of gas turbines for the generation of on-site power, compression and transport systems needed to sell the gas to a national distributor, and the generation of electrical power for off-site sale. The applicability and performance of each technology were assessed at nine representative coal mine sites, and the economic and emissions reduction performance between existing and alternative recovery operations were examined.
Published by Elsevier Science Ltd.

Keywords: Methane recovery; Coal mines; Economic evaluation; Technological evaluation; Greenhouse gas

1. Introduction

Within the US, the American Geophysical Union (1999) has recently acknowledged both the anthropogenic contribution to climate change and the prudence of developing strategies for emissions reductions, carbon sequestration, and adaptation. In response to the Kyoto agreement representatives of many other countries are espousing these approaches as well. Hansen et al. (2000) noted that since they believe the majority of warming in recent decades has been caused by non-CO_2 greenhouse gases, CH_4 would be a good candidate for future reductions. Because of its short atmospheric residence time Cicerone (2000) concurs with this approach. The mitigation of CH_4 from coal mines has been recommended for some time as a means of reducing the effects of climate change (Hogan et al., 1991; Intergovernmental Panel on Climate Change (1996); Law and Nisbet, 1996; Hayhoe et al. (1999)) use modeling results to show that controlling CH_4 is more cost-effective than controlling CO_2 alone.

Methane emissions from the coal industry are produced by active, inactive, and abandoned underground mines, surface mines, and post-mine handling activities. Underground mines produce the vast majority of emissions, however, and are most amenable to control. The US Environmental Protection Agency (EPA) has estimated that methane emissions at large, gassy, underground mines (defined as mines having annual coal production >0.454 million tonnes and methane emissions of >15.6 m^3/tonnes of coal mined) could be reduced profitably by an amount equal to 32–44% of emissions from all underground mines by the year 2000, and by an amount equal to 40–45% of emissions by 2010 (USEPA, 1993).

Guidelines for selecting mines and control options which will allow the control of CH_4 cost-effectively are currently lacking in the literature. This paper presents the results of a national engineering and economic assessment of methane recovery and utilization systems at top emitting coal mines. It evaluates the economics of methane end-use technologies at mines that currently employ gas recovery systems and vent the recovered gas, as well as the mines that do not use recovery systems.

2. Methods

2.1. General

Mine ventilation emissions data indicate that 85% of the total methane emitted from mine shafts is from 50

* Corresponding author. Tel.: +1-919-541-4021; fax: +1-919-541-7885.
E-mail address: kirchgessner.david@epa.gov (D.A. Kirchgessner).

1462-9011/02/$ – see front matter. Published by Elsevier Science Ltd.
PII: S1462-9011(02)00047-3

underground mines (USDOE, 1996). Currently, about 30 mines employ methane recovery systems as standard operating practice. Of these, at least 10 gassy mines operated by Jim Walter Resources Inc., Consolidation Coal Co., and US Steel Mining Co. are profiting from the sale of recovered gas or by using it to meet on-site energy requirements. The remaining mines are venting the recovered gas without utilization, and are viewed as candidate sites for examining the profitability of utilizing mine gas.

Nine mines which represent operations in the Black Warrior basin (Mines 1 and 2), central Appalachian (Mines 3 and 4), northern Appalachian (Mines 6, 7, and 8), Illinois basin (Mine 8), and Western regions (Mine 9) are selected for the study. These "model" mines are similar to actual operations in the following ways: (1) similar coal production rates and methane emission levels, (2) similar coal stratigraphy to actual mines located in the same geographic region, and (3) similar on-site power requirements. Specifically, they are assigned the same location and the name of the mined coal seams, the gas content of the mined seams and the surrounding strata, the depth of mining, and the method of mining as their counterpart mines. Table 1 summarizes these and other key properties of the nine mines.

Each model mine is further defined by a methane control strategy which is representative of applications currently employed by counterparts in their regions. This consists of mine ventilation systems as the primary source of methane control in addition to gas recovery systems, which represents the practice employed at a few gassy locations. The types of gas recovery systems considered include the commonly utilized gob wells, horizontal boreholes, and conventional vertical wells (gob wells drain methane from the collapsed strata that longwall mining ultimately leaves in its wake; horizontal boreholes drain methane from the coal seam in advance of mining from within the working mine: vertical boreholes drain methane from the coal and surrounding strata in advance of mining from the surface). This designation of current practice is referred to as the "base case" methane control level, and forms the benchmark against which the performance and cost of alternative technologies are measured. Alternative recovery systems include those that are more advanced than the base case practices, unless the technology is already in use, or some technical limitation exists which prohibits its use. For example, gob degasification systems are not examined at room and pillar mines, and the use of cross-measure boreholes are examined in a very select group of mines due to their limited use in US coal mines. Table 1 lists the base case, alternative methane control technologies, and the volume of methane emitted and recovered at each mine.

For each model mine two separate gas utilization strategies are examined: on-site power generation with gas turbines and sales to national gas transmission lines. These end-use technologies are selected primarily because they have been successfully employed at coal mines, and they show the greatest promise of being used at other sites. With gas turbines, low to high heating value gas can be used to generate power on-site to meet each mine's electricity requirements. If the gas turbines generate more power than required on-site, the excess power can be sold to an off-site facility at a rate lower than the mine's electricity purchase price. With the pipeline option, gas purification systems are specified to purify low and medium heating value gas in selected mining regions. The purified gas is compressed and connected to pipeline distribution systems, and revenue is recognized from the sale of the recovered gas.

For each base case and alternative degasification/utilization scenario, engineering analyses are conducted to identify design specifications for the coal mining operation, recovery systems, and methane utilization technologies. The resulting engineering data are combined with cost parameters to determine the annualized cost for capital expenditures, and operating and maintenance costs. A discounted cash flow analysis is then performed to determine the net present value (NPV) and internal rate of return (IRR) for the base case and the alternative operations. Competing degasification/utilization system combinations are analyzed by comparing the incremental differences between the NPV and the IRR earned using base case degasification technologies with the NPV and IRR achieved using alternative, higher performing technologies and utilization systems. The technology option which offers positive values provides better economic incentives than the base case.

2.2. Design and economic assumptions

Design specifications, performance parameters, and economic analysis procedures for the coal production, gas recovery, and gas utilization system components were developed with the direct assistance of coal mining and gas recovery system experts including the John T. Boyd Company, the Amoco Production Company, Resource Enterprise Incorporated, and Energy Ingenuity Company. The US EPA, the US Bureau of Mines (BOM), and the US Steel Mining Company provided additional inputs. Key design assumptions are discussed below.

2.2.1. Coal production specifications

Five categories of coal production parameters are characterized: reserve and recovery estimates, mining and operating equipment requirements, rate of mining, ventilation requirements, and on-site power demand. Table 2 summarizes the values assigned to each parameter.

2.2.2. Degasification system parameters

The design parameters and cost factors for each control technology are determined through an investigation of mines currently employing these technologies. This includes documentation on gob wells, horizontal boreholes, and conventional vertical wells from the Jim Walter Resources and Consolidation Coal Company mines in Alabama and Virginia, respectively (Dixon, 1987; Mills and

Table 1
Model mine description

	Mine number								
	1	2	3	4	5	6	7	8	9
Location									
Basin/region	Warrior	Warrior	Central Appalachian	Central Appalachian	Northern Appalachian	Northern Appalachian	Northern Appalachian	Illinois	Western countries
State	AL	AL	WV	VA	PA	PA	WV	IL	CO
County	Jefferson	Tuscaloosa	Raleigh	Buchanan	Indiana	Greene	Monongalia	Franklin	Las Animas
Mined seam	Mary Lee	Mary Lee	Beckley	Pocahontas no 3	Freeport	Pittsburgh	Pittsburgh	Herrin no 6	Maxwell
Mining method[a]	LW	LW	R&P	LW	R&P	LW	LW	LW	LW
Coal production (MMtpy)[b]	1.1	2.2	0.9	1.6	0.9	2.7	2.7	2.7	1.4
CH_4 emissions (MMcmy)[c]									
From ventilation system	15.5	179.9	19.7	74.4	11.4	60.0	38.3	21.7	52.7
From degasification system	0	69.3	0	72.4	0	22.7	23.0	10.3	26.2
Total	15.5	249.2	19.7	146.8	11.4	82.7	61.2	32.1	79.0
Degas technology[d]									
Base case	None	GW&HB	None	GW&HB	None	GW	GW&HB	GW	GW&HB
Alternative									
GW	Y					Y		Y	
XM	Y							Y	
HB	Y		Y		Y	Y	Y	Y	
CVW	Y	Y	Y	Y	Y	Y	Y	Y	Y
GI	Y	Y	Y	Y	Y	Y	Y	Y	Y
GW/HB	Y	Y		Y		Y		Y	Y
XM/HB	Y						Y	Y	
GW/HB/CVW	Y	Y		Y			Y	Y	Y
GW/HB/GI		Y		Y					Y
Utilization technology	None								
Base case	Power generation with gas turbines/sale to pipeline								
Alternative									

[a] LW: longwall; R&P: room and pillar.
[b] MMtpy: million metric tonnes per year.
[c] MMcmy: million cubic meters per year.
[d] GW: gob wells; XM: cross-measure; HB: horizontal boreholes; CVW: conventional vertical wells; GI: gas injection wells.

Table 2
Key coal production related data

Coal reserve and recovery parameters		
Seam depth	Meter	213–610
Seam height	Centimeter	152–244
Reserve density (clean (C) coal)	Ctonnes/hectare m	13606
Reserve density (raw (R) coal)	Rtonnes/hectare m	17004
Mine life	Years	15
Area mined	Hectare	805–2703
Mining equipment specifications		
Longwall equipment		
Production rate	Ctonnes per shift-unit	1814–4082
Operating shifts	Units	0–1
Duration of mining	Shifts per day	0–2.4
Advancement rate (duration)	Days per year	0–200
Advancement rate (area mined)	1000 m^2 per year	0–1013
Continuous miner		
Production rate	Ctonnes per shift-unit	302–529
Operating shifts	Units	3–5
Duration of mining	Shifts per day	5–9
Advancement rate (duration)	Days per year	240
Advancement rate (area mined)	1000 m^2 per year	144–547
Rate of mining parameters		
Cumulative advancement rate	1000 m^2 per year	482–1262
Panel length	Meter	3048
Panel width	Meter	244–274
No. of panels mined	Panels per year	0.78–1.68
Ventilation requirements		
Normal ventilation	1000 m^3 air/min	7.65–10.20
Maintain 0.5% CH_4	1000 m^3 air/min	4.33–68.5
On-site power demand		
Operating demand	1000 kWh per year	22531 63389
Continuous demand	1000 kWh per year	18549–51900

Stevenson, 1991). Other sources of data include reports detailing cross-measure/horizontal borehole degasification at the Cambria 33 mine in Pennsylvania, gob well/horizontal borehole degasification at the Soldier Canyon mine in Utah, and numerous documents available from the BOM on methane control technologies at US underground mines (Baker et al., 1986, 1988; Campoli et al., 1983; Carter, 1990; Diamond, 1995; Ely and Bethard, 1989; Gabello et al., 1981; Garcia and Cervik, 1985; Hobbs and Winker, 1990; Kravits et al., 1985; Malinchak and Sturgill, 1987). An effort was also made to identify site specific data where available; however, where such data did not exist (i.e. the Illinois basin mine), engineering judgement is used to best represent the area. For the gas injection process, currently available nitrogen generation, compression, and separation technologies are identified. Design and cost information are then assembled to best represent this developmental technology. Table 3 lists the design and cost factors assigned to each methane control system.

2.2.3. *Gas recovery rate and gas quality assumptions*

The gas recovery rates for the base case control systems are assumed to be the same as the volume of gas emitted from the counterpart mines. For the alternative systems, gas in place (GIP) reserves are estimated for each geographic region where model mines are located. This is accomplished by characterizing the stratigraphic makeup of the gas bearing strata surrounding the mined seam, specifically the surrounding coal seams, their gas contents, and seam thicknesses. Table 4 summarizes the GIP values assigned to the model mines.

The performance of degasification technologies and gas recovery rates can be highly variable depending on where the wells or boreholes are drilled, the gas content of the coal seams, the stimulation and production methods used, the number and thickness of coal seams degasified, and the duration of gas production. The gas recovery rates for gob wells, cross-measure boreholes, horizontal boreholes, and conventional vertical wells are assigned based on performance characteristics reported by the BOM, EPA, and the coal mining industry. For the nitrogen gas injection technology, an overall recovery rate of 80% is used. Table 5 lists the volume of gas expected to be recovered for each mine.

2.2.4. *Gas utilization system parameters*

Two forms of utilization methods are considered: (1) sale to pipelines, and (2) on-site power generation with gas turbines. For the pipeline option, costs for gas enrichment and

Table 3
Methane degasification system specifications and costs

Gob wells		Conventional vertical wells	
Design specifications			
Well spacing (first well, m)	91.4–121.9	Duration of gas production (years)	225–482
Well spacing (between wells, m)	304.8–914.4	Total area degasified in 5 years (hectare)	19
No. of wells drilled per panel	2–11	Well spacing (hectare)	25 August
No. of wells drilled per year	3–16	No. of wells drilled per 5 years	6 March
Casing diameter (cm)	23–30	No. of wells converted into gob wells	1
Drilling depth (m)	175.3–602.0	No. of zones completed—single zone completion	6 February
Exhaust pump size (kW)	[a]	No. of zones completed (multiple-zone completion)	25–400
Compressor size (kW)	[b]	Water production per well (bbl[c] per day)	12,802–33,528
Gathering lines (m)	5486.4–10,363.2	Length of gathering lines (m)	1524
Main line W per gas turbine option (m)	1524	Length of main line (with gas turbine option, m)	1.61–37.0
Main line W per pipeline option (km)	1.6–37.0	Length of main line (with pipeline option, miles)	[b]
Gas enrichment		Compressors (kW)	5, 6, and 7
Model mines requiring enrichment	All	Model mines requiring gas enrichment	5
N_2, O_2 separation technology	Pressure swing absorption		
CO_2 separation technology	Membrane		
Capital costs			
Site preparation (US$ per well)	13,000–36,800	Project planning, site leveling, cleanup, etc. (US$ per well)	26,000
Well drilling, casing, etc. (US$/m per well)		Land development (leasing, roads, power, fences; US$ per well/m; US$/hectare)	679.54–1892.83
Well setting, welding, etc. (US$ per well)	119.75–247.70	Drilling, coring, casing, cementing, etc. (US$ per well/m)	344.49
Well surface equipment	5047–13,088	Installation, wellhead equipment, valves, meters, etc.(US$ per well)	47,000
Well exhaust pump (US$)	[c]	Exploratory corehole testing (US$ per well)	97,500
Well compressor (US$)	[d]	Stimulation and perforation (US$ per well per zone)	47,000
Gathering lines (US$/m)	49.21	Utilities, etc. (US$ per well)	12,000
Main line for pipeline sales (US$/km)	341,827–497,203	Water disposal facility (US$/1000 l)	39.63
Gas enrichment equipment		Install treatment pond (US$ × 10^{-3} l)	105.68
PSA units (US$/Mcmd)	15,184	Water monitoring station (US$ × 10^{-3} l)	52.84
Membrane units (US$/Mcmd)	6356	Additional water disposal costs (US$)	9800
Other equip. (analyzers, flow meters, valves, etc. US$ per well)	13,673	Compressors (US$)	[d]
		Gathering lines (US$/m)	49.21
		Main line for pipeline sales (US$/km)	341,827–497,203
Annual costs			
CH_4 sampling/maintenance (US$ per well)	17,000	Surface operation (daily operation and well maintenance, US$ per well)	10,600
Well oper./maintenance (US$ per well)	16,500–17,500	Water monitoring and treatment (US$/bbl)	0.05
Compressors (US$/Mcm)	1.06	Compressor operating and maintenance (US$ × 10^{-3} m^3)	1.06
PSA units (US$/Mcm)	7.06		
Membrane units (US$/Mcm)	12.01		
Cross-measure boreholes		**Horizontal boreholes**	
Design specifications			
Borehole spacing (first 182.9 m, m)	30.5	Borehole spacing (m)	61
Borehole spacing (remaining length, m)	61	Borehole length (m)	305
Borehole length (m)	121.9	No. of boreholes drilled per panel	24–52
No. of boreholes drilled per panel	53–61	No. of boreholes drilled per year	30–86
No. of boreholes drilled per year	41–80	Length of 8″ underground polyethylene pipe (m)	4572–10,363
Length of 8″ underground polyethylene pipe (m)	4877–7925	Total no. of vertical holes drilled	2
Total no. of vertical holes drilled	2	No. of vertical holes in production each year	1
No. of vertical holes in production each year	1	Length of gathering lines on surface (m)	1265–1981
Length of gathering lines on surface (m)	1890–1494	Length of main line (with turbine option, m)	1524
Length of main line (with turbine option, m)	1524	Length of main line (with pipeline option, km)	1.61–37
Length of main line (with pipeline option, km)	4.8–5.3	Model mines requiring gas enrichment	5, 6, and 7
Model mines requiring gas enrichment	All		

Table 3 (*Continued*)

Gob wells		Conventional vertical wells	
Capital costs			
Borehole drilling equipment (US$)	84,762	Electrohydraulic drill (US$)	250,000
Other drilling equipment (US$ per boreholes)	618	Borehole drilling equipment (pumps, mixers, valves, etc., US$)	42,954
Gas collection system (US$ per boreholes)	516	Other drilling equipment (drill string accessories, US$ per borehole)	18,380
Gas collection system (water trap, fittings) (US$)	3370	Gas collection system (US$ per borehole)	1971
Gas transmission system			
Polyethylene pipe (US$/m)	28.77	Polyethylene pipe (US$/ft)	28.77
Polyethylene pipe (US$ per boreholes)	505	Pipe accessories (US$ per borehole)	505
		Gas sensing system (US$ per borehole)	5649
		Gas sensing system (computers, etc., US$)	33,507
Annual costs			
Drill operation (drill setup, drilling and maintenance, etc.)	8537	Drill operation (US$ per borehole)	8537
		Air compressor overhaul (US$)	2113
Gas injection wells			
Design specifications		Capital costs	
Ratio of injection wells to production wells	1:04	Nitrogen generation—membrane facility (US$ $\times$ 10^{-3} m^3/inj. Well)	33,545
No. of injection wells drilled per 5 years	2–6	Nitrogen compressor (US$)	d
Nitrogen generation technology	Membrane		
		Annual costs	
Nitrogen injection rate (MMcfd)	5	Nitrogen generation—membrane facility (US$ $\times$ 10^{-3} m^3 per inj. Well)	2.47
Model mines requiring gas enrichment	All	Nitrogen compressor operating and maintenance (US$ $\times$ 10^{-3} m^3)	1.06

[a] 3.55 + 1.096E − 9 gas flow (m^3/h) × depth (m).
[b] 1.38E −5 × 0.2832 gas flow$^{0.876}$ (m^3 per day) × 0.06805 pressure$^{0.876}$ (atm).
[c] 0.741 gas flow$^{0.276}$ (m^3/h) × depth$^{0.276}$ (m).
[d] 93. 616 + 1.1E −6 × gas flow (ft^3 per day) × 0.06805 pressure (atm).
[e] 1 bbl = 42 U.S. gallons/158.97 liters.

Table 4
Gas in place reserve estimates

Model mine	Coal seam stratigraphy	Weighted average gas content (m^3 gas/tonne coal)	Net pay thickness (m)	GIP[a], all coal seams (m^3)	GIP[a], mined coal seam (m^3)
1	Cobb group, Pratt group, Mary Lee group[b], Black Creek group	8.43	8.5	73.3	28.6
2	Cobb group, Pratt group, Mary Lee group[b], Black Creek group	8.43	8.5	118.3	45.8
3	Sewell, Beckley[b], Pocahontas no. 3	10.52	4.4	53.3	23.7
4	Jawbone, Lower Seaboard, War Creek, Lower Horsepen, Pocahontas nos. 4, and 3[b]	11.39	8.5	131.1	41.0
5	Sewickley group, Pittsburgh group, Freeport group[b], Kittanning group, Brookville/Clarion group	6.34	6.2	47.0	12.7
6	Waynesburg group, Sewickley group, Pittsburgh group[b], Freeport group, Kittanning group, Brookville/Clarion group	3.93	14.2	121.5	46.8
7	Waynesburg group, Sewickley group, Pittsburgh group[b], Freeport group, Kittanning group, Brookville/Clarion group	5.40	7.6	80.7	29.8
8	Danville, Herrin nos. 6[b], 5A, and 5	2.31	6.8	25.7	12.9
9	Raton formation, Vermejo formation[b]	7.65	6.1	34.2	20.8

[a] Gas in place.
[b] Mined coal seam.

Table 5
Gas recovery rates[a] (million m^3 per year)

	Model mine								
	1	2	3	4	5	6	7	8	9
Base case degasification[b] systems									
None	0		0		0				
GW						22.7		10.3	
GW&HB		69.3		72.4			23.0		26.3
Alternative degasification[b] systems									
GW	5.4					22.7		10.3	
XM	5.4					22.7		10.3	
HB	14.3		11.8		6.3	23.4		6.4	
CVW[c]	18.6		15.4		8.2	30.4		8.4	
CVW[d]	47.6	76.9	34.6	85.2	30.6	79.0	52.4	16.7	22.2
GI[c]	22.9		19.0		10.1	37.4		10.3	
GI[d]	58.6	94.7	42.6	104.9	37.6	97.2	64.5	20.5	27.3
GW/HB	19.7	69.3		72.4		46.1	23.0	16.8	26.3
XM/HB	19.7					46.1		16.8	
GW/HB/CVW[c]		99.1		99.0			42.4		39.8
GW/HB/CVW[d]		146.2		157.6			75.4		48.4
GW/HB/GI[c]		105.9		105.1			46.8		42.9
GW/HB/GI[c]		163.8		177.3			87.5		53.6

[a] Gob wells and cross-measure boreholes are assumed to produce low heating value (65–75% CH_4 concentration), horizontal boreholes and conventional vertical wells produce high heating value gas (>95% CH_4 concentration), and nitrogen injection wells produce medium quality gas (75% CH_4 concentration).
[b] GW: gob wells; XM: cross-measure; HB: horizontal boreholes; CVW: conventional vertical wells; GI: gas injection wells.
[c] One-zone completion, degasification occurs in the primary mined seam.
[d] Multiple-zone completion, degasification occurs in all gas bearing strata.

processing equipment (if required), and secondary gas compressors to achieve pipeline pressure were accounted for.

Gas turbines are most useful when the quality of the recovered gas is variable (i.e. low to medium heating value mine gas). Comprehensive specifications and costs for the gas turbines were developed through evaluation of equipment catalogs of Solar Turbines Inc. Six turbine models are selected to accommodate the type of gas expected to be recovered at the model mines. The turbine models vary in size and can deliver 1.0–10.7 MW power. For each methane control system, a turbine model is selected by calculating the inlet fuel load (i.e. volume of the recovered gas multiplied by the heating value). Parallel interfacing with the mine's existing power grid is accounted for to fully utilize the capacity of the power generated from the turbines. Backup power cost was specified to represent the additional charges incurred by the mine from electric utility companies during the periods when the on-site generator is not functioning. It is assumed that 2% of the mine's on-site power accommodated by the turbines is supplied as backup power at a rate equivalent to two times the electric purchase price.

In situations where more excess power is generated than the amount required at the mine site, the additional power can be transported to commercial power plants and sold for profit. Such systems may require parallel interfacing with commercial power grids, and detailed evaluation and planning may be required. The success of profiting from the excess power is highly dependent on the interest shown by the power plants to purchase the mine generated excess power. It is assumed that all mines producing excess power are capable of distributing to outside customers, and the revenue generated from this sale is equivalent to 50% of the electricity purchase price.

2.2.5. Financial assumptions

An economic model was developed to facilitate the cost analysis of coal mining production factors and methane degasification and utilization technology costs. The model uses a discounted cash flow methodology to calculate the NPV of each project. The discount factor, assumed to be 10%, is the minimum rate of return that may be viewed by a mine operator as acceptable. If the NPV of a base case or alternative degasification system coupled with a utilization technology is positive, then the sum of the discounted net income or savings is greater than the capital outlays. In such cases, the project has a positive impact on the profitability of the company. In general, a project with the highest positive or least negative NPV offers the most favorable economic results.

The IRR of a project represents the discount rate at which the present value of the project is zero. It is determined through a trial and error procedure or by iteratively solving for the discount rate at which the NPV reaches zero. If the IRR is greater than the discount rate of return, the project will add to the profitability of the business.

Table 6 lists the financial parameters assumed in the study. A project life of 15 years is assumed. Three forms of revenue are accounted as income generators: (1) sale of gas with the pipeline option, (2) sale of electricity when excess power is generated from gas turbines, and (3) mine power savings realized from on-site power generation. Inflation in both

Table 6
Key financial inputs

Model mine	Coal sales price (US$/tonne)	Wellhead gas sales price (US$ × 10^{-3} m^3)	Electricity purchase price (US$/kWh)
1	49.11	102.40	0.040
2	49.11	102.40	0.040
3	38.02	70.62	0.045
4	40.90	64.27	0.045
5	31.80	67.44	0.063
6	31.80	68.50	0.063
7	31.88	70.62	0.045
8	28.82	74.51	0.044
9	22.88	51.91	0.035
Discount rate of return (%)			10
Mine productivity life (years)			15
Gas royalty and severance tax (%)			15
Degasification tax impact (%)			0
Federal income tax rate (%)			34
State income tax rate (%)			7
Gas depletion allowance (%)			0
Inflation rate (capital costs, %)			4
Inflation rate (operating costs, %)			4
Inflation rate (selling prices, %)			4

operating costs and income is assumed to increase at a rate of 4% annually. A straight line depreciation is applied to all coal mining, degasification, and utilization system capital costs; depletion allowance is not accounted for in the study. A federal income tax rate of 34%, state income tax rate of 7%, and gas royalty tax and severance tax equal to 15% of the revenue generated from gas sales are assumed in the study. A degasification tax impact of 0% is used because Section 29 tax credit is not applicable to projects examined in the study.

3. Results

3.1. Black Warrior basin

Two longwall mines, operating in Alabama, represent coal mining operations in the Black Warrior basin. Mine 1 is the smaller of the two operations, and produces 1.1 MMtpy (million metric tonnes per year) coal from the Mary Lee coalbed. It does not employ degasification systems to control methane emissions, and emits about 15.5 MMcmy (million cubic meters per year) methane from ventilation shafts. The economic results suggest that no degasification technology attains a positive incremental NPV with the gas turbine option. All systems offer poor profits because of the low quantity of gas recovered and high drilling costs. However, the pipeline sales option offers two economical modes of methane degasification and utilization. This includes multi-zone completed vertical wells and horizontal boreholes, with IRR equal to 25.3 and 11.1%, respectively. The pipeline option provides economical means of utilizing methane because gas enrichment is not required, thus reducing net capital costs. In addition, a relatively high rate in well-head sales prices can be received in this region. Mine 2, producing 2.2 MMtpy coal, is the second longwall mine examined in the Black Warrior basin. It operates in the Mary Lee coalbed at a depth of about 610 m. The current methane control strategy at this mine consists of gob wells and horizontal boreholes with no methane utilization system in-place. Compared to Mine 1, this mine emits about 15 times more methane from ventilation and existing degasification systems. The economic analysis of the gas turbine option suggests that all degasification systems, with the exception of the gas injection system, offer better economic performance when the recovered gas is utilized. The existing base case technology performs the best, with NPV equal to 30.31 million dollars, and IRR equal to 38.1%. The base case technology produces 32 MW of power, of which, 115 million kWh is used to meet on-site mine power requirements, and 120 million kWh excess power is sold off-site. Following this system, multi-zone completed conventional vertical wells offer the next best economic performance. The IRR for this project is lower at 31.2%. The remaining technologies offer IRR between 13.3 and 16.7%. With the pipeline option, the same top performing degasification technologies offer the best economic performance, with the base case leading at IRR equal to 75.6%.

3.2. Central Appalachian basin

Two mines are examined for the Central Appalachian basin area. Of these, Mine 3 is a room and pillar operation, while Mine 4 produces coal using the longwall mining technique. The economic data show that, with either utilization option, no degasification system is economically attractive at Mine 3. Specifically, the NPV ranges between −US$ 1.77 and − 43.10 million for the gas turbine option, and −US$ 2.94 and − 45.97 million for the pipeline sales option. The poor economic performance is primarily due to the low volume of gas captured, as well as high construction costs of gas pipelines.

Similar to Mine 2 in the Warrior basin, Mine 4 in the central Appalachian basin is large and gassy, which increases the number of economic options open to it. With gas turbines, the base case technology offers the highest IRR and NPV (32.9% and US$ 23.52 million, respectively). This operation produces power that meets all of the mine's on-site electricity requirements, in addition to 139 million kWh in excess power. Following closely, multi-zone vertical wells perform the next best. This system requires a capital outlay of US$ 19 million, and produces an IRR equal to 28.3%. All remaining systems, with the exception of the gas injection process, offer IRR ranging between 15.4 and 17.1%. With the pipeline sales option, the same degasification technologies offer better economic performance, with the existing base case technology leading the group. The NPV for the base case system is US$ 25.22 million, and IRR is over 70%. The primary reason for the good performance at this mine site is the large volume of high quality gas recovered from the Pocahontas no. 3 coal seam.

3.3. Northern Appalachian basin

Three model mines represent coal operations in the Northern Appalachian basin (Mines 5, 6, and 7). All degasification systems in this basin are assumed to produce low to medium quality gas which requires processing with the pipeline option. Mine 5 is a small room and pillar operation which does not currently employ methane degasification systems. Similar to the room and pillar mine in the Central Appalachian basin, the results show that all degasification systems perform poorly with gas turbines. The NPV ranges between −US$ 5.09 and − 41.02 million. The economics for the pipeline option are poorer than for the gas turbine option, primarily because all systems require gas cleaning equipment to purify the recovered gas.

Mine 6 employs the longwall mining technique to produce coal from the gassy Pittsburgh coal seam in Greene County, PA. This mine currently uses gob wells to recover and emit about 23 MMcmy methane per year. With the gas turbine option, all degasification technologies, with the exception of those incorporating injection wells, offer equal or better economic performance. Of these, the base case operation, coupled with gas turbines, offer the highest IRR (over 35%). The low heating value gas recovered produces 4.28 MW of power which accommodates about 37 million kWh of the mine's annual continuous electricity demand. No excess power is produced, thus revenue from off-site sale is not recognized. With the pipeline option, only one degasification system (horizontal boreholes) offers better economic performance than the base case degasification technology. The NPV is about US$ 980,000 and the IRR is 15.6%, despite having to purify medium heating value gas recovered from boreholes. The existing degasification system is not a good performer with the pipeline option due to the high enrichment costs incurred from purifying low heating value gob gas. The return for the remaining technologies is low for the same reason.

Mine 7 is also a longwall operation producing 2.7 MMtpy coal from the Pittsburgh coalbed of Monongalia County, WV. Due to the gassiness of the mined seam, Mine 7 employs gob wells with horizontal boreholes to remove methane prior to and during coal mining. The results suggest that the existing degasification system is the best performing option when gas turbines are utilized. The IRR for this operation is over 17%, and meets all of the mine's continuous power demand and about 4 million kWh of annual operating demand. In addition, about 6 million kWh of excess power is sold off-site. Following the base case degasification technology, multi-zone completed wells offer the next highest return (11.8%). However, this system requires over US$ 50 million in capital equipment. All remaining technologies perform poorly with gas turbines, primarily due to the large capital outlays required (US$ 40–81 million). The economics for the pipeline option are less encouraging due to high gas enrichment costs. The base case system offers the least loss with NPV equal to −US$ 1.55 million, with the gas purification systems requiring about US$ 2 million in capital equipment and US$ 610,000 in annual operating costs.

3.4. Illinois basin

The single longwall mine examined in the Illinois basin produces 2.7 MMtpy coal from the Herrin no. 6 coal seam. The base case degasification system at Mine 8 is gob wells, which recover and emit 10.3 MMcmy methane. With the gas turbine option, all technologies with the exception of cross-measure boreholes perform poorly; although the economics for the borehole system are marginal with IRR almost equal to the discount rate of return. Since the implementation of cross-measure boreholes requires modifications in mining configuration, it is not expected to be a viable option. The existing technology, gob wells, offers a negative NPV (−US$ 1.78 million), primarily due to the low volume of gas recovered. The pipeline option does not improve the economic picture at this mine due to this low volume of gas recovered and costs for constructing commercial pipelines.

3.5. Western region

Longwall mines operating in the western US are represented by Mine 9. This mine produces 1.4 MMtpy coal from the Maxwell coal seam of Las Animas County, CO. The current methane control strategy is gob wells with horizontal boreholes, which recover and emit about 26 MMcmy methane without utilization. Of all the technologies examined, the base case system provides positive economic incentives to generate power with gas turbines, with IRR equal to 16.0%. The power generated meets all of the mine's continuous demand, 44% of the operating demand,

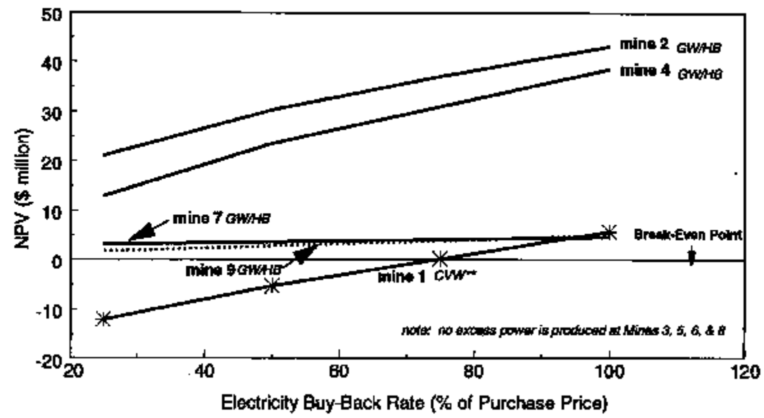

Fig. 1. NPV vs. excess power buy-back rates.

and 14 million kWh in excess power is produced and sold off-site. With the pipeline option, all technologies evaluated perform poorly, primarily due to the construction costs for 37 km of pipeline. If Mine 9 is able to avoid these costs, possibly through collaboration with a gas distribution company, the results would improve dramatically. The IRR increases from 5.7 to 87.0% for multi-zone wells, and from a negative return to 22.9% for the existing degasification system.

3.6. *Sensitivity analysis*

Variations in the engineering and other assumptions made in the study have the potential to significantly change the economic results. Thus, a sensitivity analysis was conducted to evaluate how changes in key design specifications impact the conclusions reached earlier. Primary variables examined include electricity buy-back rate for the turbine option, gas recovery rates, gas quality assumptions, and gas sales price.

3.6.1. *Electricity buy-back rate*

In the initial analyses, the electricity buy-back rate for the degasification options which produced excess power was assigned to be 50% of the electricity purchase price. As shown in Fig. 1, the economics can vary significantly if the buy-back rate is lower or higher than the assumed value. For example, in the Black Warrior basin, multi-zone wells at Mine 1 offered the least loss in profit with gas turbines. To improve the economic performance of this technology, the excess power generated must be sold at a buy-back rate equal to 75% of the electricity purchase price. At Mine 2, the base case degasification system offered a 38% return on investment, and NPV equal to about US$ 30 million. However, if Mine 2 is unable to sell the excess power generated, the IRR drops to 20.5% or US$ 12 million in the NPV. Under this scenario, the savings achieved from using the power on-site still make this system a viable option, although the return is not as high. Fig. 1 illustrates the NPV achieved with varying buy-back rates for the leading economical technologies which produce excess power.

3.6.2. *Gas recovery rates*

Fig. 2 illustrates the economics achieved with varying gas recovery rates. In general, the economics for the gassy mines in the Warrior and central Appalachian basins (Mines 2 and

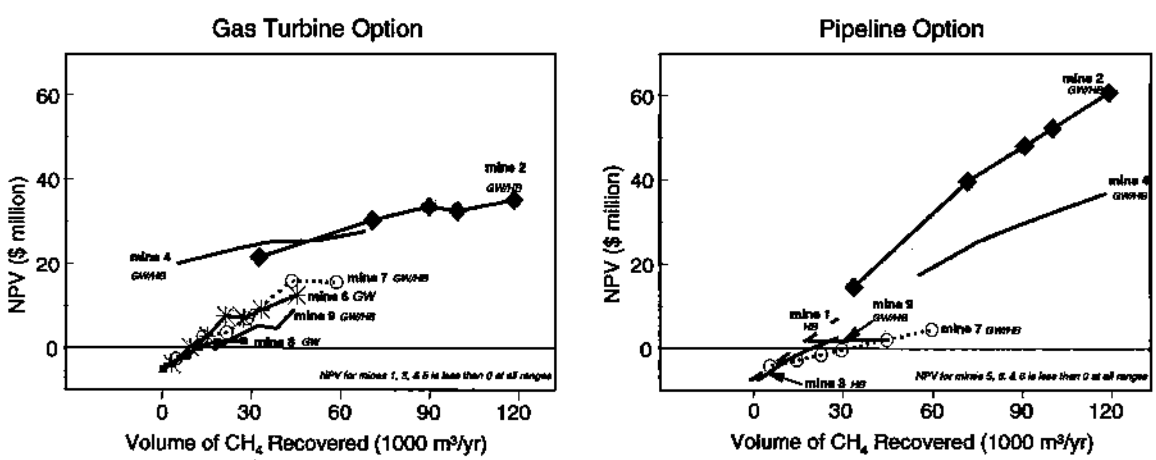

Fig. 2. NPV vs. changes in gas flow rates.

4) are encouraging with both utilization options. Specifically, the pipeline option offers higher returns than gas turbines at increases in gas flow rates. This is because the capital costs for gas turbines become more significant at higher gas volumes, while the costs for the pipeline option remain relatively unchanged other than annual operating cost increases. Fig. 2 also suggests that the economics for Mines 6, 7, 8, and 9 are greater than the baseline (i.e. NPV = 0) provided the gas recovery rate is $>19.8 \times 10^3\,m^3$ methane per year when the turbine option is utilized. The break-even point with the pipeline option is the same for the two mines producing high heating value gas (Mines 1 and 3). For Mines 6 and 7, which require purification systems, higher gas recovery volumes (about $30 \times 10^3\,m^3$ per year) are needed to break even.

3.6.3. Gas quality assumptions

Pre-mining degasification technologies were assumed to produce high heating value gas in the Black Warrior basin. For Mine 1, if the conventional wells are unable to produce pipeline quality gas and enrichment equipment is required, the IRR drops from 25.3 to 9.0% with the pipeline option. This significant drop in return is due to the high purification costs consisting of US$ 3.5 million in capital investment and US$ 1 million in annual operating costs. These results suggest that pipeline quality gas must be recovered to make conventional wells an economical option. Similarly, if gas enrichment costs are accounted for in the base case economic evaluation of Mine 2, the IRR drops from 75.6 to 29.5% due to US$ 5.5 million in capital and US$ 1.9 million in annual operating costs. This analysis shows that inclusion of gas purification costs is necessary to properly represent the economics of degasification systems.

Similar to the Warrior basin mine, pre-mining degasification technologies in the central Appalachian basin produce high heating value gas. If pipeline quality gas is not produced with the base case technology at Mine 5, the IRR drops from 72.2 to 12.9%, and the NPV decreases from US$ 25.22 to 1.98 million. This presents a significantly different economic outlook and shows that such costs must be recognized. For multi-zone conventional wells, about US$ 6.4 million in capital equipment and US$ 2.1 million in annual operating costs reduces the IRR from 47.6 to 16.3%, and the NPV drops from US$ 29.09 to 7.29 million.

All degasification systems in the northern Appalachian basin are assumed to require gas purification systems. For Mine 5, the elimination of gas enrichment equipment does not improve the economics. For Mine 6, if it is assumed that high heating value gas can be recovered as experienced in adjacent coal basins, multi-zone conventional wells is the only option which provides positive economics (IRR equals 15.1% and NPV equals US$ 4.67 million). However, this system still requires over US$ 45 million in capital outlay. The economics for the existing degasification technology improves dramatically if high heating value gob gas is recovered from both gob wells and horizontal boreholes (IRR equals 52.6%). However, it is unlikely that all gas recovered will be of pipeline quality, and some level of gas processing may be required. If it is assumed that about 55% of the recovered gas (12.5 MMcmy) is pipeline quality, the IRR drops to 12.41%. This scenario may be achievable if the mine is able to discontinue the utilization of gob gas when high levels of impurities occur.

In the Illinois basin, it is expected that some portion of the recovered gas will need processing with the combination technology of gob wells with horizontal boreholes. If it is assumed that about 50% of the total recovered gas (11.5 MMcmy) is of pipeline quality and does not require purification, the IRR increases from 0.9 to 14.6%, and the NPV is US$ 410,000. If multi-zone wells produce pipeline quality gas, thus eliminating gas purification costs, the IRR increases from 0.9 to 19.1%.

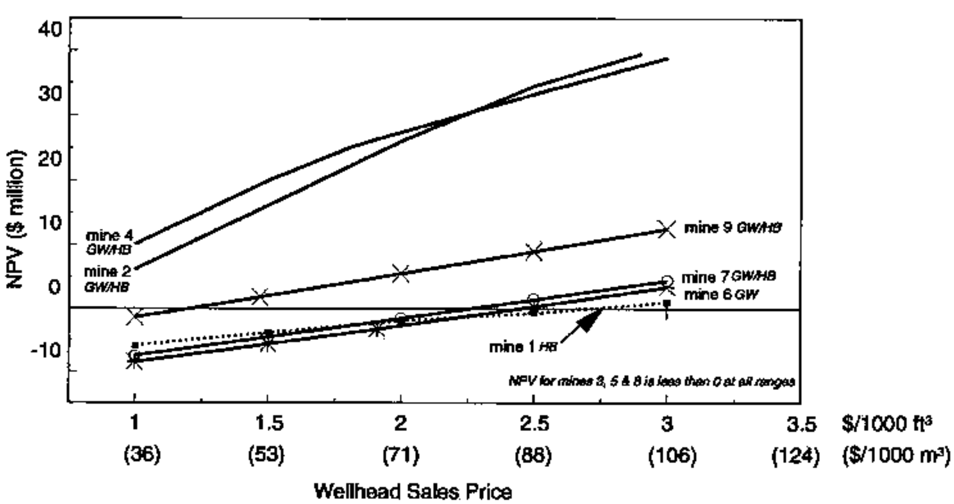

Fig. 3. NPV vs. well-head sales price.

3.6.4. Gas sales price

Fig. 3 illustrates the economics with varying wellhead sales prices. In general, the gassy mines in the northern Appalachian basin (Mines 6 and 7) require a sales price >US$ 88 $\times 10^{-3}\,m^3$ gas to exceed base-line economics, unless pipeline quality gas is produced. Based on current trends in natural gas prices, over US$ 124 $\times 10^{-3}\,m^3$ may be received, making the pipeline option more attractive in this region. The economics for the remaining mines do not improve significantly unless more than US$ 106 $\times 10^{-3}\,m^3$ gas is received, which is achievable with the current trends in rising natural gas prices.

3.6.5. Coal production increases due to decrease in methane emissions

For the several mines which are identified with no economical modes of methane degasification and utilization, it is assumed that the use of degasification technologies provide fewer safety-related shutdowns by reducing the total volume of methane liberated in working areas. As a result of this increased safety, the mine may experience a net increase in coal production if methane emissions are the only limiting factor in coal production. With this assumption, only a 1% increase (10,886 tpy) in coal production is required at Mine 1 to offset the cost of installing horizontal boreholes. At Mine 5, horizontal boreholes would require a 4.5% increase in annual coal production (40,824 tpy), and conventional wells would require a 12.2% increase (110,678 tpy) to obtain a revenue which provides break-even economics.

4. Conclusions

4.1. Region specific trends

- In general, this national assessment suggests that investments in degasification and utilization systems yield higher returns in the Warrior and central Appalachian regions than in any other region examined. This is in agreement with the current practices employed in these areas. The pipeline option provides the highest return due to the large volumes of high heating value gas available from the Mary Lee and Pocahontas no. 3 coalbeds.
- In general, the most economical degasification option for the mines currently employing methane control technology is to employ its existing system. These systems combined with gas turbines or pipelines can offer higher returns, primarily because the mine has already expended significant capital in its existing degasification operation.
- The least gassy room and pillar mines are unable to economically employ degasification and utilization systems to reduce methane emissions. However, a 1–12% increase in coal production rate can offset the cost of implementing these systems.
- Gas turbines seem to be more economical at the gassy mines in the northern Appalachian basin. The pipeline sales option does not perform well because all degasification systems are assumed to require gas enrichment before connecting to national transmission lines. This significantly increases the capital expenditure and operating costs.
- Utilization of gas recovered from the existing methane control system in the Illinois basin 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 uneconomical in this region due to high pipeline construction costs.

4.2. Technology specific trends

- The analysis suggests that the utilization of gas recovered from existing base case technologies offers higher returns, usually with 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 offers better economic performance than the pipeline sales option, provided 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.
- Multi-zone 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 multiple coal seams. However, this technology usually requires significant capital outlay and longer investment periods.
- The developmental gas injection process is burdened with high capital and operating costs from on-site generation, compression, and separation of nitrogen, and provides a return-on-investment that is lower than that which can be achieved with other well utilized technologies.

4.3. Other issues

There are barriers to coalbed methane development related 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. Many coal companies are forced to place the highest emphasis on coal production which limits resources available for coalbed methane recovery investments. Given the uncertainty in the stability of future coal markets natural gas sale prices, companies may be reluctant to invest in coalbed methane recovery projects, especially when the economics can vary significantly with slight variations in key assumptions. During the early 1990s, "Section 29" tax credit enabled several coal companies to economically utilize mine gas. However, such a tax credit is no longer available, and if a similar credit were re-introduced, mine operators would have a strong incentive to utilize the recovered gas. Additional incentives that could boost coal companies' participation in utilizing mine gas include a possible interest shown by the electric power industry to participate in greenhouse gas offset credits. Finally, the deregulations in the electric utilities sector could heighten the interest shown by power producers to offer coal mine gas produced "green energy" to consumers.

These factors not withstanding, should a policy maker wish to know if coalbed methane recovery is prudent or if a mine owner wished to know if it were profitable, this paper should supply the necessary analytical tools to make those decisions. We believe that we have included a sufficient range of mining techniques, geologic variables, and gas recovery systems that one or more of the cases should prove comparable to future mining efforts both in the US and at many locations abroad.

References

American Geophysical Union, 1999. Climate Change and Greenhouse Gases. Eos, vol. 80, no. 5, pp. 49.

Baker, E.C., Grau, R.H., Finfinger, G.L., 1986. Economic Evaluation of Horizontal Borehole Drilling for Methane Drainage from Coalbeds. Information Circular, IC-9080. US Department of the Interior, Bureau of Mines, Pittsburgh, PA.

Baker, E.C., Garcia, F., Cervik, J., 1988. Cost Comparison of Gob Hole and Cross-Measure Borehole Systems to Control Methane in Gobs. Report of Investigations, RI-9151. US Department of the Interior, Bureau of Mines, Pittsburgh, PA.

Campoli, A., Cervik, J., Schatzel, S., 1983. Control of Longwall Gob Gas with Cross-Measure Boreholes (Upper Kittanning coalbed). Report of Investigations, RI-8841. US Department of the Interior, Bureau of Mines, Pittsburgh, PA.

Carter, R.A., 1990. Underground Developments in Methane Recovery. Coal, December.

Cicerone, R.J., 2000. Human forcing of climate change: easing up on the gas pedal. Proc. Natl. Acad. Sci. 97 (19), 10304–10306.

Diamond, W., 1995. Methane Control for Underground Coal Mines. Information Circular, IC-9395. Department of the Interior, Bureau of Mines, Pittsburgh, PA.

Dixon, C.A., 1987. Coalbed methane: a miner's viewpoint. In: Proceedings of the 1987 Coalbed Methane Symposium. Tuscaloosa, AL, pp. 7–10.

Ely, K., Bethard, R., 1989. Controlling underground coal mine methane gas safety hazards through horizontal and vertical degasification operations. In: Proceedings of the 1989 Coalbed Methane Symposium. Tuscaloosa, AL, 17–20 April.

Gabello, D.P., Felts, L.L., Hayoz, F.P., 1981. Methane Drainage with Horizontal Boreholes in Advance of Longwall Mining. US Department of Energy. Morgantown Energy Technology Center, Morgantown, WV.

Garcia, F., Cervik, J., 1985. Methane Control on Longwalls with Cross-Measure Boreholes (Lower Kittanning coalbed). Report of Investigations, RI-8985. Department of the Interior, Bureau of Mines, Pittsburgh, PA.

Hansen, J., Makiko, S., Ruedy, R., Lacis, A., Oinas, V., 2000. Global warming in the 21st century: an alternative scenario. Proc. Natl. Acad. Sci. 97 (18), 9875–9880.

Hayhoe, K., Jain, A., Pitcher, H., MacCracken, C., Gibbs, M., Wuebbles, D., Harvey, R., Kruger, D., 1999. Costs of multigreenhouse gas reduction targets for the USA. Science 286, 905–906.

Hobbs, G.W., Winker, R.O., 1990. Economics and financing of coalbed methane ventures. In: Proceedings of the Eastern Coalbed Methane Forum. Tuscaloosa, AL.

Hogan, K.B., Hoffman, J.S., Thompson, A.M., 1991. Methane on the greenhouse agenda. Nature 354, 181–182.

Intergovernmental Panel on Climate Change (IPCC), 1996. In: Watson, R.T., Zinyowera, M.C., Moss, R.H., Dokken, D.J. (Eds.), Climate Change 1995, Impacts, Adaptations, and Mitigation of Climate Change: Scientific–Technical Analysis, Contribution of Working Group II to the Second Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, UK, 572 pp.

Kravits, S., Sainato, S., Finfinger, G., 1985. Comparison of rotary and in-hole motor technique for drilling horizontal boreholes in coal. Department of the Interior, Bureau of Mines, Pittsburgh, PA. Report of Investigations, RI-8933.

Law, K.S., Nisbet, E.G., 1996. Sensitivity of the CH_4 growth rate to changes in CH_4 emissions from natural gas and coal. J. Geophys. Res. 101 (D9), 14387–14397.

Malinchak, R., Sturgill, C., 1987. Methane Utilization from Coalbeds for Power Generation at Bethlehem Mines Corporation Marianna Mine No. 58. Prepared by Westinghouse Electric Corporation for US DOE, Pittsburgh, PA.

Mills, R.A., Stevenson, J.W., 1991. History of methane drainage at Jim Walter Resources Inc. In: Proceedings of the 1991 Coalbed Methane Symposium. Tuscaloosa, AL, pp. 143–151.

US Department of Energy, 1996. 1994 Underground Coal Mine Gas Emissions Data. US Department of Energy, Pittsburgh Research Center, August 1996.

US Environmental Protection Agency, 1993. Opportunities to reduce anthropogenic methane emissions in the United States, report to congress. In: Hogan, Kathleen, B. (Ed.). EPA-430/R-93-012, US Environmental Protection Agency. Office of Air and Radiation, Washington, DC, 379 pp.

David Kirchgessner has been a senior research scientist in the US Environmental Protection Agency's Office of Research and Development for 25 years and is currently working on methane and mercury emissions from the fossil fuel production industries. He received his PhD in geology as well as a Masters degree in public health administration from the University of North Carolina at Chapel Hill. He received an MA in geology and a BA in economics from the State University of New York at Buffalo.

Sushma Masemore is a chemical engineer with Southern Research Institute, and is a deputy director of the Greenhouse Gas Technology Center, a public–private partnership between the US EPA and SRI. Ms. Masemore has over 12 years experience in air pollution research and engineering, and is currently evaluating innovative distributed generation technologies, including microturbine, fuel cell, and IC engine based CHP systems.

Stephen Piccot is an environmental engineer with over 21 years experience in the field of air pollution research and regulation. He manages the Environmental Studies Department of Southern Research Institute, and is director of the Greenhouse Gas Technology Center; a third-party performance verifier of technologies which mitigate or monitor GHG emissions.