Identifying Opportunities for Methane Recovery at U.S. Coal Mines:

Profiles of Selected Gassy Underground Coal Mines 2002-2006

U.S. Environmental Protection Agency
September 2008 (Revised January 2009)
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U.S. ENVIRONMENTAL PROTECTION AGENCY

* In the previously released version of this report, there was an error on page 1-7 involving two bulleted items dated July 2007. These bullets refer to roof fall events at CONSOL Energy's Bailey (PA) and Buchanan (VA) mines. Both bullets actually refer to the same roof fall event, which occurred at Buchanan mine. Bailey mine was not shut down as previously stated; it produced 10.2 million tons of coal in 2006 and 9.9 million tons in 2007. USEPA regrets the error.

ACKNOWLEDGMENTS

The U.S. EPA would like to thank the U.S. Mine Safety and Health Administration for the ventilation emissions data used in this document. Other industry experts, as well as various individuals at state and federal agencies, were also helpful during the preparation of this document.

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Frequently Used Terms

Coalbed methane (CBM): Methane that resides within coal seams.

Coal mine methane (CMM): As coal mining proceeds, methane contained in the coal and surrounding strata may be released. This methane is referred to as coal mine methane since its liberation resulted from mining activity. In some instances, methane that continues to be released from the coal bearing strata once a mine is closed and sealed may also be referred to as coal mine methane because the liberated methane is associated with past coal mining activity.

Degasification system: A system that facilitates the removal of methane gas from a mine by ventilation and/or by drainage. However, the term is most commonly used to refer to removal of methane by drainage technology.

Drainage system: A system that drains methane from coal seams and/or surrounding rock strata. These systems include vertical pre-mine wells, gob wells, and in-mine boreholes.

Methane drained: The amount of methane removed via a drainage system.

Methane emissions: This is the total amount of methane that is not used and therefore emitted to the atmosphere. Methane emissions are calculated by subtracting the amount of methane used from the amount of methane liberated (emissions = liberated – used).

Methane liberated: The total amount of methane that is released, or liberated, from the coal and surrounding rock strata during the mining process. This total is determined by summing the volume of methane emitted from the ventilation system and the volume of methane that is drained.

Methane recovered: The amount of methane that is captured through methane drainage systems.

Methane used: The amount of captured methane put to productive use (e.g., natural gas pipeline injection, fuel for power generation, etc.).

Ventilation system: A system that is used to control the concentration of methane within mine working areas. Ventilation systems consist of powerful fans that move large volumes of air through the mine workings to dilute methane concentrations.

Frequently Used Abbreviations

b (or B)	Billion (10^9)
Bcf	Billion cubic feet
Btu	British Thermal Unit
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
CBM	Coal Bed Methane
cf	Cubic Feet
CH_4	Methane
CO_2	Carbon Dioxide
CMM	Coal Mine Methane
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FOB	Freight on Board
GWh	Gigawatt-hour
GWP	Global Warming Potential
IC	Internal Combustion
kWh	Kilowatt-hour
m (or M)	Thousand (10^3)
mm (or MM)	Million (10^6)
$MMTCO_2e$	Million metric tonnes CO_2 equivalent
MSHA	Mine Safety and Health Administration
MW	Megawatt
NA	Not Available (as opposed to Not Applicable)
PUC	Public Utility Commission

t (or T)	ton (short tons are used throughout this report)
USEPA	U.S. Environmental Protection Agency
USBM	U.S. Bureau of Mines
UMWA	United Mine Workers of America
VAM	Ventilation Air Methane

1. Executive Summary

1. Executive Summary

The purpose of this report is to provide information about specific opportunities to develop methane recovery and use projects at large underground coal mines in the United States. This report contains profiles of 50 U.S. coal mines that may be potential candidates for methane recovery and use, and details about on-going recovery and use projects at 14 of the mines. The United States Environmental Protection Agency (EPA) designed the profiles to help project developers perform an initial screening of potential projects. While the mines profiled in this report appear to be good candidates, a detailed evaluation would need to be done on a site-specific basis in order to determine whether the development of a specific methane recovery and use project is both technically and economically feasible.

Since the last version of this report was published in September 2005, coal mine methane (CMM) recovery and use in the U.S. has continued to develop and grow from an estimated 42 billion cubic feet (Bcf) in 2003 to over 46 Bcf in 2006. At a gas price of $6.40 per thousand cubic feet (mcf)[1], this means that coal mine methane developers had estimated revenues of more than $295 million in 2006.

Methane Emissions and Recovery Opportunities

Non-CO_2 gases play important roles in efforts to understand and address global climate change. The non-CO_2 gases include a broad category of greenhouse gases (GHG) other than carbon dioxide (CO_2), such as methane (CH_4), nitrous oxide (N_2O), and a number of high global warming potential (GWP) gases. The non-CO_2 gases are more potent than CO_2 (per unit weight) and are significant contributors to global warming. Thus, reducing emissions of non-CO_2 gases can help prevent global climate change and produce broader economic and environmental benefits.

Methane is a greenhouse gas that exists in the atmosphere for approximately 9-15 years. As a greenhouse gas, CH_4 is over 20 times more effective in trapping heat in the atmosphere than carbon dioxide – over a 100-year period – and is emitted from a variety of natural and human-influenced sources. Human-influenced sources include landfills, natural gas and petroleum systems, agricultural activities, coal mining, stationary and mobile combustion, wastewater treatment, and certain industrial processes.

As a primary constituent of natural gas, methane is also an important, relatively clean-burning energy source. As a result, efforts to prevent or utilize methane emissions can provide significant energy, economic, and environmental benefits. In the United States, many companies are working with EPA in voluntary efforts to reduce emissions by implementing cost-effective management methods and technologies.

U.S. EPA

U.S. industries, along with state and local governments, collaborate with the U.S. Environmental Protection Agency to implement several voluntary programs that promote profitable opportunities for reducing emissions of methane, an important greenhouse gas. These programs are designed to overcome a wide range of informational, technical, and institutional barriers to reducing methane emissions, while creating profitable activities for the coal, natural gas, petroleum, landfill, and agricultural industries.

[1] Average wellhead price for 2006 according to EIA < http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm >.

To realize continued emission reductions from the coal mining industry, EPA's Coalbed Methane Outreach Program (CMOP) has worked voluntarily with the coal mining industry and associated industries since 1994 to recover and use methane released into and emitted from mines.

CMOP's efforts are directed to assist the mining industry by supporting project development, overcoming institutional, technical, regulatory and financial barriers to implementation, and educating the general public on the benefits of CMM recovery. More specifically, these efforts include:

- Identifying, evaluating, and promoting methane reduction options including technological innovations and market mechanisms to encourage project implementation;
- Workshops to educate the coal mine methane project development community on the environmental, mine safety, and economic benefits of methane recovery;
- Preparing and disseminating reports and other materials that address topics ranging from technical and economic analyses to overviews of legal issues;
- Interfacing with all facets of the industry to advance real project development;
- Conducting pre-feasibility and feasibility studies for U.S. mines that examine a range of end-use options; and
- Managing a website that is an important information resource for the coal mine methane industry.

Coal Mine Methane (CMM) Recovery Opportunities

In the U.S., coal mines account for over 10% of all man-made methane emissions (USEPA, 2008). Today, there are methane recovery and use projects at mines in Alabama, Colorado, Pennsylvania, Virginia, and West Virginia. As shown in this report, there are many additional gassy coal mines at which projects have not yet been developed that offer the potential for the profitable recovery of methane.

In addition to the direct financial benefits that may be enjoyed from the sale of coal mine methane (CMM), indirect financial and economic benefits may also be achieved. Degasification systems that are used to drain methane prevent gas from escaping into mine working areas, increase methane recovery, improve worker safety, and significantly reduce ventilation costs at several mines. Increased recovery also reduces methane-related mining delays, resulting in increased coal productivity. Furthermore, the development of methane recovery projects has been shown to result in the creation of new jobs, which has helped to stimulate area economies.[2] Additionally, the development of local coal mine methane resources may result in the availability of a potentially low-cost supply of gas that could be used to help attract new industry to a region. For these reasons, encouraging the development of coal mine methane recovery projects is likely to be of growing interest to state and local governments that have candidate mines in their jurisdictions.

For example, some of the mines profiled in this report have methane emissions in excess of ten million cubic feet per day (cf/d) (or nearly 3.7 billion cubic feet per year). To illustrate the impact of methane recovery, developing a project at a mine recovering two billion cubic feet per year would result in emissions reductions equating to 890,000 tons of CO_2.[3] Because of the large environmental benefits that may be achieved, coal mine methane projects may serve as cost-effective alternatives for utilities and others seeking to offset their own greenhouse gas emissions. Additionally, even though the U.S. has not ratified the Kyoto Protocol, voluntary GHG emissions reduction programs such as the Chicago

[2] For example, see discussion on this subject in the report "The Environmental and Economic Benefits of Coalbed Methane Development in the Appalachian Region" (USEPA, 1994).

[3] The carbon dioxide equivalent of methane emissions is calculated by determining the weight of methane collected (on a 100% basis), using a density of 19.2 g/cf. The weight is then multiplied by the global warming potential (GWP) of methane, which is 21 times greater than carbon dioxide over a 100 year time period.

Climate Exchange (CCX) and The Climate Registry allow mining companies to turn their avoided emissions into carbon credits.

Overview of CMM Recovery and Use Techniques

Methane gas and coal are formed together during coalification, a process in which biomass is converted by biological and geological processes into coal. Methane is stored within coal seams and also within the rock strata surrounding the seams. Methane is released when pressure within a coalbed is reduced as a result of natural erosion, faulting, or mining. Deep coal seams tend to have a higher average methane content than shallow coal seams, because the capacity to store methane increases as pressure increases with depth. Accordingly, underground mines release substantially more methane than surface mines, per ton of coal extracted.

Coal mine methane emissions may be mitigated by the implementation of methane recovery projects at underground mines. Mines can use several reliable degasification methods to drain methane. These methods have been developed primarily to supplement mine ventilation systems that were designed to ensure that methane concentrations in underground mines remain within safe concentrations. While these degasification systems are mostly used for safety reasons, they can also recover methane that may be employed as an energy resource. Degasification systems include vertical wells (drilled from the surface into the coal seam months or years in advance of mining), gob wells (drilled from the surface into the coal seam just prior to mining), and in-mine boreholes (drilled from inside the mine into the coal seam or the surrounding strata prior to mining).

The quality (purity) of the gas that is recovered is partially dependent on the degasification method employed, and determines how the gas can be used. For example, only high quality gas (typically greater than 95% methane) can be used for pipeline injection. Vertical wells and horizontal boreholes tend to recover nearly pure methane (over 95% methane). In very gassy mines, gob wells can also recover high-quality methane, especially during the first few months of production. Over time, however, mine air may become mixed with the methane produced by gob wells, resulting in a lower quality gas.

Lower quality methane can also be used as an energy source in various applications. Potential applications that have been demonstrated in the U.S. and other countries include:

- Electricity generation (the electricity can be used either on-site or can be sold to utilities);
- As a fuel for on-site preparation plants or mine vehicles, or for nearby industrial or institutional facilities; and
- Cutting-edge applications, such as in fuel cells.

It is also possible to enrich lower quality gas to pipeline standards using technologies that separate methane from carbon dioxide, oxygen, and/or nitrogen. Several technologies for separating methane are under development. Another option for improving the quality of mine gas is blending, which is the mixing of lower quality gas with higher quality gas whose heating value exceeds pipeline requirements.

Even mine ventilation air methane (VAM), which typically contains less than 1% methane, has been and is being successfully used. At a mine in Australia, VAM was used as combustion air in gas-fired internal combustion engines. The technology for using mine ventilation air as combustion air in turbines and coal-fired boilers also exists. The first commercial-scale technology to oxidize VAM in the world, located in New South Wales, Australia, became operational in September 2007 (USEPA, 2007b). The plant generates approximately 6 megawatts (MW) of electricity and reduces greenhouse gas emissions by more than 275,000 tons of CO_2 equivalent (CO_2e) per year. U.S. EPA and U.S. DOE are conducting a technology demonstration of a thermal flow reversal reactor (same technology used at West Cliff colliery in Australia) to simulate the destruction of VAM at a closed mine in West Virginia.

Opportunities for Methane Recovery Projects

While methane recovery projects already are operating at some of the gassiest mines in the U.S., there are numerous additional gassy mines at which recovery projects could be developed. This report profiles 50 mines that have either already implemented projects, or are potential candidates for the development of coal mine methane projects. As of 2006, at least 23 mines operate drainage systems, with drainage efficiencies in the range of 3% to 88%. Twelve of these mines already sell recovered methane, and two mines consume methane onsite for power generation and to heat mine ventilation air.[4] Mines that already use drainage systems may be especially good candidates for the development of cost-effective methane recovery and use projects.

There are also projects at abandoned mines in the U.S.; however, this report only profiles mines active in 2006.[5] For additional information on methane recovery projects at abandoned coal mine sites, see the EPA report, *U.S. Abandoned Coal Mine Methane Recovery Project Opportunities*, available on the CMOP website at http://www.epa.gov/cmop/docs/cmm_recovery_opps.pdf

Surface mines may also be candidates for recovery and utilization projects. Surface mine opportunities are addressed in the EPA report, *U.S. Surface Coal Mine Methane Recovery Project Opportunities*, which is available on the CMOP website at
http://www.epa.gov/cmop/docs/cmm_recovery_opps_surface.pdf

Overview of Methane Liberation, Drainage, and Use at Profiled Mines

This report profiles mines located in 12 states. West Virginia has the largest number of profiled mines with 13, followed by Alabama with six, and Kentucky, Pennsylvania, and Virginia with five each. In 2006, the 50 mines profiled in this report liberated an estimated 364 mmcf/d of methane, or about 133 Bcf/yr (98% of all methane liberated from underground mines). Table 1-1 summarizes information presented in the state summaries and individual mine profiles (Chapter 6), and shows the number of profiled mines and the estimated total methane liberated from these mines. Chapter 4 explains how these data were derived.

As of 2006, 23 of the profiled mines operate drainage systems. West Virginia has the largest number of mines with drainage systems with seven, followed by Alabama with five, Colorado and Pennsylvania with three each, Utah and Virginia with two each, and New Mexico with one. In 2006, the 23 mines operating drainage systems reported an estimated 168 mmcf/d of methane drained, or about 60 Bcf/yr. These mines have drainage efficiencies ranging from 3% to 88%. Table 9 in Chapter 5 shows mines that employ drainage systems, the type of drainage system used, and estimated drainage efficiency.

Table 1-1 shows that about 35% of the total estimated methane liberated from all profiled mines is being used. Table 1-1 also shows estimated annual methane emissions from the mines that are operating but not using methane and the estimated annual methane emissions that would be avoided by implementing methane recovery and use projects at these mines, assuming a 20-60% range of recovery efficiency (i.e. the portion of total methane liberated that is recovered and utilized). Based on these recovery efficiencies, if methane recovery projects were implemented at profiled mines that are currently operating but do not recover methane, an estimated 9-28 Bcf/yr of additional methane emissions would be avoided. This is equivalent to about 4-12 $MMTCO_2e$. Moreover, there is significant potential for increased methane recovery at many of the mines that already have recovery projects.

[4] Please see Chapter 4 for a more detailed discussion of this issue.
[5] Blue Creek No. 5, Dakota No. 2, Wabash, and VP 8 mines were all active in 2006, but have since been abandoned.

Table 1-1: U.S. Summary Table Number of Profiled Mines and Estimated Methane Liberated and Used in 2006[1]							
	Operating but not Using Methane		Operating and Using Methane		All Mines Profiled in This Report		
State	Number of Mines	Total Methane Liberated (mmcf/d)	Number of Mines	Total Methane Liberated (mmcf/d)	Number of Mines	Total Methane Liberated (mmcf/d)	Estimated Methane Use (mmcf/d)
Alabama	1	4.9	5	76.4	6	81.3	47.5
Colorado	3	10.3	1	18.2	4	28.6	0.5
Illinois	4	13.6	0	0.0	4	13.6	0.0
Indiana	1	3.1	0	0.0	1	3.1	0.0
Kentucky	5	5.3	0	0.0	5	5.3	0.0
New Mexico	1	6.5	0	0.0	1	6.5	0.0
Ohio	2	3.9	0	0.0	2	3.9	0.0
Oklahoma	1	0.9	0	0.0	1	0.9	0.0
Pennsylvania	3	25.9	2	17.5	5	43.4	5.7
Utah	3	12.1	0	0.0	3	12.1	0.0
Virginia	3	5.7	2	91.4	5	97.0	63.9
West Virginia	9	35.3	4	33.4	13	68.7	9.1
TOTAL[2]:	36	127.5	14	236.8	50	364.3	126.7
Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent from Operating Mines not Currently Using Methane (36 mines):						**Methane (Bcf/y)**	**CO_2 (mmt/y)**
2006 Estimated Total Emissions						46.5	20.7
Estimated Annual Avoided Emissions if Recovery Projects are Implemented						9.3 – 27.9	4.1 – 12.4

[1]Chapter 4 explains how these data were estimated.

[2] Values shown here do not always sum to totals due to rounding.

Overview of U.S. Mining Industry Since 2003

Significant changes have occurred in the U.S. mining industry since 2003 when this report was last updated. Total coal production has increased since the 2003 level of 1,071 million short tons, reaching back-to-back record levels in 2005 and 2006. 2006 coal production was 1,162 million short tons, 31 million short tons higher than the previous record set in 2005. Furthermore, 2006 is the third consecutive year with coal production of 1,100 million short tons or more. Much of the increase in coal production is attributable to surface mines, which have seen coal production grow by 12% from 2003 to 2006, while underground coal production has grown by only 2% over the same period. The overall number of mining operations in the U.S. continued to decline in 2006, especially in the Appalachian region where a significant number of smaller mining operations are located. In January 2006, two different incidents at the Sago and Aracoma mines in West Virginia led to new legislation at both the Federal and state level requiring improvement in safety at underground mines.

This report includes profiles of nine mines that did not appear in the previously. Four new gassy mines have opened since 2003:

- McClane Canyon mine (CO)
- Jones Fork E-3 mine (KY)
- E3-1 mine (KY)
- Miles Branch mine (VA)

Five other mines profiled in 2006 for the first time became gassier than before:

- Bowie No. 2 mine (CO)
- Pattiki mine (IL)
- Dotiki mine (KY)
- Century mine (OH)
- No. 2 mine (VA)

Since 2003, CMM recovery and use projects came online at three mines:

- Cumberland mine (PA)
- Emerald mine (PA)
- Loveridge No. 22 mine (WV)

One project suspended methane utilization:

- San Juan South mine (NM)

Nine mines profiled in 2003 are not included in this report:

- One mine has been closed:
    - Baker mine in Kentucky (KY)
- The other eight mines are less gassy in 2006 than they were in 2003:
    - Elkhart mine (IL)
    - Cardinal mine (KY)
    - Clean Energy No. 1 mine (KY)
    - E3RF mine (now No. 10 mine) (KY)
    - Freedom Energy No. 1 mine (KY)
    - Mine #1 (KY)
    - Sentinel mine (WV)
    - Upper Big Branch-South (WV)

Other developments having a significant impact on mining operations and/or production are highlighted below in the year they occurred:

2004

- Loveridge No. 22 (WV) resumed coal production after temporarily being idled in 2003 due to a fire.
- Production at McElroy (WV) increased by 1.6 million short tons after the installation of a second longwall unit.
- Elk Creek mine (CO) production increased by 2 million short tons, helping Colorado coal production to reach record levels.

2005

- A fire at the Buchanan (VA) mine in February 2005 closed the mine for four months. In September the conveyor that transports coal to the surface malfunctioned, impacting mining for an additional four months.
- West Elk (CO) mine was temporarily closed due to high carbon monoxide levels, impacting production in late 2005.
- Blue Creek No. 5 (AL) was idled for a period due to water ingress problems. Production at Blue Creek No. 7 (AL) was reduced as the mine encountered adverse geological conditions. Issues at both mines were resolved in the fourth quarter of 2005.

2006

- Buchanan mine (VA) came back online, contributing to the increase in overall coal production in Virginia by 7.2% over 2005 levels.
- West Elk mine (CO) was idled in the first quarter of 2006 due to a combustion event in October 2005.
- Production at Shoal Creek (AL) declined after a series of methane ignitions and a roof collapse in February.
- Shoemaker mine (WV) was idled in April 2006.
- Blue Creek No. 4 (AL) production declined due to thin seam conditions and weak roof conditions experienced in April 2006. This resulted in a longwall move.

While most of the data found in the mine profiles contained in this report are based on 2006 data (the most recent, complete data set available) some other more-recent developments are worth noting:

- As planned, Blue Creek No. 5 (AL) was abandoned (mining operations ceased in 2006). Depletion of reserves and adverse geological conditions were the reasons for abandonment.
- Blue Creek No. 7 (AL) added a longwall unit and 3 continuous miner sections. Jim Walter Resources (JWR) hopes to increase production by 2.7 million short tons to help replace the lost production from Blue Creek No. 5 (AL). The longwall unit should be operational in early 2009. The prep plant at No. 5 will serve the expansion at No. 7.
- Shoal Creek (AL) resumed operations helping replace some of the lost production in Alabama associated with the shutdown of Blue Creek No. 5 (AL).
- Elk Creek (CO) mine was expanded and production increased by 1.1 million short tons in 2007.
- Wabash mine (IL) was placed on long-term idle status in April 2007, and VP 8 (VA) and Dakota No. 2 (WV) were abandoned in 2007.
- Production at West Ridge (UT) increased by greater than 1 million short tons in 2007.
- Cleveland-Cliffs acquired PinnOak Resources (Oak Grove and Pinnacle mines) in July 2007.
- In July 2007, production at Buchanan mine (VA) was suspended after several roof falls in previously mined areas damaged some of the ventilation controls inside the mine. The mine was reopened in January 2008. As a result, production at the mine was 44% below 2006 levels.
- Also in January 2008, a fire at Eighty-Four mine (PA) closed the mine for 2 weeks.

Summary of Opportunities for Project Development

Most underground coal mines still do not recover and use methane. However, the profiles in this report indicate that many of these mines appear to be strong candidates for cost-effective recovery projects. Furthermore, this report contains information suggesting that substantial environmental, economic, and energy benefits could be achieved if mines that currently emit methane were to recover and use it.

The mines profiled in this report are quite variable in terms of the amount of methane they liberate, their gassiness or "specific emissions" (methane liberated per ton of coal mined), and their annual coal production. The volume of methane liberated from each mine ranges from less than 0.8 mmcf/d to over

70 mmcf/d. Similarly, specific emissions range from 71 cf/ton to approximately 6,695 cf/ton[6]. Annual coal production ranges from approximately 200,000 tons at some mines to over 10 million tons per year at others. These metrics affect each mine's potential as a project opportunity. Furthermore, as shown in the profiles (Chapter 6), the candidate mines vary with respect to other important metrics, such as the distance from the mine to a pipeline or the projected remaining productive life of the mine. Accordingly, the overall feasibility of developing a methane recovery project will likely vary widely among the candidate mines.

Although a number of the mines profiled here show strong potential for profitable projects, methane ventures at these mines face barriers to coal mine methane development, including market incentives and regulatory structures. Gas prices have improved, increasing the economic benefits of coalbed methane recovery. Restructuring of the gas industry has created new market opportunities for coal mine methane, and the potential for distributed generation is increasing as a result of electricity industry restructuring. At the same time, utilities and other industries are seeking opportunities to offset greenhouse gas emissions and to develop "environmentally friendly" projects. While the U.S. has not ratified the Kyoto Protocol, voluntary markets have emerged where carbon credits generated from methane reductions at coal mines can be traded. If projects are initiated at even a few of the mines profiled here, substantial methane emissions reductions and increased profits for developers could be achieved, thereby benefiting the U.S. economy and the global environment.

The following chapters are in this report:

- Chapter 2 provides an introduction to coal mine methane in the U.S., including a discussion of major developments in the coal mine methane recovery industry that have transpired since publication of the previous version of this report in 2005.
- Chapter 3 discusses current coal mine methane recovery and use projects in the U.S.
- Chapter 4 provides a key to evaluating the mine profiles.
- Chapter 5 presents the mine summary tables.
- Chapter 6 lists state summaries and actual mine profiles, which should assist potential investors in assessing the overall potential project profitability.

[6] CONSOL Energy's VP 8 mine in Virginia had specific emissions of 24,295 cf/ton based on total methane liberated in 2006. However, the mine was shut down in spring 2006 but gas recovery continued, leading to elevated methane liberated per ton of coal produced. Based on first quarter coal production – the last full quarter of production – of 0.259 million short tons and quarterly methane liberation of 1,734 mmcf, specific emissions for the last full quarter of operation were 6,695 cf/ton.

2. Introduction

2. Introduction

Purpose of Report

This report provides information about specific opportunities to develop methane recovery and use projects at large underground mines in the United States. The audience for this report consists of those who may be interested in identifying such opportunities, including utilities, natural gas resource developers, independent power producers, and local industries or institutions that could directly use the methane recovered from a nearby mine.

This introduction provides a broad overview of the technical, economic, regulatory, and environmental issues concerning methane recovery from coal mines. The report also presents an overview of existing methane recovery and use projects (Chapter 3). Chapter 4 contains information that will assist the reader in understanding and evaluating the data presented in Chapters 5 and 6. Chapter 5 contains data summary tables, and finally, Chapter 6 profiles individual underground coal mines that appear to be good candidates for the development of methane recovery projects.

Recent Developments in the Coal Mine Methane Industry

Since the last version of this document was published in September 2005, there have been significant developments in coal mine methane recovery, particularly in the number of active recovery and use projects. The number of mines with active methane recovery and use projects has increased from 12 in 2003 to 14 in 2006. As a result, the amount of methane recovered has increased by 10% from 42 Bcf in 2003 to over 46 Bcf in 2006. Assuming an average gas price of $6.40/mcf[7], coal mine methane developers had estimated revenues of more than $295 million in 2006. The resulting decrease in methane emissions has benefited the global environment by reducing greenhouse gas emissions by nearly 21 million tons of CO_2e in 2006. Figure 2-1 shows the number of mines engaging in coal mine methane recovery and use since 1994. Figure 2-2 shows the growth in the gas recovered from these projects.

The growth in recovered methane since 1990 can be attributed to five primary factors:

(1) Continued use in natural gas pipelines
(2) Use for a variety of purposes besides pipeline injection
(3) Legislation concerning ownership issues has been enacted in most coalbed methane producing states
(4) Various projects have proven the profit-generating potential of coal mine methane recovery
(5) Growing awareness of the climate change impacts of methane emissions

Furthermore, the issuance of FERC Orders 636 in 1992 and 888 in 1996 continue to remove barriers to free and open competition in the natural gas and electric utility industries, respectively. As a result of these orders, coal mine methane developers have been encountering fewer problems accessing the available capacity of the nation's gas and electric transmission lines.

[7] Average wellhead price for 2006 according to EIA <http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm>

Figure 2-1: Mines with Active Coal Mine Methane Recovery and Use Projects

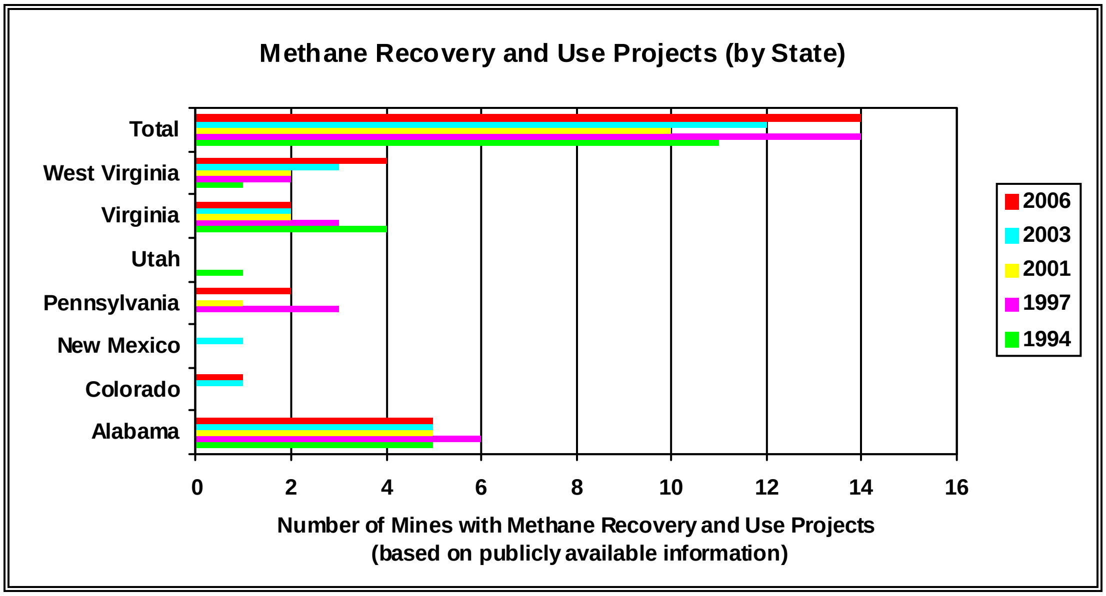
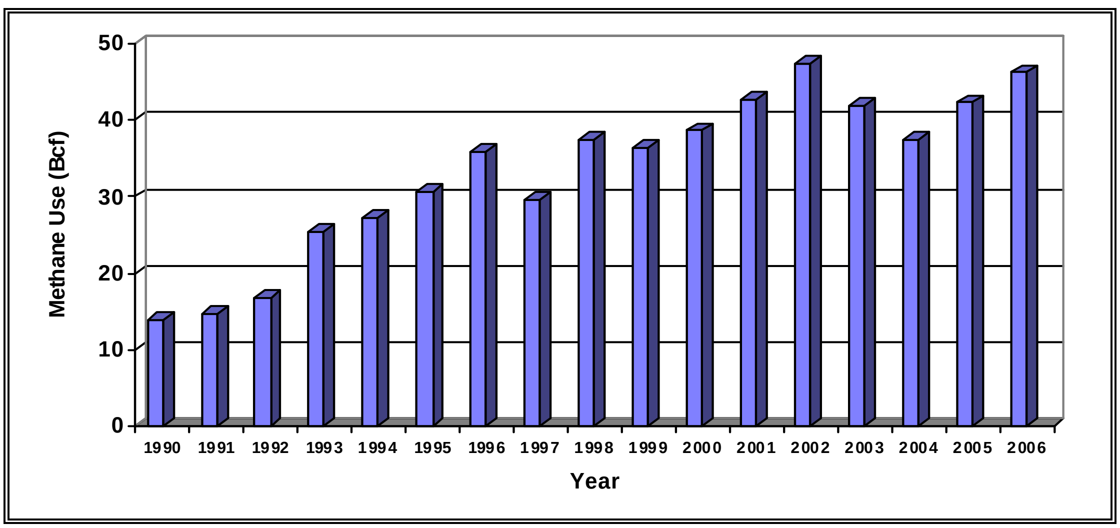


Figure 2-2: Estimated Annual Use of Methane Recovered From U.S. Coal Mines (based on publicly available information)



Overview of Coal Mine Methane

Methane and coal are formed together during coalification, a process in which vegetation is converted by geological and biological forces into coal. Methane is stored in large quantities within coal seams and also within the rock strata surrounding the seams. Two of the most important factors determining the amount of methane that will be stored in a coal seam and the surrounding strata are the rank and the depth of the coal. Coal is ranked by its carbon content; coals of a higher rank have a higher carbon content and generally a higher methane content.[8] The capacity to store methane increases as pressure increases with depth. Thus, within a given coal rank, deep coal seams tend to have a higher methane content than shallow ones.

Methane concentrations typically increase with depth; therefore, underground mines tend to release significantly higher quantities of methane per ton of coal mined than do surface mines. In 2006, while only 31% of U.S. coal was produced in underground mines, these mines accounted for over 60% of estimated methane emissions from coal mining (USEPA, 2008). Among underground mines, the largest and gassiest mines typically have the best potential for profitable recovery and utilization of methane. Although the options for recovering and using methane are primarily available for underground mines, gas recovery at surface mines may also be feasible.

Methane emissions resulting from coal mining activities account for 6% of annual global methane emissions from anthropogenic (man-made) sources. In 2005, China was the largest emitter of coal mine methane, followed by the United States and then Ukraine, Russia, North Korea, and Australia (USEPA, 2006b). In 2006, coal mining emissions were estimated to account for 10.5% of total U.S. methane emissions (USEPA, 2008), down from 11.2% in 1995.

In underground mines, methane poses a serious safety hazard for miners because it is explosive in low concentrations (5 to 15% in air). In the U.S., MSHA requires that methane concentrations in the mine may not exceed 1% in mine working areas and 2% in all other locations. In many underground mines, methane emissions can be controlled solely through the use of a ventilation system, which pumps large quantities of air through the mine in order to dilute the methane to safe levels. The coal mine methane released to the atmosphere by the mine ventilation system is typically below 1%. This methane vented from coal mine exhaust shafts constitutes the largest source of coal mine methane emissions in the U.S. In 2006, for example, 81 Bcf or 60% of the 135 Bcf released from underground mines was released through mine ventilation systems (USEPA, 2008).

In particularly gassy mines, however, the ventilation system must be supplemented with a drainage system. Drainage systems reduce the quantity of methane in the working areas by draining the gas from the coal-bearing strata before, during, or after mining, depending on mining needs. Emissions from drainage systems are estimated to account for approximately 40% of the total methane emissions from underground coal mining. At least 23 of the mines profiled in this report have some type of drainage system.

Methane Drainage Techniques

Over the years, mine operators have realized the economic benefits of employing drainage systems. For mines that have drainage systems in place, the cost of ventilation is significantly reduced because the drainage systems recover a significant percentage of the associated methane. Use of methane drainage systems also help reduce production costs, as there are typically fewer methane-related delays at mines that employ drainage systems (Kim and Mutmansky, 1990). Today, methane drainage is a proven technology and much of the gas that is recovered can be used in various applications.

While drainage systems are currently used primarily for economic and safety reasons to ensure that methane concentrations remain below acceptable levels, these systems recover methane that also can be employed as an energy source. The quantity and quality of the methane recovered will vary

[8] In descending order, the ranks of coal are: graphite, anthracite, bituminous, sub-bituminous, and lignite. Most U.S. production is bituminous or sub-bituminous.

according to the method used. The quality of the recovered methane is measured by its heating value. Pure methane has a heating value of about 1000 British Thermal Units per cubic foot (Btu/cf), while a mixture of 50% methane and 50% air has a heating value of approximately 500 Btu/cf.

Drainage methods include vertical wells (vertical pre-mine), gob wells (vertical gob), longhole horizontal boreholes, and horizontal and cross-measure boreholes. The preferred recovery method will depend, in part, on mining methods and on how the methane will be used. In some cases, an integrated approach using a combination of the above drainage methods will lead to the highest recovery of methane. The key features of the methane recovery methods are discussed in more detail below and are summarized in Table 2-1.

Vertical Pre-Mining Wells

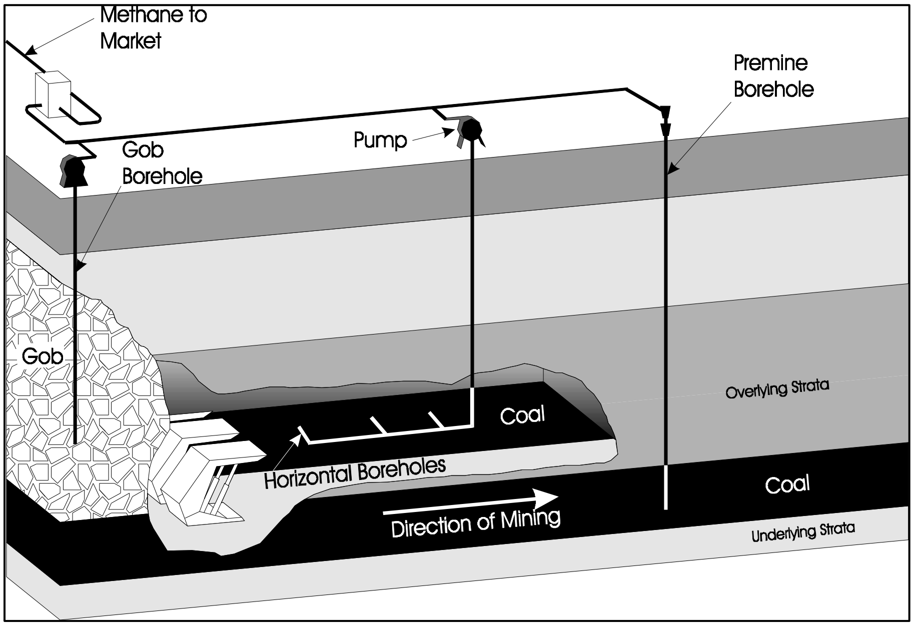
Vertical pre-mining wells are the optimal method for recovering high quality gas from the coal seam and the surrounding strata before mining operations begin. Pre-mine drainage ensures that the recovered methane will not be contaminated with ventilation air from mine working areas. Similar in design to conventional oil and gas wells, vertical wells can be drilled into the coal seam several years in advance of mining. Vertical wells, which may require hydraulic or nitrogen fracturing of the coal seam to activate the flow of methane, typically produce gas of over 90% purity. However, these wells may produce large quantities of water and small volumes of methane during the first several months they are in operation. As this water is removed and the pressure in the coal seam is lowered, methane production increases.

The total amount of methane recovered using vertical pre-drainage will depend on site-specific conditions and on the number of years the wells are drilled prior to the start of mining. Recovery of from 50 to over 70% of the methane that would otherwise be emitted during mining operations is likely for operations in which vertical degasification wells are drilled more than 10 years in advance of mining. Although not previously used widely in the coal mining industry, vertical wells are increasing in popularity within the coal industry, and are used by numerous stand-alone operations[9] that produce methane from coal seams for sale to natural gas pipelines. In some very low permeability coal seams, vertical wells may not be a cost-effective technology due to limited methane flow. Vertical wells, however, will likely continue to be a viable recovery technology for most underground mines.

Six of the underground U.S. coal mines currently employing methane drainage systems use vertical pre-mining wells. A majority of these mines already recover methane for pipeline sales (see section on existing methane recovery and use projects). Figure 2-3 illustrates a vertical pre-mine well.

[9] The term "stand-alone" refers to coalbed methane operations that recover methane for its own economic value. In most cases, these operations recover methane from deep and gassy coal seams that are not likely to be mined in the near future.

Figure 2-3: Vertical Pre-Mining Gob, and Horizontal Boreholes



Gob Wells

Gob wells are drilled from the surface to a point 10 to 50 feet above the target seam prior to mining. As mining advances under the well, the methane-charged strata surrounding the well fracture. Relaxation and collapse of strata surrounding the coal seam creates a fractured zone known as the "gob" area, which is a significant source of methane. Methane emitted from the gob flows into the gob well and up to the surface. A vacuum is frequently used on the gob wells to prevent methane from entering mine working areas.

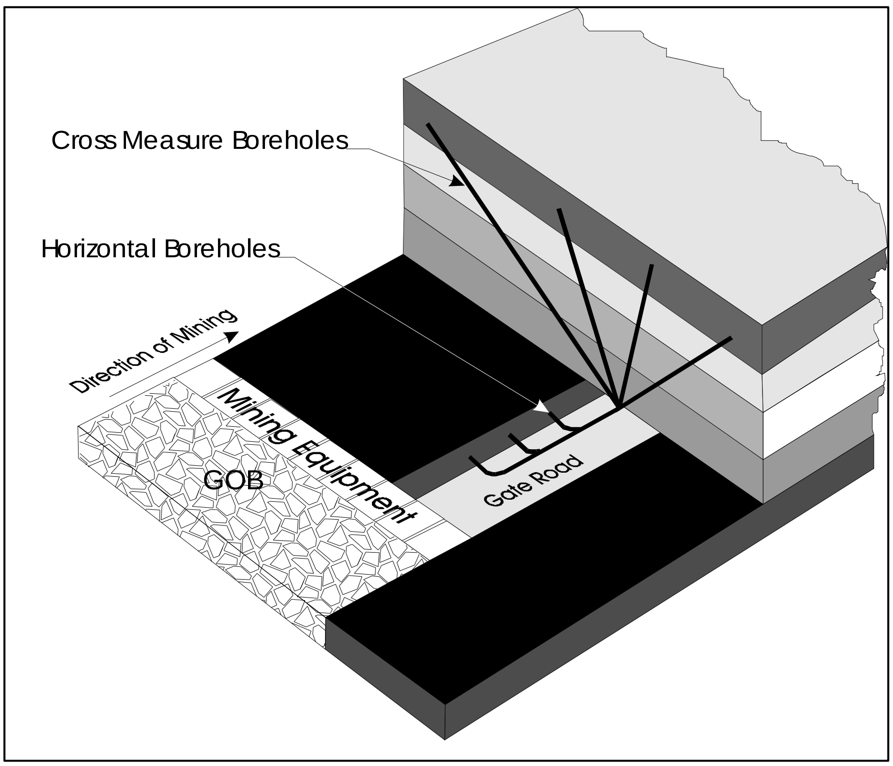
Initially, gob wells produce nearly pure methane. Over time, however, additional amounts of mine air can flow into the gob area and dilute the methane. The heating value of "gob gas" normally ranges between 300 and 800 Btu/cf. In some cases, it is possible to maintain nearly pure methane production from gob wells through careful monitoring and management. Jim Walter Resources, CONSOL, and Peabody are all using techniques for producing high-quality gas from gob wells by “upgrading” the gas to remove contaminants. Gas production rates from gob wells can be very high, especially immediately following the fracturing of the strata as mining advances under the well. Jim Walter Resources reports that gob wells initially produce at rates in excess of two million cubic feet per day. Over time, production rates typically decline until a relatively stable rate is achieved, typically in the range of 100 mcf/d. Depending on the number and spacing of the wells, gob wells can recover an estimated 30% to over 50% of methane emissions associated with coal mining (USEPA, 1990).

Twenty-three of the underground U.S. coal mines currently employing methane drainage systems use surface gob wells to reduce methane levels in mine working areas. Most mines release methane drained from gob wells into the atmosphere. Figure 2-3 illustrates a vertical gob well.

Horizontal Boreholes

Horizontal boreholes are drilled inside the mine (as opposed to from the surface) and they drain methane from the unmined areas of the coal seam, or from blocked out longwall panels shortly before mining takes place. These boreholes are typically 400 to 800 feet in length. Several hundred boreholes may be drilled within a single mine and connected to an in-mine vacuum piping system, which transports the methane out of the mine and to the surface. Most often, horizontal boreholes are used for short-term methane emissions relief during mining. Because methane drainage only occurs from the mined coal seam (and not from the surrounding strata), the recovery efficiency of this technique is low – approximately 10 to 18% of methane that would otherwise be emitted (USEPA, 1990). However, this methane typically can have a heating value of over 950 Btu/cf (USEPA, 1991). Approximately nine of the underground U.S. coal mines currently employing methane drainage systems use this technique to reduce the quantity of methane in mine working areas. Figures 2-3 and 2-4 illustrate horizontal boreholes.

Figure 2-4: Horizontal and Cross-Measure Boreholes



Longhole Horizontal Boreholes

Like horizontal boreholes, longhole horizontal boreholes are drilled from inside the mine in advance of mining. They are greater than 1000 feet in length and are drilled in unmined seams using directional drilling techniques. Longhole horizontal boreholes produce nearly pure methane with a recovery efficiency of about 50% and therefore can be used when high quality gas is desired. This technique is most effective for gassy, low permeability coal seams that require long diffusion periods. Both West Elk mine in Colorado and San Juan South mine in New Mexico have employed longhole horizontal boreholes in their drainage programs.

Cross-Measure Boreholes

Cross-measure boreholes degasify the overlying and underlying rock strata surrounding the target coal seam. These boreholes are drilled inside the mine and they drain methane with a heating value similar to that of gob wells. Cross-measure boreholes have been used extensively in Europe and Asia but are not widely used in the United States where surface gob wells are preferred. West Elk mine in Colorado has employed cross-measured boreholes in the past but did not find them effective. Figure 2-4 illustrates cross-measure boreholes.

Table 2-1
Summary of Drainage Methods

Method	***Description***	***Gas Quality***	***Drainage Efficiency***[a]	***Current Use in U.S. Coal Mines***[b]
Vertical Pre-Mine Wells	Drilled from surface to coal seam months or years in advance of mining.	Produces nearly pure methane.	up to 70%	Used by 6 mines.
Gob Wells	Drilled from surface to a few feet above coal seam just prior to mining.	Produces methane that is sometimes contaminated with mine air.	up to 50%	Used by 23 mines.
Horizontal Boreholes	Drilled from inside the mine to degasify the coal seam shortly prior to mining.	Produces nearly pure methane.	up to 20%	Used by 9 mines.
Longhole Horizontal Boreholes	Drilled from inside the mine to degasify the coal seam shortly prior to mining.	Produces nearly pure methane.	up to 50%	Previously used by at least 2 mines.
Cross-measure Boreholes	Drilled from inside the mine to degasify surrounding rock strata shortly prior to mining.	Produces methane that is sometimes contaminated with mine air.	Up to 20%	Not widely used in the U.S.[c]

Source: USEPA (1993); MSHA (2007); USEPA (2008)

[a] Percent of total methane liberated that is drained.

[b] Accurate only at the time of publication of this report; may vary often as mining progresses.

[c] Used at West Elk and San Juan mines at one time.

Utilization Options

Once recovered, coal mine methane is an energy source available for many different applications. Potential utilization options are pipeline injection, electricity generation, and direct use in on-site prep-plants or to fuel mine vehicles, or at nearby industrial or institutional facilities. Following is a discussion of various utilization methods. Table 2-2 shows the potential uses for gas produced in CMM drainage operations.

Table 2-2 Potential Uses for Gas Produced in CMM Drainage Operations		
Btu Quality	***Recovery Method(s)***	***Utilization Options***
High-Btu Gas (>950 Btu/scf)	• Vertical Wells • Horizontal Boreholes	• Natural gas pipeline fuel (>97% CH_4) • Chemical feedstock for ammonia, methanol, and acetic acid production (>89% CH_4) • Transportation fuel as compressed or liquefied gas
Medium-Btu Gas (350-950 Btu/scf)*	• Gob Wells • Cross-measure Boreholes	• Spiking with propane or other gases to increase Btu content to pipeline quality • Co-firing with coal in utility and industrial boilers • Fuel for internal combustion engines (>20% CH_4) • Enrichment through gas processing • Brine water treatment (>50% CH_4) • Greenhouse heating • Blast furnace use (as supplement to natural gas) • Production of liquefied gas (>80% CH_4) • Fuel for thermal dryers in a coal processing plant • Fuel for micro-turbines (>35% CH_4) • Fuel for heating mine facilities • Fuel for heating mine intake air • Use in fuel cells (>30% CH_4)
Ventilation Air	• Ventilation Air	• Combustion air in power production (<1.0% CH_4) • Combustion air in internal combustion engines or turbines (<1.0% CH_4) • Conversion to energy using oxidation technologies (<1.0% CH_4)
* In some countries (e.g., China) drained gas may be 350 Btu/scf or lower, but in the U.S. drained gas is well above 350 Btu/scf. Source: modified from USEPA (1999b)		

Pipeline Injection

Methane liberated during coal mining may be recovered and collected for sale to pipeline companies. Typical pipeline standards require a methane concentration of at least 95% methane. The key issues that will determine project feasibility are: 1) whether the recovered gas can meet pipeline quality standards; and 2) whether the costs of production, processing, compression, and transportation are competitive with other gas sources. Fortunately, the U.S. not only has an extensive pipeline network with many pipelines located in the major coal mining regions, it also benefits from natural gas prices that are relatively high compared to other countries.

U.S. experience demonstrates that selling recovered methane to a pipeline can be profitable for mining companies and is by far the most popular use method. As shown in Table 2-3, 12 U.S. mines currently sell methane from their drainage systems to local pipeline companies. Chapter 3 contains additional information on these projects.

Technical Feasibility

The primary technical consideration involved in collecting coal mine methane for pipeline sales is that the recovered methane must meet the standards for "pipeline quality"[10] gas. First, it must have a methane concentration of at least 95% and contain no more than a 2% concentration of inert gases (i.e., carbon dioxide, nitrogen, helium). Additionally, any non-methane hydrocarbons are usually removed from the gas stream for other uses. Hydrogen sulfide (which mixes with water to make sulfuric acid) and hydrogen (which makes pipes brittle) must also be removed before the gas is introduced into the pipeline system. Finally, any water or sand produced with the gas must be removed to prevent damage to the system. While coalbed methane requires water removal, it is often free of hydrogen sulfide and other impurities typically found in natural gas. With proper recovery and treatment, coalbed methane can meet the requirements for pipeline quality gas.

Table 2-3
Current Coal Mine Methane Pipeline Projects at Profiled Mines

Mining Company	***Number of Active Mines***	***State***
Walter Industries	3	Alabama
Cleveland-Cliffs	2	Alabama, West Virginia
Drummond Company	1	Alabama
Foundation Coal	2	Pennsylvania
CONSOL Energy	4	Virginia, West Virginia

Vertical degas wells are the preferred recovery method for producing pipeline quality methane from coal seams because pre-mining drainage ensures that the recovered methane is not contaminated with ventilation air from the working areas of the mine. Gob wells, in contrast, generally do not produce pipeline quality gas as the methane is frequently mixed with ventilation air. In certain cases, however, it is possible to maintain a higher and more consistent gas quality through careful monitoring and adjustment of the vacuum pressure in gob wells.

[10] Natural gas pipeline quality specifications differ from pipeline to pipeline. Pipeline standards are set by FERC and/or individual pipeline companies. Additional information on interstate natural gas pipeline quality specifications is available at http://www.beg.utexas.edu/energyecon/lng/documents/CEE_Interstate_Natural_Gas_Quality_Specifications_and_Interchangeability.pdf

It is also possible to *upgrade* or *enrich* gob gas to pipeline quality by using technologies that separate methane from carbon dioxide, oxygen, and/or nitrogen. Several technologies for separating methane are under development and may prove to be economically attractive and technically feasible with additional research (See EPA document "Upgrading Drained Coal Mine Methane to Pipeline Quality" available on the CMOP website at http://www.epa.gov/cmop/docs/red24.pdf). The first CMM upgrade facility in the U.S. was installed in 1997 in Southwestern Pennsylvania. Since then, 13 additional commercial-scale CMM upgrade facilities have come online at active and abandoned mines, and as of January 2008 three additional facilities are awaiting start up (USEPA, 2008c). One such project currently operating is at the Blue Creek No. 4, No. 5, and No. 7 mines operated by JWR where a cryogenic gas processing unit was installed in 2000 to upgrade medium-quality gas recovered from gob wells to pipeline quality gas. Pressure swing adsorption is also being utilized.

Another option for improving the quality of mine gas is known as *blending*, which is the mixing of lower Btu gas with higher Btu gas whose heating value exceeds pipeline requirements. As a result of blending, the Btu content of the overall mixture can meet acceptable levels for pipeline injection. For example, CONSOL is blending gob gas recovered from the VP 8 and Buchanan mines in Virginia with coalbed methane (CBM) production for pipeline injection.

Horizontal boreholes and longhole horizontal boreholes also can produce pipeline quality gas when the integrity of the in-mine piping system is closely monitored. However, the amount of methane produced from these methods is sometimes not large enough to warrant investments in the necessary surface facilities. In cases where mines are developing utilization strategies for larger amounts of gas recovered from vertical or gob wells, it may be possible to use the gas recovered from in-mine boreholes to supplement production.

For additional information on upgrading coal mine methane to pipeline quality see *USEPA, 2008c*. This report reviews current gas upgrading technologies available in the market for removal of typical CMM contaminants, provides examples of their successful commercial implementation, and compiles a list of vendors specific to nitrogen rejection systems, since nitrogen poses the biggest challenge to upgrading CMM.

Profitability

The overall profitability of recovering methane for pipeline injection will depend on a number of factors. These factors include the amount and quality of methane recovered (as discussed above), the capital and operating costs for wells, water disposal, compression and gathering systems, and most importantly, the price at which the recovered gas may be sold.

The costs for disposal of production water from vertical wells may be a significant factor in determining the economic viability of a project, as discussed later in this chapter ("Production Characteristics of Coalbed Methane Wells"). The cost of gas gathering lines is another consideration. Because costs for laying gathering lines are high, proximity to existing commercial pipelines is a significant factor in determining the economic viability of a coalbed methane project. Most coal mines are located within 20 miles of a commercial pipeline (See Chapter 6). However, in some cases, existing pipelines may have limited capacity for transporting additional gas supplies. Costs for laying gathering lines vary widely depending, in part, on terrain. The hilly and mountainous terrain in many mining areas increases the difficulty, and thus the cost, of installing gathering lines.

Another determinant of the overall profitability of a pipeline injection project is a mine's ability to find a purchaser for its recovered gas. A methane recovery project will also need to demonstrate that its recovered methane is of the requisite pipeline quality.

Power Generation

Coal mine methane may also be used as a fuel for power generation. Unlike pipeline injection, power generation does not require pipeline-quality methane. Gas turbines can generate electricity using methane that has a heat content of 350 Btu/cf. Mines can use electricity generated from recovered methane to meet their own on-site electricity requirements and can sell electricity generated in excess of on-site needs to utilities. An example is an 88 MW power generation station developed by CONSOL Energy and Allegheny Energy, placed near the VP 8 and Buchanan mines, fueled by coalbed methane and coal mine methane. Power generated is sold to the competitive wholesale market. The 88 MW project is one of the world's largest CMM-fired power plants. More typical are projects in the 1-10 MW range, such as a 1.2 MW project using internal combustion engines at the Federal No. 2 mine in West Virginia. Outside of the U.S., power generation is often the preferred option for using coal mine methane. Power generation projects using CMM are reported to be operating at coal mines in several other countries including China, Australia, United Kingdom, and Germany. When fully operational, the 120 MW CMM power project at Sihe coal mine in the southern part of Shanxi Province, China, will be the world's largest CMM-fired power plant.

Technical Feasibility

A methane/air mixture with a heating value of at least 350 Btu/cf is considered a suitable gaseous fuel for electricity generation. Accordingly, vertical degas wells, gob wells, and in-mine boreholes are all acceptable methods of recovering methane for generating power. Gas turbines, internal combustion (IC) engines, and boiler/steam turbines can all be adapted to generate electricity from coalbed methane. Fuel cells may also prove to be a promising option and were tested in 2003 at the Nelms Portal mine[11] in Ohio where a 250 kW Direct FuelCell®, manufactured by FuelCell Energy, Inc., was set up to deliver power to the local utility. The project, which was cost-shared by the Department of Energy, concluded that the use of fuel cells can generate power from CMM at high efficiencies (Steinfeld and Hunt, 2004).

Currently, the most likely generator choice for a CMM project would be either a gas turbine or an IC engine. Boiler/steam turbines are generally not cost effective in sizes below 30 MW, while gas turbines are not the optimal choice for projects requiring 1.5 MW or less. However, when used in the right applications gas turbines are smaller and lighter than IC engines and historically have had lower operation and maintenance costs.

While maintaining pipeline quality gas output from gob wells can be difficult, the heating value of gob gas is generally compatible with the combustion needs of gas turbines. One potential problem with using gob gas is that production, methane concentration, and rate of flow are generally not predictable; wide variations in the Btu content of the fuel may create operating difficulties. Equipment for blending the air and methane may be needed to ensure that variations in the heating value of the fuel remain within an acceptable range – approximately 10% allowable variability for gas turbines.

A potential advantage of using vertical pre-mine wells as the recovery method for power generation is that the quantity and quality of methane produced is more consistent than that of gob wells. Thus, problems stemming from variations in the heating value of the fuel would be minimized where vertical wells are employed. Another option is to blend high quality gas from vertical wells with lower quality gas from gob wells to ensure consistent quality. Horizontal boreholes also can produce gas of

[11] Not profiled in this edition of the report.

consistently high quality. The limited quantity of gas produced by this method would likely need to be supplemented by larger quantities of methane from vertical or gob wells, however.

The level of electric capacity that may be generated depends on the amount of methane recovered and the "heat rate" (i.e., Btu to kWh conversion) of the generator. For example, simple cycle gas turbines typically have heat rates in the range of 10,000 Btu/kWh, while combined cycle gas turbines could have heat rates of 7,000 Btu/kWh. Assuming a conservative heat rate of 11,000 Btu/kWh, and assuming that mines could recover 35% of total emissions, the level of electric capacity that could be sustained by the top ten methane-emitting mines would likely exceed 10 MW per mine.

Profitability: Power Generation for On-Site Use

Given their large energy requirements, coal mines may realize significant economic savings by generating power from recovered methane. Nearly every piece of equipment in an underground mine operates on electricity, including mining machines, conveyor belts, ventilation fans, and elevators. Much of the equipment at typical mines is operated 250 days a year, two shifts per day. Ventilation systems, however, must run 24 hours a day, 365 days a year, and they demand a considerable amount of electricity – up to 60% of the mine's total needs (USBM, 1992).

A mine's total electricity needs can exceed 24 kWh per ton of coal mined. Since many of the largest underground mines in the U.S. produce more than 3 million tons of coal annually, they may purchase over 72 million kWh of electricity annually. At average industrial electricity rates of five cents per kWh, a mine's electricity bill can exceed several million dollars a year.

Coal preparation plants, which are frequently located at or near large mines, also consume a great deal of energy. Preparation involves crushing, cleaning, and drying the coal before its final sale. Coal drying operations require thermal energy, which could be generated by a turbine or engine in a cogeneration cycle. Coal preparation generally requires an additional 6 kWh per ton of coal (ICF Resources, 1990a). CONSOL recovers approximately 2 mmcf/d from the VP 8 and Buchanan mines for use in their thermal dryer.

Among the main factors in determining the economic viability of generating power for on-site use are the total amount and flow of the methane recovered, the capital costs of the generator, the expected lifetime of the project, and the price the mine pays for the electricity it uses. A mine would need to be fairly large to recover an amount of methane that would justify the capital expenditures for a generator and other equipment needed for utilizing power on-site. Moreover, because the $/kW capital cost of a generator is relatively high in terms of the overall economics of a coalbed methane power project, the mine would need to generate power for several years in order to justify the capital investment. A final economic consideration is the cost of back-up power, which is typically supplied by a utility and is essential for mining operations given their safety considerations.

Profitability: Off-Site Sale to a Utility

Large and gassy coal mines may be able to generate electric power from recovered methane in excess of their own power requirements. In such cases, a mine may be able to profit from selling power to a nearby utility. Additionally, under some circumstances, a mine might arrange to sell electricity to a utility, but continue to purchase electricity from the utility for its own on-site use. The economic feasibility of selling power off-site would depend on the amount of electricity that could be generated, the incremental costs of selling power to a utility, and the price received for the electricity.

If a mine is generating power to meet its own electricity needs, the incremental costs of selling excess power off-site are relatively low. Normally, a coal mine already has a large transmission line running from a main transmission line to the mine substation. In most cases, this same line could be used to transmit power from the mine back to the utility. For some mines, an interconnection facility or line upgrades may be needed to feed this additional power into the main line.

Ventilation Air Methane Use Technologies

Ventilation air methane (VAM), the dilute methane emitted from mine ventilation shafts, is now recognized as an unused source of energy and a potent atmospheric greenhouse gas (GHG). A host of recently introduced technologies can reduce ventilation air methane emissions, while harnessing methane's energy, and can offer significant benefits to the world community.

USEPA has identified several viable technologies for destroying or beneficially using the methane contained in ventilation air:

(1) Two technologies based on a thermal oxidation process using thermal flow-reversal reactors (TFRR): The VOCSIDIZER™ developed by MEGTEC Systems (De Pere, Wisconsin, United States), and the VAMOX™ system from Biothermica Technologies Inc. (Montreal, Canada).
(2) A catalytic oxidation process called the Catalytic Flow-Reversal Reactor (CFRR), developed by a consortium of Canadian interests including CANMET.

These technologies employ similar principles to oxidize methane contained in mine ventilation airflows. Based on laboratory and field experience, these units can sustain operation (i.e., can maintain oxidation) with ventilation air having uniform methane concentrations down to approximately 0.1% and 0.2% for the CFRR and TFRR processes, respectively (Su et al., 2005). For practical field applications where methane concentrations are likely to vary over time, however, this analysis assumes that a practical average lower concentration limit at which oxidizers will function reliably is 1.5%.

In addition, a variety of other technologies such as boilers, engines, and turbines may use ventilation airflows as combustion air. At least two other technology families may also prove to be viable candidates for beneficially using VAM. These are VOC concentrators and new lean fuel gas turbines.

<u>Thermal Flow Reversal Reactor</u>

Figure 2-5 shows a schematic of the Thermal Flow Reversal Reactor (TFRR). The equipment consists of a bed of silica gravel or ceramic heat-exchange medium with a set of electric heating elements in the center. The TFRR process employs the principle of regenerative heat exchange between a gas and a solid bed of heat-exchange medium. To start the operation, electric heating elements preheat the middle of the bed to the temperature required to initiate methane oxidation (above 1,000°C or 1,832°F) or hotter. Ventilation air at ambient temperature enters and flows through the reactor in one direction and its temperature increases until oxidation of the methane takes place near the center of the bed.

The hot products of oxidation continue through the bed, losing heat to the far side of the bed in the process. When the far side of the bed is sufficiently hot, the reactor automatically reverses the direction of ventilation airflow. The ventilation air now enters the far (hot) side of the bed, where it encounters auto-oxidation temperatures near the center of the bed and then oxidizes. The hot gases again transfer heat to the near (cold) side of the bed and exit the reactor. Then, the process again reverses.

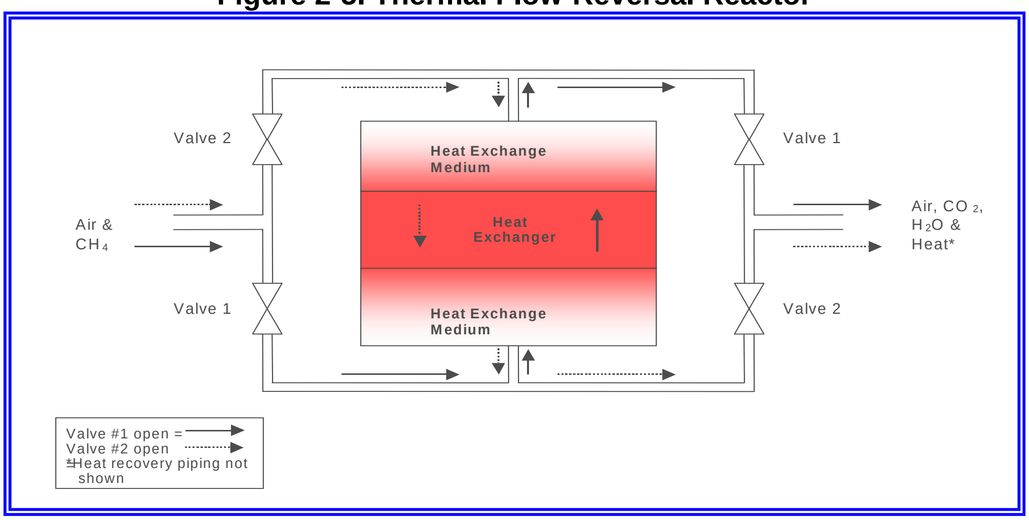
TFRR units are effectively employed worldwide to oxidize industrial VOC streams. Recently, their ability to oxidize VAM has been demonstrated in the field. In April 2007, the first ever U.S. demonstration of TFRR technology (VOCSIDIZER™) became operational at CONSOL Energy's Windsor Mine Portal, a closed, underground mine in West Virginia. The world's first commercial-scale VAM-to-power project became fully operational in September 2007 at BHP Billiton's West Cliff Colliery in New South Wales, Australia.

In May 2008, MSHA authorized Biothermica to conduct a demonstration project at JWR's Blue Creek No. 4 mine using the VAMOX™ regenerative thermal oxidation system to destroy VAM before it is released to the atmosphere. In 2009, the company plans to commission a second North American demonstration project at the Quinsam coal mine (Hillsborough Resources Limited) near Campbell River, in British Columbia. This project will use an alternative configuration of the VAMOX™ system, based on the same technology.

Catalytic Flow Reversal Reactor

Catalytic flow reversal reactors (CFRR) adapt the thermal flow reversal technology described above by including a catalyst to reduce the auto-oxidation temperature of methane by several hundred degrees Celsius (to as low as 350°C or 662°F). CFRR technology was developed exclusively for the treatment of methane in coal mine ventilation air. CANMET has demonstrated this system in pilot plants and is now in the process of licensing the design. CANMET is also studying energy recovery options for profitable turbine electricity generation. Injecting a small amount of methane (gob gas or other source) increases the methane concentration in ventilation air and can make the turbine function more efficiently. Waste heat from the oxidizer is also used to pre-heat the compressed air before it enters the expansion side of the gas turbine.

Figure 2-5. Thermal Flow-Reversal Reactor



Energy Conversion from a Flow-Reversal Reactor

There are two primary options for converting the heat of oxidation from a flow-reversal reactor to electric power, which is the most marketable form of energy in most locations:

- *Use water as a working fluid.* Pressurize the water and force it through an air-to-water heat exchanger in a section of the reactor that will provide a non-destructive temperature environment (below 800^{o}C or 1472^{o}F). Flash the hot pressurized water to steam and use the steam to drive a steam turbine-generator. If a market for steam or hot water is available, send exhausted steam to that market. If none is available, condense the steam and return the water to the pump to repeat the process.
- *Use air as a working fluid.* Pressurize ventilation air or ambient air and send it through an air-to-air heat exchanger that is embedded in a section of the reactor that stays below 800^{o}C (1472^{o}F). Direct the compressed hot air through a gas turbine-generator. If gob gas is available, use it to raise the temperature of the working fluid to more nearly match the design temperature of the turbine inlet. Use the turbine exhaust for cogeneration, if thermal markets are available.

Since affordable heat exchanger temperature limits are below those used in modern prime movers, efficiencies for both of the energy conversion strategies listed above will be fairly modest. The use of a gas turbine, the second method listed, is the energy conversion technology assumed for the cost estimates in this report. At a VAM concentration of 0.5% one vendor expects an overall plant efficiency in the neighborhood of 17% after accounting for power allocated to drive the fans that force ventilation air through the reactor.

<u>Other Technologies</u>

EPA has also identified other technologies that may be able to play a role in and enhance opportunities for VAM oxidation projects. These are briefly described below.

Concentrators

Volatile organic compound (VOC) concentrators offer another possible economical option for application to VAM. During the past 10 years the use of such units to raise the concentration of VOCs in industrial-process air exhaust streams that are sent to VOC oxidizers has increased. Smaller oxidizer units are now used to treat these exhaust streams, which in turn has reduced capital and operating costs for the oxidizer systems. Ventilation air typically contains about 0.5% methane concentration by volume. Conceivably, a concentrator might be capable of increasing the methane concentration in ventilation airflows to about 20%. The highly reduced gas volume with a higher concentration of methane might serve beneficially as a fuel in a gas turbine, reciprocating engine, etc. Concentrators also may prove effective in raising the methane concentration of very dilute VAM flows to levels that will support oxidation in a TFRR or CFRR.

Lean Fuel Gas Turbines

A number of engineering teams are striving to modify selected gas turbine models to operate directly on VAM or on VAM that has been enhanced with more concentrated fuels, including concentrated VAM (see “Concentrator” section above) or gob gas. These efforts include:

- ***Carbureted gas turbine.*** A carbureted gas turbine (CGT) is a gas turbine in which the fuel enters as a homogeneous mixture via the air inlet to an aspirated turbine. It requires a fuel/air mixture of 1.6% by volume, so most VAM sources would require enrichment. Combustion takes place in an external combustor where the reaction is at a lower temperature (1200°C or 2192°F) than for a normal turbine thus eliminating any NOx emissions. Energy Developments Limited (EDL) of Australia has tested the CGT on ventilation air at the Appin coal mine in New South Wales, Australia.

- ***Lean-fueled turbine with catalytic combustor.*** CSIRO Exploration & Mining of Australia, a government research organization, is developing a catalytic combustion gas turbine (CCGT) that can use methane in coal mine ventilation air. The CCGT technology being developed oxidizes VAM in conjunction with a catalyst. The turbine compresses a very lean fuel/air mixture and combusts it in a catalytic combustor. CSIRO hopes to operate the system on a 1.0% methane mixture to minimize supplemental fuel requirements. In 2006, CSIRO, together with China's Shanghai Jiaotong University and Huainan Coal Mining Group, announced plans to construct the first pilot-scale demonstration of a low-heating value gas turbine (VAMCAT) at a coal mine in China. The unit will be powered by about 1% methane in ventilation air with an estimated power output of 10-30 kW (USEPA, 2006a).

- ***Lean-fueled catalytic microturbine.*** Two U.S. companies, FlexEnergy and Capstone Turbine Corporation, are jointly developing a line of microturbines, starting at 30 kW that will operate on a methane-in-air mixture of 1.3%.

- ***Hybrid coal and VAM-fueled gas turbine.*** CSIRO is also developing an innovative system to oxidize and generate electricity with VAM in combination with waste coal. CSIRO is constructing a 1.2-MW pilot plant that cofires waste coal and VAM in a rotary kiln, captures the heat in a high-temperature air-to-air heat exchanger, and uses the clean, hot air to power a gas turbine. Depending on site needs and economic conditions, VAM can provide from about 15 to over 80% (assuming a VAM mixture of 1.0%) of the system's fuel needs, while waste coal provides the remainder.

<u>VAM Used as an Ancillary Fuel</u>

VAM can also be used as an ancillary or supplemental fuel. Such technologies rely on a primary fuel other than VAM and are able to accept VAM as all or part of their combustion air to replace a small fraction of the primary fuel. The largest example of ancillary VAM occurs at the Appin and Tower Collieries in Australia, where 94 one-MW Caterpillar engines used mine ventilation air containing VAM as combustion air. In addition, the Australian utility, Powercoal, is installing a system to use VAM as combustion air for a large coal-fired steam power plant. The U.S. Department of Energy funded a research project to use VAM in concentrations up to 0.5% as combustion air in a turbine manufactured by Solar. When waste coal combustion is maximized and VAM use is limited to prescribed levels of combustion air, the CSIRO hybrid coal and VAM project described in the preceding paragraph could be considered ancillary VAM use.

<u>Project Economics for Ventilation Air Methane Use Technologies</u>

Many of the technologies for VAM use are still in the developmental stage, and cost information is still limited. The costs for simply using the VAM as combustion air either in reciprocating engines or turbines is negligible, the only costs being construction and operation of equipment to move the air to the generator sets. Additional maintenance of the engines or turbines may be necessary if excess moisture and dust are present in the mine ventilation air. Developers of the lean-burn turbines are reporting that they can produce 30-100 kW units for about $1,000-2,000 per kW while commercial production of larger scale units (200 kW – 2 MW) would drive down the costs significantly to $600-$1,000 per kW.

The majority of economic data available is for the flow reversal reactors. In 2003, EPA released the report, "Assessment of the Worldwide Potential for Oxidizing Coal Mine Ventilation Air Methane," the most comprehensive assessment to date of the marginal abatement costs of VAM use technologies.

With methane abatement costs at $3.00 per ton of CO_2e, VAM-derived power projects in the U.S. could theoretically create 457 MW of net useable capacity. If the equipment value for each project were rounded to $10 million, the total equipment market estimate for the U.S. would be over $1.2 billion. Finally, the annual revenues that could accrue from such power sales in the country could amount to over $120 million (USEPA, 2003).

Local Use

In addition to pipeline injection, power generation, and ventilation air methane use, coal mine methane may be used as a fuel in on-site preparation plants or vehicle refueling stations, or it can be transported to a nearby coal-fired boiler or other industrial or institutional facilities for direct use.

Nearly all large underground coal mines have preparation plants located nearby. Mines have traditionally used their own coal to fuel these plants, but there is the potential to use recovered methane instead. Currently, CONSOL uses recovered methane to fuel the thermal dryer in one of its preparation plants. In Poland, several coal mines have used recovered methane to fuel their coal drying plants.

Another option for on-site methane use may be as a fuel for mine vehicles. Natural gas is much cheaper and cleaner than diesel fuel or gasoline, and internal combustion engines burn it more efficiently.

In addition to on-site methane use, selling recovered methane to a nearby industrial or institutional facility may be a promising option for some mines. An ideal gas customer would be located near the coal mine (within five miles) and would have a continuous demand for gaseous fuel. Coal mine methane could be used to fuel a cogeneration system, to fire boilers or chillers, or to provide space heating. In some cases, local communities may find that the availability of an inexpensive fuel source from their local mine can help them attract industry and generate additional jobs.

Additionally, there are numerous international examples of mine gas being used for industrial purposes. For example, in Ukraine and Russia, recovered coal mine methane is used in coal-fired boilers located at the mine-site. In the Czech Republic, coal mine methane is used in nearby metallurgical plants. In Poland, recovered coal mine methane is used as a feed-stock fuel in a chemical plant. In China, CMM has been used in carbon black plants.

Finally, co-firing methane with coal in a boiler is another potential utilization option, particularly for mines that are located in close proximity to a power plant. A few of the mines profiled in this report are located within a few miles of a coal-fired plant (for example, Robinson Run No. 95 mine is located about two miles from Allegheny Power's Harrison Plant).

Flaring

Flaring (or oxidizing) converts methane to carbon dioxide. Emitting carbon dioxide is much less harmful than direct emissions of methane in terms of the impact on global warming. For purposes of greenhouse gas reductions, the value of recovering one ton of methane and using it to generate energy (in lieu of burning natural gas from a traditional source) is equivalent to a 23 ton reduction in carbon dioxide emissions. If mine emissions are flared without using the combustion to displace energy from other sources, flaring yields greenhouse gas reductions equal to 87.5% (18.25 ton CO_2 equivalent reduction) of those achievable through recovery and use (Lewin, 1997).

To date, flaring has not been implemented at active mines in the U.S. The principal concern expressed by the coal industry is the inherent safety needed to prevent flame propagation leading to an underground explosion (Lewin, 1995). Adoption of flaring at active mines requires the acceptance of miners, MSHA, union parties, and mine owners. Through a series of reports, EPA has outlined the benefits of flaring and proposed a conceptual flare design to meet the safety concerns (USEPA, 1999a).

Green Pricing Projects

With the advent of competition in the electric utility industry, utilities are recognizing the need to provide new services to customers. One such service is "green pricing". Under green pricing, customers can choose the type of electricity they purchase. Customers can choose conventional power, which they can purchase at a standard rate, or they can purchase green power at a slightly higher rate. As part of the green pricing program, for every customer who commits to pay the higher rate, the utility pledges to buy enough "environmentally friendly" energy to completely offset the customer's share of conventionally generated electricity. In 2000, the State of Pennsylvania Public Utility Commissions included CMM as part of their green pricing program.

Another result of electric utility industry deregulation is the emergence of laws and regulations to encourage investment in renewables. Twenty-four States and the District of Columbia have enacted “renewable portfolio standards” (RPS), which requires electric utilities to generate a portion of their electricity through qualifying renewable technologies by a specific date in the future. The requirements under the various standards and the definition of renewable energy vary by state. Currently, Pennsylvania is the only state with an RPS to include CMM as a qualifying renewable source (EERE, 2007).

Barriers to the Recovery and Use of Coal Mine Methane

While a number of U.S. coal mines are already selling recovered methane to pipelines, some project opportunities that would seem to be profitable have not been undertaken at other mines. Currently, a number of problems and disincentives distort the economics of coal mine methane projects. These obstacles include technical challenges, unresolved legal issues concerning ownership of the coalbed methane resource, power prices, and pipeline capacity constraints.

Technical Challenges

Gas Production

Degasification wells at coal mines have production characteristics that differ from conventional gas wells in a variety of respects. One important difference is the amount of control the developer has in terms of the gas flow. With conventional gas wells, the gas flow may be controlled, or completely halted, at the discretion of the operator. This provides the operator with flexibility as to when the gas is sold. Vertical pre-mine degasification wells can be controlled as their production is not directly related to mining activities. In-seam and gob wells, however, are not subject to the same control by virtue of their purpose. These wells are used primarily to drain a mine of methane for safety reasons. As such, the feasibility of turning off and on an in-seam or gob well depends on safety first and gas production second.

Water Production

Another area in which technical challenges may arise is water disposal. In many instances, vertical coalbed methane wells will produce water from the coal seam and surrounding strata. Water is also produced during conventional mining operations, but some states have adopted separate regulations for water produced in association with coalbed methane operations and for water produced as a result of mining operations. For mines located near fresh water bodies or other vulnerable areas, surface water disposal may not be environmentally acceptable. Several alternative disposal and treatment methods are in use or under development, including deep well injection and other surface treatment approaches. These treatments may have higher costs associated with them, and in some cases additional research is needed to address technical issues.

Ownership of Coalbed Methane

Unresolved legal issues concerning the ownership of coalbed methane resources have traditionally been one of the most significant barriers to coalbed methane recovery. Without a clear understanding of who owns CMM and how the rights to its profitable utilization can be obtained, projects may be viewed as too risky to gain support from the investor community.

In the U.S., industry lacks a uniform legal framework governing CMM ownership. In most cases, a coal lease holder does not have automatic rights to CMM and must work with the gas lease holder, the surface owner, the government, or a combination of the three to resolve the issue. Ownership issues, which remain a serious obstacle to methane recovery, are largely dependent on whether the CMM resources and rights are controlled by the U.S. Government – as is the case in several western states – or if they fall on private lands – such as in much of the eastern U.S. – where ownership of the mineral resources is governed by state laws.

Ownership on Federal and private lands are discussed briefly below. For additional information on coal mine methane ownership issues, see the Fall 2007 *Coalbed Methane Extra* (USEPA, 2007a).

Federal Lands

A developer on federal lands must hold a gas lease in order to put a CBM or CMM resource to beneficial use. If a company holding a coal lease wants to utilize its CMM emissions, for example, it must follow the federal leasing procedures in place for conventional natural gas as prescribed by the BLM. Generally, utilization and/or sales of CMM requires a valid gas lease, regardless of end use. If the leased gas is used by the mine or mine company, used for power production, or sold to another party, gas royalties must be paid to the BLM. If no lease is held for the gas, it may only be vented to the atmosphere for safety purposes as set out by the Mine Safety and Health Administration (MSHA).

A split estate arises in the event that gas rights are leased to an entity other than the mining company. When this happens, situation-specific arrangements have to be made in order to accommodate both lessees.

Private Lands

When the western U.S. was being settled by homesteaders, the eastern U.S. was already under private ownership. As disputes between coal, gas, and surface owners developed, various state laws were established to govern CMM and CBM ownership. Where possible, common law rules are generally followed. Today, when interpreting deeds, contracts, and leases, the goal is to implement the intentions of the parties, using evidence where necessary. When split estate property is involved, a number of issues must be considered to accommodate all parties. One consideration is whether the activities of either the surface or various mineral estates cause reasonable or unreasonable interference for the other estate(s) and if such activities are necessary or incidental.

Case law resolution is required when the deed or lease is silent on key issues concerning allocation of multiple subsurface resources. For example, in Kentucky, Virginia, and Wyoming, legal precedent dictates that the coal lessee rights apply only to the coal, and do not automatically convey any rights to the associated gas (CBM). Similar cases have occurred in other states as well. In Alabama, Illinois, Montana, and Pennsylvania, it was determined that CBM rights are controlled by the coal estate.

Power Prices

The primary factor contributing to the slow development of CMM-fueled power generation is the low price of electricity in many U.S. coal producing regions. When comparing the economics of power generation to other alternatives, relatively low electricity prices have made power projects (either for on-site use or sales to a utility) less attractive, regardless of the designated end-use for the power.

Pipeline Capacity Constraints

The production characteristics of coalbed methane wells present difficulties in the context of the natural gas and pipeline industries. Much of the consumer demand for natural gas is seasonal in nature.

In much of the U.S. there is limited pipeline capacity relative to supply. As a result, local pipelines may not be able to accept the gas supplied from coalbed methane projects on a continuous, uninterrupted basis. One area particularly affected is the Appalachian region.

Storage of coalbed methane in depleted natural gas reservoirs or abandoned mines is a potential solution to resolve issues of fluctuations in demand for gas or pipeline capacity. EPA has investigated the potential for storing methane recovered from active coal mines in nearby abandoned coal mines, concluding that if the abandoned mine were to meet certain criteria, a project could be sustainable (USEPA, 1998).

3. Overview of Existing Coal Mine Methane Projects

3. Overview of Existing Coal Mine Methane Projects

This chapter discusses 9 distinct methane recovery and use projects at 14 U.S. underground mines (each of the mines is also profiled in Chapter 6). In 2006, total methane sales from U.S. coal mine methane projects was over 46 billion cubic feet, or 21 MMTCO_2e.[12] Assuming a wellhead gas price of roughly $6.40 per thousand cubic feet[13], if all recovered gas were sold to pipelines, these projects collectively grossed approximately $295 million annually. Additionally, these projects have greatly reduced mine ventilation costs and have improved safety conditions for miners.

The projects in Alabama, Colorado, Pennsylvania, Virginia, and West Virginia employ a variety of degasification techniques, including vertical wells (pre-mining degasification), gob wells, and in-mine boreholes. Regardless of the degasification system employed, all mines have been able to recover large quantities of gas suitable for use in various applications. Following is a brief overview of the existing projects, by state. Table 3-1, at the end of this chapter, summarizes the major characteristics of the existing projects.

<u>Alabama</u>

- Five mines in Alabama recover and sell methane:
    - Blue Creek No. 4, owned by Walter Industries
    - Blue Creek No. 5, owned by Walter Industries
    - Blue Creek No. 7, owned by Walter Industries
    - Oak Grove, owned by Cleveland-Cliffs
    - Shoal Creek, owned by Drummond Company

Walter Industries

<u>Blue Creek No. 4, No. 5, and No. 7 Mines</u>

Located in Tuscaloosa County, Alabama, the Jim Walter Resources (JWR)-operated mines are among the deepest and gassiest mines in the country. Opened in the early to mid-1970's, the mines cover an 80,000 acre area and have vertical shafts ranging from 1,300 to 2,100 feet in depth. The in-situ gas content of coal is about 500 to 600 cubic feet per ton and the total amount of methane liberated from these mines is estimated to be between 3,800 – 4,500 cubic feet per ton of coal produced.

JWR has been a leader in the development of coal mine methane recovery projects in the United States. The company's Blue Creek mines – the Nos. 4, 5[14], and 7 mines – recovered and sold approximately 46.5 million cubic feet of gas per day in 2006. Methane is produced from these mines using three recovery methods: 1) vertical degasification (holes drilled from the surface into the virgin coalbed); 2) horizontal degasification (holes drilled in the coalbed from active workings inside the mine); and 3) a gob degasification program (holes drilled from the surface into the caved area behind the longwall faces).

Since the late 1980s, JWR has been producing between 25 – 50 mmcf/d of methane. JWR owns half of Black Warrior Methane Corp. (BWM), which extracts methane from the coal seams owned or leased by JWR. In 2006, there were 415 wells producing approximately 13.8 Bcf (JWR's share was

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[12] Methane emissions may be converted to a measure equivalent to carbon dioxide, using a conservative conversion factor that methane is 21 times more potent than carbon dioxide over a 100 year time frame.
[13] EIA – average wellhead price for 2006 < http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm >.
[14] No. 5 mine completed underground mining in December 2006.

7.7 Bcf, including 1.4 Bcf from its low quality gas operations). As of December 2007, the number of wells has declined to 408, producing 12.9 Bcf, with JWR's share being 7.2 Bcf (including 1.4 Bcf from LQG operations). JWR expects gas production levels to remain between 6.8 to 7.2 Bcf in 2008 (Walter Industries, 2007 and 2008). The quantity of methane recovered in 2006 represents 72% of total methane liberated from the mines. Recovery from vertical pre-mine wells in 2006 made up 47% of production, while gob wells and in-mine boreholes made up the remaining 53% (this includes a 7% compressor loss adjustment).

Cleveland-Cliffs

<u>Oak Grove Mine</u>

Cleveland-Cliffs' Oak Grove mine produces methane for pipeline sales. Operated by Oak Grove Resources, Oak Grove came under management by Cleveland-Cliffs after their 2007 acquisition of PinnOak Resources (along with Pinnacle mine in West Virginia). Oak Grove is located in the east-central portion of the Black Warrior Basin in Jefferson County, Alabama. The target seam for mining is the Blue Creek bed of the Mary Lee coal group. The coal is mined at a depth of approximately 1,150 feet.

The effectiveness of a large-scale pattern of stimulated vertical wells in reducing the gas content of a coalbed was first demonstrated at the Oak Grove mine in 1977. This was the first large-scale coal seam degasification project in the United States using vertical wells, as well as one of the first coalbed methane production projects. After 10 years, the original wells had produced a total of 3.2 Bcf (billion cubic feet) of methane that will never need to be controlled in the underground mine environment. Most of the wells in the field, however, are well beyond the near-term mine plan. Pre-drainage wells that were mined-through in 2006 produced 205 mmcf. In addition to the vertical wells drilled in advance of mining, Oak Grove mine has also utilized both horizontal and gob wells for methane drainage, primarily to increase the safety of the underground mine. Since 1997, as many as 15 gob and horizontal wells have been in production in a given year. In 2006, ten of these wells remained in production, producing 65 mmcf.

Because the sole goal of other companies drilling in the Oak Grove degasification field is commercial methane production, rather than reducing emissions from future mining operations, most of the wells drilled since 1985 have been spaced on a 160-acre (or greater) pattern. While these wells do drain methane from the area to be mined, the wider well spacing does not drain the coal as effectively as would a true vertical pre-mine drainage program. Cleveland-Cliffs has invested in business improvement initiatives and safety activities designed to enhance future coal production. These investments have reduced the company's recent coal production. Additionally, a difficult labor situation has slowed progress of the underground drainage program.

Drummond Company

<u>Shoal Creek Mine</u>

Drummond Coal's Shoal Creek mine began producing coal in 1994. The mine entry is located in the Oak Grove Field, but mining will progress into the White Oak Field. In the past, Shoal Creek has used vertical pre-mine, horizontal, and gob wells to drain methane. The pre-mine wells in the White Oak Field are operated by Sonat Exploration. Nearly 37 wells produced about 1 mmcf/d of methane for pipeline sales in 2003. In 2003, there were six gob wells, which produced 415 mcf/d, in addition to 31 horizontal wells that produced 580 mcf/d.

In 2006, gas production from pre-mine drainage wells totaled 52 mmcf. Future mining at Shoal Creek will be in reserves that were not adequately drained by vertical wells due to water issues, so it is likely this mine will be gassier in the future. However, Drummond is not focused on gas sales, and difficult mining conditions and labor issues have impeded expansion at the mine.

Colorado

There is one methane recovery and use project underway in Colorado. The project is taking place at the West Elk mine, which is owned by Arch Coal and operated by Mountain Coal Co.

Arch Coal

West Elk Mine

West Elk began recovering methane in 2003 to heat mine ventilation air on site. In 2006, EPA estimates that the mine recovered and used approximately 170 mmcf of methane, although the exact amount is not measured.

Pennsylvania

In 2006, there was one methane recovery and use project in Pennsylvania, involving two mines owned by Foundation Coal. Both mines are located in close proximity to each other and are therefore discussed together.

Foundation Coal

Cumberland and Emerald Mines

Foundation currently runs two longwall mines on three faces at Cumberland and Emerald mines. Gas is produced from in-seam boreholes and gob wells. In 2005, the longwall face at Emerald was expanded to 1,450 feet resulting in increased coal production.

In early 2008, Foundation Coal acquired a 49% stake in Target Drilling, the company that drilled test CBM wells for Foundation in 2007. Foundation Coal recently completed a study of the methane contained in controlled acreage in Northern Appalachia. The reservoir engineering study, coupled with current gas production activity, indicates recoverable gas exceeding 300 Bcf. Foundation will focus on the development of more than 150,000 acres of CBM lands in Northern Appalachia.

Together, EPA estimates that the Cumberland and Emerald mines drained and injected into pipelines 5.7 mmcf/d of methane in 2006, while liberating a total of 17.5 mmcf/d.

Virginia

The commercial potential of coalbed methane recovery in Virginia has long been recognized, but complicated issues regarding gas ownership, as well as the lack of pipeline capacity in southwest Virginia, delayed commercial coalbed methane recovery in this area until the early 1990's. There is one methane recovery and use projects currently underway in Virginia, which takes place at the Buchanan and VP 8 mines. CONSOL Energy owns both mines.

CONSOL Energy

Through CNX Gas Corporation, CONSOL recovers methane from two of the gassiest mines in the southwestern region of Virginia: Buchanan and VP 8. One of these mines, VP 8, was born out of the consolidation of the VP 5 and VP 6 mines in 1994. CONSOL has operated the adjacent Buchanan mine since 1983. The company has developed extensive degasification programs on both their properties, and continues to invest in vertical pre-mine wells. Although more gas can be successfully drained if a vertical pre-mine well has been in place for a long period, CONSOL has been opting for an advance drainage time frame that adequately balances the risk of investing in a vertical pre-mine drainage system with that of the company's mining plans. Thus, the company uses a three to five year advance degasification program to the extent that this can be feasibly coordinated with the company's overall mining strategies.

Currently, CONSOL produces gas for pipeline sales, on site use, and power generation. The total methane drained at these two CONSOL mine properties in Virginia totaled 79.7 mmcf/d in 2006 and included some CBM.

Of the 79.7 mmcf/d of methane that CONSOL currently recovers, approximately 63.9 mmcf/d can be attributed to emissions reduction at the mines. Of the total recovered methane, gob wells and in-mine horizontal boreholes account for approximately 67% of methane production at the mines. Vertical pre-mine wells that have been mined through and impact emissions reductions at the mines account for the remaining 33%. This production from the vertical wells represents only about one third of the total gas sales occurring in the coals being drained ahead of mining.

Buchanan Mine

A deep and gassy mine, Buchanan is actively mining at a depth of about 1,500 feet and has an in-situ gas content of about 5,270 cf/ton. Beginning in May 1995, Buchanan began using recovered methane, instead of coal, as fuel in its thermal dryer. As of May 1997, the thermal dryer consumed approximately 1.5 mmcf/d, or 547.5 mmcf/year (CONSOL, 1997). In addition, over 7 mmcf/d was recovered from gob and horizontal wells at the mine in 2001. After 2001, CONSOL began reporting methane recovered from the Buchanan and VP 8 projects together.

VP 8 Mine

Gas sales started in May 1992 at a rate of 3 mmcf/d. Over the next twelve months, production had grown to more than 30 mmcf/d (about 11 Bcf per year). In 2001, gas sales exceeded 60 mmcf/d via three methods, vertical pre-drainage wells, horizontal boreholes, and gob wells. Additionally, CONSOL recovers methane from abandoned areas at the VP 8 and Buchanan mines. Once a methane drainage program from an abandoned area is completed, that area is sealed and no further methane extraction takes place (CONSOL, 1997). After 2001, CONSOL began reporting methane recovered from the Buchanan and VP 8 projects together. In the spring of 2006, underground mining at VP 8 was completed due to lack of reserves, however gas recovery continues.

CONSOL Energy and Allegheny Energy operate a combined power project at the VP 8 and Buchanan mines in Virginia. The 88 MW power generation station is currently the second largest CMM power plant in the world, although it is used only for power peaking and is operated very infrequently.

West Virginia

There are three distinct methane recovery and use projects currently underway at four mines in West Virginia. These projects are taking place at the Blacksville No. 2, Loveridge No. 22, Federal No. 2, and Pinnacle mines. Blacksville No. 2 and Loveridge No. 22 are owned by CONSOL Energy, Federal No. 2 is owned by Patriot Coal, and Pinnacle is owned by Cleveland-Cliffs.

CONSOL Energy

Blacksville No. 2 and Loveridge No. 22 Mines

CONSOL and CBE Inc. are undertaking a gas enrichment and sales project at the Blacksville No. 2 mine. In 1997, CBE began selling enriched gas directly to the pipeline. The project captured as much as 4 mmcf/day from the mine, and removed carbon dioxide, oxygen, and nitrogen from the gas using catalytic, amine, and cryogenic processes, respectively. Columbia Energy Services purchases the resulting pipeline-quality gas. The enrichment plant is able to process 5-6 mmcf/d of gas whose methane content (prior to enrichment) is about 80-85%. The project can be expanded to process 10-12 mmcf/d. Operational problems in 2000 and 2001 have kept the project from maintaining its maximum output. Since that time, CONSOL has assumed full responsibility for the project and expects to optimize the production. Loveridge No. 22 began recovering and using methane in 1997. Since then, recovery and use at the mine was halted until the practice was restarted in 2005.

Patriot Coal

Federal No. 2 Mine

Federal No. 2 currently drains methane using vertical gob wells. The mine markets gas recovered from some higher quality gob wells to a natural gas pipeline. This gas project is a joint venture with Dominion Gas Company. Dominion recovered approximately 0.8 mmcf/d in 2003. The project at Federal No. 2 continues to expand as more sealed longwall panels become available to drain. In 2006, 75 mmcf was recovered and used at Federal No. 2 mine.

Cleveland-Cliffs

Pinnacle Mine

Pinnacle mine, located in West Virginia, produces methane for pipeline sale. Currently, the mine sells recovered coal mine gas to a local pipeline company. Methane recovery in the area had been hindered by high road and location costs. CDX Gas uses a horizontal borehole drainage system (the Z-Pinnate Horizontal Drilling and Completion technology).[15]

In 2006 the Pinnacle mine recovered and sold approximately 4.6 mmcf/d of gas from its pre-mine drainage wells. In addition, the mine uses gob vent boreholes to drain methane, but currently does not recover the gob gas.

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[15] Under this dual system approach, a vertical well was drilled first and the target coal seam was cavitated. Then a horizontal hole was kicked off from a second well, which intersected the cavity of the first well. The cavity acts as a down-hole water separator, retaining water while gas flows to the production well. Finally, a lateral well was drilled through the cavity along the coal seam for up to 4,800 feet. When the drill was pulled back along this main branch, paired branches were drilled at 45 degrees to the main, yielding a “barbed” appearance from a plan view. This process continued back toward the production well, creating a series of barbed branches that CDX calls a “pinnate” drilling pattern. Four of these patterns can be drilled from a central well.

Summary

Table 3-1 summarizes the methane recovery and use projects discussed in this chapter.

Table 3-1: Summary of Existing Methane Recovery and Use Projects

Mine Name	Mine Location (State)	Approximate Amount of Gas Used in 2006*	Methane Use Option	Notes
Blue Creek No. 4 Blue Creek No. 5 Blue Creek No. 7	Alabama	46.5 mmcf/day	Pipeline Sales	The three mines collectively liberated 64.2 mmcf/d of gas in 2006.
Oak Grove	Alabama	0.7 mmcf/day	Pipeline Sales	Most of the production in the Oak Grove Field is beyond the limits of the mine plan.
Shoal Creek	Alabama	0.1 mmcf/day	Pipeline Sales	Most of the production from the White Oak Field is outside the limits of the mine plan and is therefore not included in this summary.
West Elk	Colorado	0.5 mmcf/day	On-Site Use Heaters	Began recovering methane in 2003.
Cumberland Emerald	Pennsylvania	5.7 mmcf/day	Pipeline Sales	Began recovering methane in 2005.
Buchanan VP #8	Virginia	63.9 mmcf/day	Pipeline Sales On-Site Use Power Generation	These two mines collectively produced 79.7 mmcf/day of gas in 2006, of which 63.9 mmcf/d contributes to emissions reduction at the mines. A small portion (2 mmcf/d) of the total gas production is used on-site in a thermal dryer.
Blacksville No. 2 Loveridge No. 22	West Virginia	4.3 mmcf/day	Pipeline Sales	The two mines collectively used 4.3 mmcf/d and liberated 16.8 mmcf/d in 2006. CONSOL began reporting methane recovered from the two mines together in 2005.
Federal No. 2	West Virginia	0.2 mmcf/day	Pipeline Sales On-Site Use Power Generation	Project continues to expand as more longwall panels become available to drain.
Pinnacle	West Virginia	4.6 mmcf/day	Pipeline Sales	A unique, horizontal pre-mine drainage program is utilized.

*EPA only includes gas drained and used from wells that are located within the coal mining plan, and only counts the gas as “coal mine methane” rather than coalbed methane once the well is mined through.

4. Guide to the Mine Profiles

4. Guide to the Mine Profiles

This report contains profiles of coal mines that are potential candidates for the development of methane recovery and use projects, as well as those mines that have already installed methane recovery and use systems. The profiled mines were selected primarily on the basis of their annual methane emissions from ventilation systems as recorded in a Mine Safety and Health Administration database (MSHA, 2007). While EPA believes that this report is a comprehensive listing of the best candidates for cost-effective methane recovery projects, EPA recognizes that as conditions change some promising candidate mines may not be identified here.

The mine profiles presented in this report are designed to assist in identifying mines that can sustain a profitable methane recovery and use project. Each mine profile is comprised of the following sections:

- Geographic data
- Corporate information
- Mine address
- General information
- Production, ventilation, and drainage data
- Energy and environmental value of emission reductions
- Power generation potential
- Pipeline sales potential
- Other utilization possibilities

The mine profiles are ordered alphabetically by state, and arranged by mine name. Following this chapter are summary tables that list key data elements shown in the mine profiles. Summary Table 1 lists all profiled mines in alphabetical order. The individual mine profiles follow the summary tables.

Mine Status

Each mine's operating status as of December 2006 is listed at the top left-hand corner of each profile. The operating status may be listed as described below:

<u>Active</u>: These mines are currently producing coal.

<u>Idle</u>: A mine that is open but not currently producing coal.

The current operating status was determined by reviewing coal industry publications that track the production status of coal mines, and through discussions with MSHA district offices and sources in the coal industry. Only mines active in 2006 are included in this report.

Drainage System

The presence of a drainage system is indicated at the top left-hand corner of each profile below Mine Status. If a drainage system is used at the mine, “Yes” appears in the Drainage System field.

Use Project

If a mine recovers (captures) and uses methane, the type of utilization project is designated in this field. Use projects include: pipeline injection, electric power, and heaters. If there is currently no use project at the mine, "none" appears in the field.

2006 Rank

This field shows each mine's rank based on 2006 methane emissions from ventilation systems. This is the criterion used to rank gassy underground mines in this report.

Geographic Data

The first section of each profile gives the geographic location of the mine, including the state, county, coal basin where the mine is located, and the coalbed(s) from which it produces coal. The sources for this information were MSHA (2007) and the Keystone Coal Industry Manual (Keystone, 2007).

<u>State</u>: Mines included in this report are located in the following states - Alabama, Colorado, Illinois, Indiana, Kentucky, New Mexico, Ohio, Oklahoma, Pennsylvania, Utah, Virginia, or West Virginia. Summary Table 2 shows the mines listed by state.

<u>County</u>: A relatively small number of counties contain a majority of the gassy mines in the entire U.S. Summary Table 2 shows the mines listed by state and by county.

<u>Coal Basin</u>: Mines are located in one of the major coal producing regions: the Arkoma Basin, Black Warrior Basin, the Central Appalachian Basin, the Northern Appalachian Basin, the Illinois Basin, or one of the "Western basins" (Central Rockies, San Juan, or Uinta Basin), which are located in the states of Colorado, Utah, and New Mexico. Major geological characteristics of coal seams, including methane content, sulfur content, depth, and permeability tend to vary by basin. Summary Table 3 lists the mines by basin and 2006 estimated specific emissions per ton of coal mined for each listed mine.

<u>Coalbed</u>: Substantial and detailed information has been published on the geological and mining characteristics of major coalbeds occurring in the United States. Summary Table 4 lists mines according to the seam from which they produce their coal.

Corporate Information

<u>Current Operator</u>: Current operator refers to the mining company that operates the mine. Summary Table 5 lists mines by mining company. The sources for this information were the MSHA database (MSHA, 2007) and the Keystone Coal Industry Manual (Keystone, 2007).

<u>Owner/Parent Company</u>: Many coal mines are owned by a parent company. In addition to showing the coal companies, Summary Table 5 also shows the parent corporation of the mining company. This information was taken from MSHA (2007) and Keystone (2007).

<u>Previous Owner(s)</u>: The names of previous mine owners are useful as some of the coal mines profiled here have had numerous owners. This information, along with the previous or alternate name of the mine, is based on previous editions of the Keystone Coal Industry Manual and the MSHA database (MSHA, 2007).

Previous or Alternate Name: Mines frequently undergo name changes, particularly when they are purchased by a new company. This section lists previous or alternate mine names.

Mine Address

This section includes the phone number and mailing address of the mine and a contact name. The principal source of this information was the Keystone Coal Industry Manual. The information in this section is believed to be current. If contact information was not available in the Keystone Coal Industry Manual, contact information from the Energy Information Administration's (EIA) Coal Production Data Files for the year 2006 was used (EIA, 2006).

General Information

Number of Employees: This field shows the number of people employed by the mine, as reported in the Keystone Coal Industry Manual. If employment information was not listed in the Keystone Coal Industry Manual, the MSHA Data Retrieval System was consulted and the average number of employees for the most recent quarter was used.

Year of Initial Production: Year of initial production indicates the age of the mine, as reported in the Keystone Coal Industry Manual.

Life Expectancy: Life expectancy refers to the number of years left in the mine's plan for mining coal; it can be an important factor in determining whether a mine is a good candidate for a methane recovery and use project. Information on life expectancy was collected from various Keystone Coal Industry Manuals. However, given the difficulty in predicting mine life this statistic is perhaps only marginally useful, and care should be exercised in basing decisions on this factor.

Prep Plant Located on Site: The profile indicates whether a preparation plant is located at the mine, based on the Keystone Coal Industry Manual's and *Coal Age* magazine's annual prep plant surveys. At the preparation plant, coal is crushed, cleaned, and dried. Most large mines have a prep plant located within close proximity. In some cases, a prep plant will process coal not only from the on-site mine, but also from other nearby mines. Information regarding whether the mine has a prep plant, and the amount of coal processed, is important in determining the mine's total electricity and fuel demands.

Mining Method: Mines are classified as longwall or continuous (room-and-pillar), based on *Coal Age* magazine's annual longwall survey and on information in coal industry publications. The mining method used is important for several reasons. First, longwall mines tend to emit more methane than do room-and-pillar mines, as the longwall technique tends to cause a more extensive collapse of, and relaxation of the methane-rich strata surrounding the coal seam. Furthermore, longwall mining has higher up-front capital costs. Thus, a company is not likely to invest in a longwall at a mine that is not expected to have a fairly long life. Finally, while continuous mining is the more common method, the number of longwall mines is growing. In fact, the longwall technique seems to be the preferred mining method at the largest and gassiest mines. It is important to note that a typical longwall mine uses 80% longwall mining and 20% continuous mining. All mines not listed on the *Coal Age* longwall survey were assumed to be continuous. Summary Table 6 lists mines by mining method.

Primary Coal Use: Coal may be used for steam and/or metallurgical purposes. Steam coal is used by utilities to produce electricity, while metallurgical coal is used to produce coke. The primary coal use is based on information in the Keystone Coal Industry Manual. Summary Table 7 lists mines by primary coal use.

Btus/lb: Btus (British Thermal Units) per pound of coal produced indicates the heating value of the coal. This statistic, which was taken from the Keystone Coal Industry Manual, is used in comparing the energy value of the coal to the energy value of the methane recovered (see section on Environmental and Energy benefits below). Heating values were not available for all mines. Where coal analysis for individual mines was not available, mean heating values for the basin/seam were used.

Production, Ventilation, and Drainage Data

This section presents the quantity of methane emitted from, and the amount of coal produced by the profiled mines for each of the years 2002 to 2006.

Coal Production: Most of the mines profiled in this report have production exceeding one million tons per year. Annual coal production is an important factor in determining a mine's potential for profitable methane recovery. Generally, larger mines will be better candidates because they will have potential for high methane production and they are more likely to be able to finance capital investments in methane recovery and utilization projects. Coal production is based primarily on annual Energy Information Administration (EIA) reports, but is supplemented with data from coal producing states. Summary Table 8 lists the coal mines by the amount of coal they produced in 2006.

Estimated Total Methane Liberated: Methane liberation is the total volume of methane that is removed from the mine by ventilation and drainage. Liberation differs from emissions in that the term emissions, as used in this report, refers to methane that is not used and is therefore emitted to the atmosphere. Estimated total methane liberated is the sum of "emissions from ventilation systems" and "estimated methane drained." For mines that do not use or sell any of their methane, estimated total methane liberated equals estimated methane emissions to the atmosphere. The volume of methane liberated is shown for the years 2002-2006. Summary Table 10 shows mines listed by their estimated total daily methane liberation for 2006.

Emissions from Ventilation Systems: Methane released to the atmosphere from ventilation systems is emitted in very low concentrations (typically less than 1% in air). MSHA field personnel test methane emissions rates at each coal mine on a quarterly basis. Testing is performed underground at the same location each time. However, MSHA does not necessarily conduct the tests at precise three-month intervals, nor are they always taken at the same time of day. The ventilation emissions data for a given year are therefore averages of the four quarterly tests, and are accurate to the extent that the data collected at those four times are representative of actual emissions. Summary Table 11 lists the mines by their 2006 ventilation emissions, based on MSHA data.

Estimated Methane Drained: Mines that employ degasification systems emit large quantities of methane in high concentrations. Summary Table 12 lists mines according to the estimated methane drained. In contrast to ventilation emissions, no agency requires mines to report the amount of methane they drain, and actual methane drainage data are therefore unavailable. Thus, EPA has estimated the volume of methane drained based on estimated drainage efficiency, as defined below. Based on information obtained from MSHA district offices, EPA has developed a list of 23 U.S. mines that have drainage systems in place. A list of the mines that have drainage systems is shown in Summary Table 9. For the purpose of estimating emissions from drainage systems, if a mine is listed as having a drainage system in place, it was assumed that the system was in place from 1993 onward, unless EPA has information otherwise.

Specific Emissions: "Specific emissions" refer to the total amount of methane liberated per ton of coal that is mined. Specific emissions are an important indicator of whether a mine is a good candidate for a methane recovery project. In general, mines with higher specific emissions tend to have stronger potential for methane recovery. Summary Table 13 shows a list of mines ordered according to specific emissions. Note that the coal production and methane liberation values shown in this report have been rounded, whereas the data actually used to calculate the specific emissions values have not been rounded. Therefore, the specific emissions data shown in this report may differ from results that the reader would obtain by dividing the methane liberation values by the coal production values. This difference is strictly due to rounding, and does not reflect any error in the calculation of methane liberated.

Methane Used: Methane used refers to the total amount of drained methane that was put to productive use (e.g., natural gas pipeline injection, fuel for onsite power generation, etc.). Methane used does not always equal methane drained as some mines vent the methane liberated from degasification systems to the atmosphere. Table 14 shows a list of mines employing methane use projects.

Estimated Current Drainage Efficiency: In order to estimate the amount of methane emitted at mines that are believed to have drainage systems, it was assumed that these emissions would represent from 20-60% of total methane liberated from the mine. Thus, for mines that have drainage systems, ventilation emissions were assumed to equal 40-80% of total liberation, with emissions from drainage systems accounting for the remaining 20-60%. For mines that do not already have drainage systems in place, ventilation emissions are assumed to equal 100% of total methane liberation.

The assumption that methane drainage accounts for 40% of total methane liberation is probably conservative for some mines, but optimistic for others. Therefore, drainage estimates of 20, 40, and 60% were calculated for each mine profile. Accordingly, the assumed drainage efficiency of 40% may not reflect actual conditions at any one mine.

Estimated Current Market Penetration: In order to estimate the market penetration of CMM utilization, this field represents the percentage of drained methane that is used rather than vented to the atmosphere. Mines already draining methane that do not fully utilize, or do not utilize at all, the methane drained represent potential CMM project opportunities.

Drainage System Used: Twenty-three of the mines profiled in this report use some type of drainage (or degasification) system to capture coal mine methane. Drainage systems used include vertical pre-mine (drilled in advance of mining), vertical gob wells, long-hole horizontal pre-mine, and horizontal pre-mine. Summary Table 9 lists mines by drainage system used.

Energy and Environmental Value of Emissions Reduction

This section presents information on the environmental and energy benefits that may be achieved by developing a methane recovery project at a mine.

CO_2 Equivalent of CH_4 Emissions Reductions ($MMTCO_2e/yr$). This statistic shows the carbon dioxide (CO_2) equivalent of the annual methane emissions reductions that may potentially be achieved at each mine. The CO_2 equivalent of the potential methane emissions reductions is shown in order to facilitate the comparison of the environmental benefits of coal mine methane recovery and use projects to other greenhouse gas mitigation projects. The potential quantity of methane that may be recovered and used by a mine – which represents the emissions reductions that may be achieved – is converted to a CO_2 equivalent as follows:

CO_2 equivalent
(million tons/yr) = [CH_4 liberated (mmcf/yr) x recovery efficiency (20%, 40% and 60%) x 19.2 g CH_4/cf x 21 g CO_2/ 1 g CH_4 x 1 lb / 453.59 g x 1 ton / 2000 lbs]

where: 21 is the global warming potential (GWP) of emitting 1 gram of methane compared to emitting 1 gram of carbon dioxide over a 100 year time period[16]

19.2 g/cf is the density of methane at 60 degrees F and atmospheric pressure

The CO_2 equivalents are shown assuming a 20%, 40% and 60% recovery efficiency (i.e., the portion of total methane liberated that is recovered and utilized). Summary Table 15 shows the CO_2 equivalent of the potential methane emissions reductions that may be achieved at each mine.

<u>CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion</u>: This ratio shows the reduction in CO_2 emissions from the combustion of methane instead of coal produced at the mine. The ratio is calculated by converting the methane recovered into a CO_2 equivalent (as described above) and dividing by the annual CO_2 emitted from the combustion of coal produced at the mine. In order to calculate the CO_2 emissions from coal combustion, the annual coal production is multiplied by the Btu value of the coal (see general information section for Btu value). Next, this value is multiplied by an emissions factor of from 203 to 210 lbs CO_2 per million Btu.[17] Finally, the value is multiplied by 99% to account for the fraction oxidized. The formula is as follows:

[CO_2 equivalent of potential annual CH_4 emissions reductions (lbs)] / [annual coal production (tons) x Btus/ton x lbs CO_2 emitted / Btu x 99% (fraction oxidized)].

The ratio is calculated assuming 20%, 40% and 60% recovery efficiencies.

<u>Btu Value of Recovered Methane/Btu Value of Coal Produced</u>: In order to calculate this ratio, the potential annual quantity of methane recovered is multiplied by a value of 1000 Btus/cf. Annual coal production is multiplied by the Btus/ton value for the mine. The ratio of the energy value of the methane recovered to the energy value of the coal produced is then calculated. The formula is as follows:

[Recovered methane (cf/yr) x 1000 Btus/cf] / [coal production (tons) x Btus/ton]

As with the other statistics in this section, the ratio is calculated assuming a 20%, 40% and 60% recovery efficiency. In comparison with the first ratio (CO_2 equivalent of methane/ CO_2 emissions from coal combustion), the energy value of the methane emissions is a much smaller fraction of the energy value of the coal production.

[16] For further information on the global warming potential of various greenhouse gases see Intergovernmental Panel on Climate Change (2006).
[17] The emissions factor used is based on average state values reported in Energy Information Administration (1992). For the states examined in this report, values range from about 203 to 210 lbs CO_2/mm Btu.

Power Generation Potential

This section presents data relevant to the examination of whether the mine is a good candidate for an on-site electricity generation project.

Utility Electricity Supplier: The utility that supplies electricity to the mine is listed here, based on the service areas reported in the *U.S. Electric Power System: CD-ROM 2007/2008 Edition* (Platts, 2007). Summary Table 16 lists the utilities that sell power to the profiled mines.

Parent of Utility: The parent company of the local electric utility is also shown. This information is also based on the *U.S. Electric Power System: CD-ROM 2007/2008 Edition* (Platts, 2007).

Transmission Line in County: The presence of a transmission line is also shown. This information is also based on the *U.S. Electric Power System: CD-ROM 2007/2008 Edition* (Platts, 2007).

Total Electricity Demand (MW): The annual electricity demand – including the electricity demands of the mine plus the additional electricity load of the preparation plant – is calculated as follows:

Mine Electricity Demand Assumptions:

- Total annual electricity needs are estimated by assuming that 24 kWh are needed for each ton of coal mined.
- Ventilation systems are run 24 hours a day, 365 days a year (8760 hours a year) and account for about 25% of total electricity needs.
- Other mine operations run 16 hours a day for 220 days a year (3520 hours a year) and account for 75% of total electricity needs.

Demand (kWh/yr): 24 kWh/ton x tons mined/yr = kWhs/yr
Demand (kW): [(75% x kWhs/yr)/(3520 hours)] + [(25% x kWhs/yr)/8760 hours)]
(mine operations) + *(mine ventilation)*

Prep Plant Electricity Demand Assumptions:

Prep plants require 6 kWh/ton of coal processed
Prep plants are operated 16 hours a day, 220 days a year (3520 hours)
Demand (kWh/yr): 6 kWh/ton x tons/year
Demand (kW): [kWh/yr / 3520 hours]

Electricity Demand (GWh/year): The annual continuous electricity demand – including the electricity demands of the mine plus the additional electricity load of the preparation plant – is calculated as follows:

Mine Electricity Demand Assumptions:

Total annual electricity needs are estimated by assuming that 24 kWh are needed for each ton of coal mined.

Demand (kWh/yr): 24 kWh/ton x tons mined/yr = kWhs/yr

Demand (GWh/year): [Demand (kWh/yr)]/ 10^6

Prep Plant Electricity Demand Assumptions:

Prep plants require 6 kWh/ton of coal processed

Demand (kWh/yr): 6 kWh/ton x tons/year

Demand (GWh/year): [Demand (kWh/yr)]/ 10^6

Potential Electric Generating Capacity (kW): The potential electric generating capacity (i.e., the amount of electricity that could be generated from recovered coal mine methane) is estimated by assuming that there are 1000 Btus/cf of methane recovered and that the heat rate of a generator would be about 11,000 Btu/kWh, which is a conservative assumption for a heat rate given that a gas turbine would likely be used for such a project (Other technologies such as internal combustion engines may also be used to generate electricity). The capacity is estimated based on 20%, 40%, and 60% recovery efficiencies (i.e. portion of total methane liberated that is recovered and utilized). The formula is:

Generating Capacity (kW): CH_4 liberated in cf/day x 1 day/24 hours x 1000 Btus/cf x kWh/11,000 Btus.

Summary Table 17 lists the mines according to their potential electric generating capacity in MW.

Pipeline Potential

This section presents data that are useful in determining whether a mine is a good candidate for a pipeline sales project. Data for this section was taken from the *Homeland Security Infrastructure Program (HSIP) Gold Database* (NGA, 2007).

Potential Annual Gas Sales: Potential annual gas sales are estimated by multiplying total daily methane liberated by 365 days per year and then multiplying that value by the assumed recovery efficiency. Potential annual gas sales are calculated for 20%, 40%, and a 60% assumed recovery efficiencies and are presented in billion cubic feet. The estimated amount of gas that could be produced for sale to a pipeline at each candidate mine is shown in Summary Table 18.

Description of Surrounding Terrain: The terrain surrounding the mine is described, as this is an important factor in determining the costs of laying gathering lines for the project. While many mines in Appalachia are located in hilly or mountainous terrain, mines in the Illinois Basin tend to be located on relatively flat plains.

Transmission Pipeline in County: A "yes" indicates that an existing commercial pipeline runs through the county.

Owner of Nearest Pipeline: The corporate owner of the pipeline located closest to the mine is provided.

Distance to Pipeline: A measure of the distance between the mine and the nearest pipeline as determined in NGA (2007). Some western coal mines may be more than 20 miles from the nearest pipeline. In contrast, most eastern coal mines are located within ten miles of a commercial pipeline. However, while a mine may be located within close proximity to an existing gas pipeline, there are no guarantees that the pipeline will have enough capacity to take the gas produced from a coal mine. In particular, the Appalachian region tends to have limited pipeline capacity.

Pipeline Diameter: The diameter (in inches) of the nearest pipeline is provided.

Other Utilization Possibilities

This section addresses the possibility of using methane in a nearby coal-fired power plant.

Name of Nearby Coal Fired Power Plant: A few of the mines profiled here are located near a coal-fired power plant. For these mines, the name of the nearby power plant is listed. The source of this information, along with the estimated distance to the power plant and the plant capacity is taken from the *U.S. Electric Power System: CD-ROM 2007/2008 Edition* (Platts, 2007).

Distance to Plant: The profile shows the estimated distance between the mine and the nearby power plant.

Other Nearby Industrial/Institutional Facilities: This section describes nearby industrial and institutional facilities, which may represent potential users of recovered methane.

5. Mine Summary Tables

List of Summary Tables:

Table 1: Mines Listed Alphabetically

Mine Name	State	Mine Name	State
Aberdeen	UT	Jones Fork E-3	KY
American Eagle Mine	WV	Justice #1	WV
Bailey Mine	PA	Loveridge No. 22	WV
Beckley Crystal	WV	Mc Clane Canyon Mine	CO
Blacksville No. 2	WV	Mc Elroy Mine	WV
Blue Creek No. 4	AL	Miles Branch Mine	VA
Blue Creek No. 5	AL	Mine No. 2	KY
Blue Creek No. 7	AL	No. 2	VA
Bowie No. 2	CO	No. 3 Mine	KY
Buchanan Mine	VA	North River Mine	AL
Century Mine	OH	Oak Grove Mine	AL
Cumberland	PA	Pattiki Mine	IL
Dakota No. 2	WV	Pinnacle	WV
Deep Mine #26	VA	Powhatan No. 6 Mine	OH
Dotiki Mine	KY	Robinson Run No. 95	WV
Dugout Canyon	UT	San Juan South	NM
E3-1	KY	Shoal Creek	AL
Eagle Mine	WV	Shoemaker	WV
Eighty-Four Mine	PA	South Central Mine	OK
Elk Creek Mine	CO	VP 8	VA
Emerald	PA	Wabash	IL
Enlow Fork Mine	PA	West Elk Mine	CO
Federal No. 2	WV	West Ridge Mine	UT
Galatia	IL	Whitetail Kittanning Mine	WV
Gibson	IN	Willow Lake Portal	IL

Table 2: Mines Listed by State and County

Mine Name	State	County	Name	State	County
Oak Grove Mine	AL	Jefferson	Cumberland	PA	Greene
Shoal Creek	AL	Jefferson	Emerald	PA	Greene
Blue Creek No. 4	AL	Tuscaloosa	Enlow Fork Mine	PA	Greene
Blue Creek No. 5	AL	Tuscaloosa	Eighty-Four Mine	PA	Washington
Blue Creek No. 7	AL	Tuscaloosa	Aberdeen	UT	Carbon
North River Mine	AL	Tuscaloosa	Dugout Canyon	UT	Carbon
Bowie No. 2	CO	Delta	West Ridge Mine	UT	Carbon
Mc Clane Canyon Mine	CO	Garfield	Buchanan Mine	VA	Buchanan
Elk Creek Mine	CO	Gunnison	VP 8	VA	Buchanan
West Elk Mine	CO	Gunnison	No. 2	VA	Dickenson
Galatia	IL	Saline	Miles Branch Mine	VA	Tazewell
Willow Lake Portal	IL	Saline	Deep Mine #26	VA	Wise
Wabash	IL	Wabash	Dakota No. 2	WV	Boone
Pattiki Mine	IL	White	Justice #1	WV	Boone
Gibson	IN	Gibson	Robinson Run No. 95	WV	Harrison
Dotiki Mine	KY	Hopkins	American Eagle Mine	WV	Kanawha
Jones Fork E-3	KY	Knott	Eagle Mine	WV	Kanawha
Mine No. 2	KY	Martin	Loveridge No. 22	WV	Marion
E3-1	KY	Perry	Mc Elroy Mine	WV	Marshall
No. 3 Mine	KY	Pike	Shoemaker	WV	Marshall
San Juan South	NM	San Juan	Blacksville No. 2	WV	Monongalia
Century Mine	OH	Belmont	Federal No. 2	WV	Monongalia
Powhatan No. 6 Mine	OH	Belmont	Whitetail Kittanning Mine	WV	Preston
South Central Mine	OK	Le Flore	Beckley Crystal	WV	Raleigh
Bailey Mine	PA	Greene	Pinnacle	WV	Wyoming

Table 3: Mines Listed by Coal Basin

Coal Basin/ Mine Name	Estimated Specific Emissions (CF/Ton)
Arkoma	
South Central Mine	735
Black Warrior	
Blue Creek No. 4	3,874
Blue Creek No. 5	4,271
Blue Creek No. 7	4,510
North River Mine	648
Oak Grove Mine	1,922
Shoal Creek	2,075
Central Appalachian	
American Eagle Mine	753
Beckley Crystal	2,185
Buchanan Mine	5,270
Dakota No. 2	601
Deep Mine #26	672
E3-1	298
Eagle Mine	350
Jones Fork E-3	221
Miles Branch Mine	1,393
Mine No. 2	457
No. 2	1,498
No. 3 Mine	262
Pinnacle	1,785
VP 8	24,295*
Central Rockies	
Bowie No. 2	161
Illinois	
Dotiki Mine	71
Galatia	429
Gibson	313
Pattiki Mine	297
Wabash	639

Coal Basin/ Mine Name	Estimated Specific Emissions (CF/Ton)
Willow Lake Portal	102
Northern Appalachian	
Bailey Mine	383
Blacksville No. 2	701
Century Mine	105
Cumberland	491
Eighty-Four Mine	532
Emerald	458
Enlow Fork Mine	344
Federal No. 2	531
Justice #1	363
Loveridge No. 22	406
Mc Elroy Mine	525
Powhatan No. 6 Mine	167
Robinson Run No. 95	361
Shoemaker	1,159
Whitetail Kittanning Mine	366
San Juan	
San Juan South	340
Uinta	
Aberdeen	1,202
Dugout Canyon	141
Elk Creek Mine	530
Mc Clane Canyon Mine	1,300
West Elk Mine	1,107
West Ridge Mine	430

* CONSOL Energy's VP 8 mine in Virginia had specific emissions of 24,295 cf/ton based on total methane liberated in 2006. However, the mine was shut down in spring 2006 but gas recovery continued, leading to elevated methane liberated per ton of coal produced. Based on first quarter coal production - the last full quarter of production - of 0.259 million short tons and quarterly methane liberation of 1,734 mmcf, specific emissions for the last full quarter of operation were 6,695 cf/ton.

Table 4: Mines Listed by Coalbed

Mine Name	Coalbed	Mine Name	Coalbed
West Elk Mine	B Seam	Bailey Mine	Pittsburgh No. 8
Bowie No. 2	B&D Seams	Cumberland	Pittsburgh No. 8
Blue Creek No. 5	Blue Creek	Emerald	Pittsburgh No. 8
Oak Grove Mine	Blue Creek	Enlow Fork Mine	Pittsburgh No. 8
Blue Creek No. 4	Blue Creek / Mary Lee	Eighty-Four Mine	Pittsburgh No. 8
Blue Creek No. 7	Blue Creek / Mary Lee	Blacksville No. 2	Pittsburgh No. 8
Shoal Creek	Blue Creek / Mary Lee	Federal No. 2	Pittsburgh No. 8
Mc Clane Canyon Mine	Cameo Seam	Loveridge No. 22	Pittsburgh No. 8
Elk Creek Mine	D-seam	Mc Elroy Mine	Pittsburgh No. 8
American Eagle Mine	Eagle / Big Eagle	Shoemaker	Pittsburgh No. 8
Eagle Mine	Eagle / Big Eagle	Century Mine	Pittsburgh No. 8
Dugout Canyon	Gilson / Rock Canyon	Dakota No. 2	Pittsburgh No. 8
South Central Mine	Hartshorne	Miles Branch Mine	Pocahontas 5
E3-1	Hazard 4 / Elkhorn 3	Buchanan Mine	Pocahontas No. 3
Jones Fork E-3	Hazard 4 / Elkhorn 3	No. 2	Pocahontas No. 3
Pattiki Mine	Herrin No. 6	VP 8	Pocahontas No. 3
Willow Lake Portal	Illinois No. 5 & 6	Pinnacle	Pocahontas No. 3
Whitetail Kittanning Mine	Kittanning	Mine No. 2	Pond Creek
Aberdeen	L. Sunnyside / Gilson / Aber.	No. 3 Mine	Pond Creek / Van Lear
Deep Mine #26	Lower Banner	Justice #1	Powellton / Buffalo Crk
West Ridge Mine	Lower Sunnyside	North River Mine	Pratt
Beckley Crystal	NA	Galatia	Springfield No. 5
San Juan South	No. 9 / No. 8	Gibson	Springfield No. 5
Robinson Run No. 95	Pittsburgh No. 8	Wabash	Springfield No. 5
Powhatan No. 6 Mine	Pittsburgh No. 8	Dotiki Mine	W. KY No. 9

Table 5: Mines Listed by Company

Owner/Parent	Operator	Mine Name
Alliance Resource Partners LP		
	Excel Mining LLC	Mine No. 2
	Excel Mining LLC	No. 3 Mine
	Gibson County Coal LLC	Gibson
	Webster County Coal LLC	Dotiki Mine
	White County Coal LLC	Pattiki Mine
Alpha Natural Resources LLC		
	Black Dog Coal Corporation	No. 2
	Kingwood Mining Company LLC	Whitetail Kittanning Mine
	Paramount Coal Company Virginia LLC	Deep Mine #26
Arch Coal Inc		
	Canyon Fuel Company LLC	Dugout Canyon
	Mountain Coal Company	West Elk Mine
Baylor Mining Inc		
	Baylor Mining Inc	Beckley Crystal
BHP Billiton		
	San Juan Coal Company	San Juan South
Chevron Corporation		
	Chevron Mining Inc	North River Mine
Cleveland-Cliffs Inc		
	Oak Grove Resources LLC	Oak Grove Mine
	Pinnacle Mining Company LLC	Pinnacle
CONSOL Energy Inc		
	Consol of Kentucky Inc	Jones Fork E-3
	Consol Pennsylvania Coal Company	Bailey Mine
	Consol Pennsylvania Coal Company	Enlow Fork Mine
	Consolidation Coal Company	Blacksville No. 2
	Consolidation Coal Company	Buchanan Mine
	Consolidation Coal Company	Loveridge No. 22
	Consolidation Coal Company	Miles Branch Mine
	Consolidation Coal Company	Robinson Run No. 95
	Consolidation Coal Company	Shoemaker
	Eighty-Four Mining Company	Eighty-Four Mine
	Island Creek Coal Company	VP 8
	McElroy Coal Company	Mc Elroy Mine
Drummond Company Inc		
	Drummond Company Inc	Shoal Creek
Foundation Coal Corporation		
	Cumberland Coal Resources LP	Cumberland
	Emerald Coal Resources LP	Emerald
	Wabash Mine Holding Company	Wabash

Table 5: Mines Listed by Company, Cont'd.

Owner/Parent	Operator	Mine Name
Magnum Coal Company		
	Dakota LLC	Dakota No. 2
Massey Energy Company		
	Independence Coal Company Inc	Justice #1
Murray Energy Corp		
	American Energy Corporation	Century Mine
	Ohio Valley Coal Company	Powhatan No. 6 Mine
	The American Coal Company	Galatia
	Utah American Energy Inc	Aberdeen
	Utah American Energy Inc	West Ridge Mine
Newtown Energy Inc		
	Newtown Energy Inc	Eagle Mine
Oxbow Carbon & Materials Inc		
	Oxbow Mining LLC	Elk Creek Mine
Patriot Coal Corporation		
	Eastern Associated Coal LLC	Federal No. 2
Peabody Energy Corp		
	Big Ridge Inc	Willow Lake Portal
South Central Coal Company Inc		
	South Central Coal Company Inc	South Central Mine
Speed Mining Inc		
	Speed Mining Inc	American Eagle Mine
Teco Coal Co		
	Perry County Coal Corp	E3-1
Union Pacific		
	Bowie Resources LLC	Bowie No. 2
Walter Industries Inc		
	Jim Walter Resources Inc	Blue Creek No. 4
	Jim Walter Resources Inc	Blue Creek No. 5
	Jim Walter Resources Inc	Blue Creek No. 7
Wexford Capital LLC		
	McClane Canyon Mining LLC	Mc Clane Canyon Mine

Table 6: Mines Listed by Mining Method

Mine Name	Method	Mine Name	Method
American Eagle Mine	Continuous	Bowie No. 2	Longwall
Beckley Crystal	Continuous	Buchanan Mine	Longwall
Dakota No. 2	Continuous	Century Mine	Longwall
Deep Mine #26	Continuous	Cumberland	Longwall
Dotiki Mine	Continuous	Dugout Canyon	Longwall
E3-1	Continuous	Eighty-Four Mine	Longwall
Eagle Mine	Continuous	Elk Creek Mine	Longwall
Gibson	Continuous	Emerald	Longwall
Jones Fork E-3	Continuous	Enlow Fork Mine	Longwall
Mc Clane Canyon Mine	Continuous	Federal No. 2	Longwall
Miles Branch Mine	Continuous	Galatia	Longwall
Mine No. 2	Continuous	Justice #1	Longwall
No. 2	Continuous	Loveridge No. 22	Longwall
No. 3 Mine	Continuous	Mc Elroy Mine	Longwall
Pattiki Mine	Continuous	North River Mine	Longwall
South Central Mine	Continuous	Oak Grove Mine	Longwall
Wabash	Continuous	Pinnacle	Longwall
Whitetail Kittanning Mine	Continuous	Powhatan No. 6 Mine	Longwall
Willow Lake Portal	Continuous	Robinson Run No. 95	Longwall
Aberdeen	Longwall	San Juan South	Longwall
Bailey Mine	Longwall	Shoal Creek	Longwall
Blacksville No. 2	Longwall	Shoemaker	Longwall
Blue Creek No. 4	Longwall	VP 8	Longwall
Blue Creek No. 5	Longwall	West Elk Mine	Longwall
Blue Creek No. 7	Longwall	West Ridge Mine	Longwall

Table 7: Mines Listed by Primary Coal Use

Mine Name	Primary Use	Mine Name	Primary Use
Blue Creek No. 4	Metallurgical	No. 3 Mine	Steam
Blue Creek No. 7	Metallurgical	Pattiki Mine	Steam
Miles Branch Mine	Metallurgical	Powhatan No. 6 Mine	Steam
Pinnacle	Metallurgical	Robinson Run No. 95	Steam
Aberdeen	Steam	San Juan South	Steam
Beckley Crystal	Steam	Shoal Creek	Steam
Blacksville No. 2	Steam	Shoemaker	Steam
Bowie No. 2	Steam	South Central Mine	Steam
Century Mine	Steam	Wabash	Steam
Cumberland	Steam	West Elk Mine	Steam
Dakota No. 2	Steam	West Ridge Mine	Steam
Dotiki Mine	Steam	Whitetail Kittanning Mine	Steam
Dugout Canyon	Steam	Willow Lake Portal	Steam
E3-1	Steam	American Eagle Mine	Steam, Metallurgical
Eagle Mine	Steam	Bailey Mine	Steam, Metallurgical
Elk Creek Mine	Steam	Blue Creek No. 5	Steam, Metallurgical
Enlow Fork Mine	Steam	Buchanan Mine	Steam, Metallurgical
Federal No. 2	Steam	Deep Mine #26	Steam, Metallurgical
Galatia	Steam	Eighty-Four Mine	Steam, Metallurgical
Gibson	Steam	Emerald	Steam, Metallurgical
Jones Fork E-3	Steam	Justice #1	Steam, Metallurgical
Loveridge No. 22	Steam	No. 2	Steam, Metallurgical
Mc Clane Canyon Mine	Steam	North River Mine	Steam, Metallurgical
Mc Elroy Mine	Steam	Oak Grove Mine	Steam, Metallurgical
Mine No. 2	Steam	VP 8	Steam, Metallurgical

Table 8: Mines Listed by 2006 Coal Production

Mine Name	MM Tons	Mine Name	MM Tons
Enlow Fork Mine	10.7	Pattiki Mine	2.5
Mc Elroy Mine	10.5	American Eagle Mine	2.4
Bailey Mine	10.2	Blue Creek No. 4	2.2
Cumberland	7.5	Aberdeen	2.1
Galatia	7.2	Pinnacle	2.0
San Juan South	7.0	Deep Mine #26	2.0
Century Mine	6.5	No. 3 Mine	1.9
Loveridge No. 22	6.4	Jones Fork E-3	1.8
West Elk Mine	6.0	Oak Grove Mine	1.4
Emerald	5.9	Whitetail Kittanning Mine	1.4
Robinson Run No. 95	5.7	Eagle Mine	1.3
Elk Creek Mine	5.1	Wabash	1.2
Blacksville No. 2	5.0	E3-1	1.1
Buchanan Mine	5.0	Shoemaker	1.0
Dotiki Mine	4.7	Justice #1	0.9
Federal No. 2	4.6	Mine No. 2	0.8
Bowie No. 2	4.4	Shoal Creek	0.8
Dugout Canyon	4.4	Blue Creek No. 5	0.8
Powhatan No. 6 Mine	4.4	Dakota No. 2	0.6
Willow Lake Portal	3.6	South Central Mine	0.4
Gibson	3.6	Beckley Crystal	0.3
Eighty-Four Mine	3.5	Miles Branch Mine	0.3
West Ridge Mine	3.0	VP 8	0.3
North River Mine	2.8	Mc Clane Canyon Mine	0.3
Blue Creek No. 7	2.6	No. 2	0.2

Table 9: Mines Employing Methane Drainage Systems

Mine Name	Type of Drainage System	Estimated Current Drainage Efficiency
Aberdeen	Vertical Gob Boreholes with Pumps	25%
American Eagle Mine	Vertical Gob Boreholes	40%
Bailey Mine	Vertical Gob Boreholes with Pumps	30%
Blacksville No. 2	Vertical Gob Boreholes with Pumps	25%
Blue Creek No. 4	Vertical Gob Boreholes; Horizontal Pre-Mine Boreholes; Vertical Pre-Mine Boreholes	73%
Blue Creek No. 5	Vertical Gob Boreholes; Horizontal Pre-Mine Boreholes; Vertical Pre-Mine Boreholes	73%
Blue Creek No. 7	Vertical Gob Boreholes; Horizontal Pre-Mine Boreholes; Vertical Pre-Mine Boreholes	73%
Bowie No. 2	Vertical Gob Boreholes with Pumps	25%
Buchanan Mine	Vertical Gob Boreholes; Horizontal Pre-Mine Boreholes; Vertical Pre-Mine Boreholes	88%
Cumberland	Vertical Gob Boreholes with Pumps	34%
Dugout Canyon	Vertical Gob Boreholes with Pumps	25%
Elk Creek Mine	Vertical Gob Boreholes with Pumps	25%
Emerald	Vertical Gob Boreholes with Pumps	30%
Federal No. 2	Vertical Gob Boreholes	15%
Loveridge No. 22	Vertical Gob Boreholes with Pumps	25%
Mc Elroy Mine	Vertical Gob Boreholes with Pumps	15%
Oak Grove Mine	Vertical Gob Boreholes; Horizontal Pre-Mine Boreholes; Vertical Pre-Mine Boreholes	10%
Pinnacle	Vertical Gob Boreholes; Horizontal Pre-Mine Boreholes	47%
Robinson Run No. 95	Vertical Gob Boreholes with Pumps	30%
San Juan South	Vertical Gob Boreholes; Horizontal Pre-Mine Boreholes	40%
Shoal Creek	Vertical Gob Boreholes with Pumps	3%
VP 8	Vertical Gob Boreholes; Horizontal Pre-Mine Boreholes; Vertical Pre-Mine Boreholes	83%
West Elk Mine	Horizontal & Vertical Gob Boreholes with Pumps	50%

Table 10: Mines Listed by Estimated Total Methane Liberated in 2006

Mine Name	MMCF/D	Mine Name	MMCF/D
Buchanan Mine	72.3	Deep Mine #26	3.7
Blue Creek No. 7	31.6	West Ridge Mine	3.6
Blue Creek No. 4	23.2	Gibson	3.1
VP 8	19.0	Shoemaker	3.1
West Elk Mine	18.2	Wabash	2.1
Mc Elroy Mine	15.1	Pattiki Mine	2.0
Bailey Mine	10.7	Beckley Crystal	2.0
Cumberland	10.1	Powhatan No. 6 Mine	2.0
Enlow Fork Mine	10.1	Bowie No. 2	2.0
Pinnacle	9.8	Century Mine	1.9
Blacksville No. 2	9.7	Dugout Canyon	1.7
Blue Creek No. 5	9.4	Whitetail Kittanning Mine	1.4
Galatia	8.5	No. 3 Mine	1.3
Oak Grove Mine	7.5	Eagle Mine	1.2
Elk Creek Mine	7.4	Miles Branch Mine	1.2
Emerald	7.4	Jones Fork E-3	1.1
Loveridge No. 22	7.1	Mine No. 2	1.1
Aberdeen	6.9	Willow Lake Portal	1.0
Federal No. 2	6.7	Dakota No. 2	1.0
San Juan South	6.5	Mc Clane Canyon Mine	0.9
Robinson Run No. 95	5.7	Justice #1	0.9
Eighty-Four Mine	5.1	Dotiki Mine	0.9
American Eagle Mine	5.0	South Central Mine	0.9
North River Mine	4.9	E3-1	0.9
Shoal Creek	4.7	No. 2	0.8

Table 11: Mines Listed by Daily Ventilation Emissions in 2006

Mine Name	MMCF/D	Mine Name	MMCF/D
Mc Elroy Mine	12.8	Gibson	3.1
Enlow Fork Mine	10.1	Shoemaker	3.1
West Elk Mine	9.1	American Eagle Mine	3.0
Blue Creek No. 7	8.7	Blue Creek No. 5	2.6
Galatia	8.5	Wabash	2.1
Buchanan Mine	8.4	Pattiki Mine	2.0
Bailey Mine	7.5	Beckley Crystal	2.0
Blacksville No. 2	7.2	Powhatan No. 6 Mine	2.0
Oak Grove Mine	6.7	Century Mine	1.9
Cumberland	6.7	Bowie No. 2	1.5
Blue Creek No. 4	6.4	Whitetail Kittanning Mine	1.4
Federal No. 2	5.7	No. 3 Mine	1.3
Elk Creek Mine	5.6	Dugout Canyon	1.3
Loveridge No. 22	5.3	Eagle Mine	1.2
Pinnacle	5.2	Miles Branch Mine	1.2
Emerald	5.2	Jones Fork E-3	1.1
Aberdeen	5.2	Mine No. 2	1.1
Eighty-Four Mine	5.1	Willow Lake Portal	1.0
North River Mine	4.9	Dakota No. 2	1.0
Shoal Creek	4.5	Mc Clane Canyon Mine	0.9
Robinson Run No. 95	4.0	Justice #1	0.9
San Juan South	3.9	Dotiki Mine	0.9
Deep Mine #26	3.7	South Central Mine	0.9
West Ridge Mine	3.6	E3-1	0.9
VP 8	3.2	No. 2	0.8

Table 12: Mines Listed by Estimated Daily Methane Drained in 2006

Mine Name	MMCF/D	Mine Name	MMCF/D
Buchanan Mine	63.9	Dakota No. 2	-
Blue Creek No. 7	22.9	Deep Mine #26	-
Blue Creek No. 4	16.8	Dotiki Mine	-
VP 8	15.8	E3-1	-
West Elk Mine	9.1	Eagle Mine	-
Blue Creek No. 5	6.8	Eighty-Four Mine	-
Pinnacle	4.6	Enlow Fork Mine	-
Cumberland	3.4	Galatia	-
Bailey Mine	3.2	Gibson	-
San Juan South	2.6	Jones Fork E-3	-
Blacksville No. 2	2.5	Justice #1	-
Mc Elroy Mine	2.3	Mc Clane Canyon Mine	-
Emerald	2.3	Miles Branch Mine	-
American Eagle Mine	2.0	Mine No. 2	-
Elk Creek Mine	1.9	No. 2	-
Loveridge No. 22	1.8	No. 3 Mine	-
Aberdeen	1.7	North River Mine	-
Robinson Run No. 95	1.7	Pattiki Mine	-
Federal No. 2	1.0	Powhatan No. 6 Mine	-
Oak Grove Mine	0.7	Shoemaker	-
Bowie No. 2	0.5	South Central Mine	-
Dugout Canyon	0.4	Wabash	-
Shoal Creek	0.1	West Ridge Mine	-
Beckley Crystal	-	Whitetail Kittanning Mine	-
Century Mine	-	Willow Lake Portal	-

Table 13: Mines Listed by Estimated Specific Emissions in 2006

Mine Name	CF/Ton	Mine Name	CF/Ton
VP 8	24,295*	Mc Elroy Mine	525
Buchanan Mine	5,270	Cumberland	491
Blue Creek No. 7	4,510	Emerald	458
Blue Creek No. 5	4,271	Mine No. 2	457
Blue Creek No. 4	3,874	West Ridge Mine	430
Beckley Crystal	2,185	Galatia	429
Shoal Creek	2,075	Loveridge No. 22	406
Oak Grove Mine	1,922	Bailey Mine	383
Pinnacle	1,785	Whitetail Kittanning Mine	366
No. 2	1,498	Justice #1	363
Miles Branch Mine	1,393	Robinson Run No. 95	361
Mc Clane Canyon Mine	1,300	Eagle Mine	350
Aberdeen	1,202	Enlow Fork Mine	344
Shoemaker	1,159	San Juan South	340
West Elk Mine	1,107	Gibson	313
American Eagle Mine	753	E3-1	298
South Central Mine	735	Pattiki Mine	297
Blacksville No. 2	701	No. 3 Mine	262
Deep Mine #26	672	Jones Fork E-3	221
North River Mine	648	Powhatan No. 6 Mine	167
Wabash	639	Bowie No. 2	161
Dakota No. 2	601	Dugout Canyon	141
Eighty-Four Mine	532	Century Mine	105
Federal No. 2	531	Willow Lake Portal	102
Elk Creek Mine	530	Dotiki Mine	71

* CONSOL Energy's VP 8 mine in Virginia had specific emissions of 24,295 cf/ton based on total methane liberated in 2006. However, the mine was shut down in spring 2006 but gas recovery continued, leading to elevated methane liberated per ton of coal produced. Based on first quarter coal production - the last full quarter of production - of 0.259 million short tons and quarterly methane liberation of 1,734 mmcf, specific emissions for the last full quarter of operation were 6,695 cf/ton.

Table 14: Mines Employing Methane Use Projects

Mine Name	Type of Use Project	Estimated Current Market Penetration
Blacksville No. 2	Pipeline	100%
Blue Creek No. 4	Pipeline	100%
Blue Creek No. 5	Pipeline	100%
Blue Creek No. 7	Pipeline	100%
Buchanan Mine	Pipeline	80%
Cumberland	Pipeline	100%
Emerald	Pipeline	100%
Federal No. 2	Elec Power	23%
Loveridge No. 22	Pipeline	100%
Oak Grove Mine	Pipeline	100%
Pinnacle	Pipeline	100%
Shoal Creek	Pipeline	100%
VP 8	Pipeline	80%
West Elk Mine	Heaters	5%

Table 15: Mines Listed by CO_2 Equivalent of Potential CH_4 Emissions Reductions

(Assuming 20% - 60% Recovery Efficiency)

Mine Name	MM Tons CO_2 /Yr		Mine Name	MM Tons CO_2 /Yr	
Buchanan Mine	2.34	7.03	Deep Mine #26	0.11	0.35
Blue Creek No. 7	1.02	3.07	West Ridge Mine	0.11	0.34
Blue Creek No. 4	0.75	2.25	Gibson	0.10	0.29
VP 8	0.61	1.85	Shoemaker	0.09	0.29
West Elk Mine	0.59	1.77	Wabash	0.06	0.20
Mc Elroy Mine	0.48	1.46	Pattiki Mine	0.06	0.19
Bailey Mine	0.34	1.03	Beckley Crystal	0.06	0.19
Cumberland	0.32	0.98	Powhatan No. 6 Mine	0.06	0.19
Enlow Fork Mine	0.32	0.98	Bowie No. 2	0.06	0.19
Pinnacle	0.31	0.95	Century Mine	0.06	0.18
Blacksville No. 2	0.31	0.94	Dugout Canyon	0.05	0.16
Blue Creek No. 5	0.30	0.91	Whitetail Kittanning Mine	0.04	0.13
Galatia	0.27	0.82	No. 3 Mine	0.04	0.13
Oak Grove Mine	0.24	0.72	Eagle Mine	0.04	0.12
Elk Creek Mine	0.24	0.72	Miles Branch Mine	0.03	0.11
Emerald	0.24	0.72	Jones Fork E-3	0.03	0.10
Loveridge No. 22	0.23	0.69	Mine No. 2	0.03	0.10
Aberdeen	0.22	0.67	Willow Lake Portal	0.03	0.09
Federal No. 2	0.21	0.65	Dakota No. 2	0.03	0.09
San Juan South	0.21	0.63	Mc Clane Canyon Mine	0.03	0.09
Robinson Run No. 95	0.18	0.55	Justice #1	0.03	0.09
Eighty-Four Mine	0.16	0.49	Dotiki Mine	0.03	0.08
American Eagle Mine	0.16	0.48	South Central Mine	0.02	0.08
North River Mine	0.15	0.47	E3-1	0.02	0.08
Shoal Creek	0.15	0.45	No. 2	0.02	0.08

Table 16: Mines Listed by Electric Utility Supplier

Utility Parent Company Mine Name	Utility Company
Allegheny Energy Inc	
Blacksville No. 2	Monongahela Power Co
Federal No. 2	Monongahela Power Co
Loveridge No. 22	Monongahela Power Co
Robinson Run No. 95	Monongahela Power Co
Whitetail Kittanning Mine	Monongahela Power Co
Bailey Mine	West Penn Power Co
Cumberland	West Penn Power Co
Eighty-Four Mine	West Penn Power Co
Emerald	West Penn Power Co
Enlow Fork Mine	West Penn Power Co
Ameren Corp	
Galatia	Central Illinois Public Services Co
American Electric Power Co Inc	
American Eagle Mine	Appalachian Power Co
Beckley Crystal	Appalachian Power Co
Buchanan Mine	Appalachian Power Co
Dakota No. 2	Appalachian Power Co
Deep Mine #26	Appalachian Power Co
Eagle Mine	Appalachian Power Co
Justice #1	Appalachian Power Co
Miles Branch Mine	Appalachian Power Co
No. 2	Appalachian Power Co
Pinnacle	Appalachian Power Co
VP 8	Appalachian Power Co
E3-1	Kentucky Power Co
Jones Fork E-3	Kentucky Power Co
Mine No. 2	Kentucky Power Co
No. 3 Mine	Kentucky Power Co
Mc Elroy Mine	Wheeling Power Co
Shoemaker	Wheeling Power Co

Table 16: Mines Listed by Electric Utility Supplier, Cont'd.

Utility Parent Company Mine Name	Utility Company
Berkshire Hathaway Inc	
Aberdeen	PacifiCorp
Dugout Canyon	PacifiCorp
West Ridge Mine	PacifiCorp
Duke Energy Corp	
Gibson	Duke Energy Indiana Inc
E.ON AG	
Dotiki Mine	Kentucky Utilities Co
NA	
San Juan South	Jemez Mountains Electric Coop Inc
Mc Clane Canyon Mine	None
Pattiki Mine	Wayne-White Counties Electric Coop
Wabash	Wayne-White Counties Electric Coop
OGE Energy Corp	
South Central Mine	Oklahoma Gas & Electric
Southern Co	
Blue Creek No. 4	Alabama Power Co
Blue Creek No. 5	Alabama Power Co
Blue Creek No. 7	Alabama Power Co
North River Mine	Alabama Power Co
Oak Grove Mine	Alabama Power Co
Shoal Creek	Alabama Power Co
Touchstone Energy Cooperatives	
Bowie No. 2	Delta-Montrose Electric Association
Elk Creek Mine	Delta-Montrose Electric Association
West Elk Mine	Delta-Montrose Electric Association
Century Mine	South Central Power Co
Powhatan No. 6 Mine	South Central Power Co
Willow Lake Portal	Southeastern Illinois Electric Coop Inc

Table 17: Mines Listed by Potential Electric Generating Capacity
(Assuming 20% - 60% Recovery Efficiency)

Mine Name	Megawatts	Mine Name	Megawatts
Buchanan Mine	54.8 - 164.4	Deep Mine #26	2.8 - 8.3
Blue Creek No. 7	23.9 - 71.8	West Ridge Mine	2.7 - 8.1
Blue Creek No. 4	17.6 - 52.8	Gibson	2.3 - 7.0
VP 8	14.4 - 43.3	Shoemaker	2.3 - 7.0
West Elk Mine	13.8 - 41.4	Wabash	1.6 - 4.7
Mc Elroy Mine	11.4 - 34.2	Pattiki Mine	1.5 - 4.6
Bailey Mine	8.1 - 24.2	Beckley Crystal	1.5 - 4.6
Cumberland	7.7 - 23.0	Powhatan No. 6 Mine	1.5 - 4.6
Enlow Fork Mine	7.6 - 22.9	Bowie No. 2	1.5 - 4.4
Pinnacle	7.5 - 22.4	Century Mine	1.4 - 4.2
Blacksville No. 2	7.3 - 22.0	Dugout Canyon	1.3 - 3.9
Blue Creek No. 5	7.1 - 21.4	Whitetail Kittanning Mine	1.0 - 3.1
Galatia	6.4 - 19.3	No. 3 Mine	1.0 - 3.1
Oak Grove Mine	5.6 - 16.9	Eagle Mine	0.9 - 2.8
Elk Creek Mine	5.6 - 16.9	Miles Branch Mine	0.9 - 2.7
Emerald	5.6 - 16.9	Jones Fork E-3	0.8 - 2.5
Loveridge No. 22	5.4 - 16.1	Mine No. 2	0.8 - 2.4
Aberdeen	5.2 - 15.6	Willow Lake Portal	0.8 - 2.3
Federal No. 2	5.1 - 15.3	Dakota No. 2	0.7 - 2.2
San Juan South	4.9 - 14.8	Mc Clane Canyon Mine	0.7 - 2.1
Robinson Run No. 95	4.3 - 12.9	Justice #1	0.7 - 2.1
Eighty-Four Mine	3.9 - 11.6	Dotiki Mine	0.7 - 2.1
American Eagle Mine	3.8 - 11.3	South Central Mine	0.7 - 2.1
North River Mine	3.7 - 11.1	E3-1	0.7 - 2.0
Shoal Creek	3.5 - 10.6	No. 2	0.6 - 1.9

Table 18: Mines Listed by Potential Annual Gas Sales *
(Assuming 20% - 60% Recovery Efficiency)

Mine Name	BCF/Yr	Mine Name	BCF/Yr
Buchanan Mine	5.3 - 1 5.8	Deep Mine #26	0.3 - 0.8
Blue Creek No. 7	2.3 - 6.9	West Ridge Mine	0.3 - 0.8
Blue Creek No. 4	1.7 - 5.1	Gibson	0.2 - 0.7
VP 8	1.4 - 4.2	Shoemaker	0.2 - 0.7
West Elk Mine	1.3 - 4.0	Wabash	0.2 - 0.5
Mc Elroy Mine	1.1 - 3.3	Pattiki Mine	0.1 - 0.4
Bailey Mine	0.8 - 2.3	Beckley Crystal	0.1 - 0.4
Cumberland	0.7 - 2.2	Powhatan No. 6 Mine	0.1 - 0.4
Enlow Fork Mine	0.7 - 2.2	Bowie No. 2	0.1 - 0.4
Pinnacle	0.7 - 2.2	Century Mine	0.1 - 0.4
Blacksville No. 2	0.7 - 2.1	Dugout Canyon	0.1 - 0.4
Blue Creek No. 5	0.7 - 2.1	Whitetail Kittanning Mine	0.1 - 0.3
Galatia	0.6 - 1.9	No. 3 Mine	0.1 - 0.3
Oak Grove Mine	0.5 - 1.6	Eagle Mine	0.1 - 0.3
Elk Creek Mine	0.5 - 1.6	Miles Branch Mine	0.1 - 0.3
Emerald	0.5 - 1.6	Jones Fork E-3	0.1 - 0.2
Loveridge No. 22	0.5 - 1.6	Mine No. 2	0.1 - 0.2
Aberdeen	0.5 - 1.5	Willow Lake Portal	0.1 - 0.2
Federal No. 2	0.5 - 1.5	Dakota No. 2	0.1 - 0.2
San Juan South	0.5 - 1.4	Mc Clane Canyon Mine	0.1 - 0.2
Robinson Run No. 95	0.4 - 1.2	Justice #1	0.1 - 0.2
Eighty-Four Mine	0.4 - 1.1	Dotiki Mine	0.1 - 0.2
American Eagle Mine	0.4 - 1.1	South Central Mine	0.1 - 0.2
North River Mine	0.4 - 1.1	E3-1	0.1 - 0.2
Shoal Creek	0.3 - 1.0	No. 2	0.1 - 0.2

* Mine's actual gas sales may differ from the potential

6. Profiled Mines (continued)

States with Candidate and Utilizing Mines:

Alabama

Colorado

Illinois

Indiana

Kentucky

New Mexico

Ohio

Oklahoma

Pennsylvania

Utah

Virginia

West Virginia

6. Profiled Mines

Data Summary

Below is a state-by-state summary of data pertaining to coal mine methane at the mines profiled in this report. Chapter 4 explains how these data were derived. Following this data summary section are individual mine profiles, in alphabetical order by state.

Alabama

Of the 14 profiled U.S. mines that already recover and use methane, five are located in Alabama. Three of these mines are owned by Walter Industries, one mine is owned by Cleveland-Cliffs, and one mine is owned by Drummond Company. All five mines sell methane to pipelines. Based on information obtained from MSHA (2007), these five mines recovered and sold an average of 47.5 mmcf/d in 2006.

In addition to these mines, Alabama has one other large gassy mine that appears to be a good candidate for a methane recovery project. North River has been in operation since 1974 and uses the longwall mining method. Table 6-1 shows that the implementation of a methane recovery and use project at the North River mine could reduce annual methane emissions by 0.4 – 1.1 Bcf/yr.

Table 6-1: Alabama Mines

Mine	Company	2006 Coal Production (mm tons)	2006 Ventilation, Drainage and Use Data[1]				
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)	Estimated Methane Used (mmcf/d)
Mines Using Methane (mines at which recovery and use projects have already been developed):							
Blue Creek No. 4	Walter Industries	2.2	6.4	16.8	23.2	3,874	16.8[3]
Blue Creek No. 5[2]	Walter Industries	0.8	2.6	6.8	9.4	4,271	6.8[3]
Blue Creek No. 7	Walter Industries	2.6	8.7	22.9	31.6	4,510	22.9[3]
Oak Grove	Cleveland-Cliffs	1.4	6.7	0.7	7.5	1,922	0.7
Shoal Creek	Drummond Co.	0.8	4.5	0.1	4.7	2,075	0.1
Total for All Mines Using Methane		**7.8**	**28.9**	**47.5**	**76.4**	**-**	**47.5**
Operating But Not Using Methane:							
North River	Chevron Corp.	2.8	4.9	0.0	4.9	648	0.0
TOTAL:[4]		**10.5**	**33.8**	**47.5**	**81.3**	**-**	**47.5**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (North River):	Methane (Bcf/yr)	CO_2 (mmt/yr)
2006 Estimated Total Emissions	1.8	0.8
Estimated Annual Avoided Emissions if Recovery Project is Implemented[5]	0.4 – 1.1	0.2 – 0.5

[1] Chapter 4 explains how these were estimated.
[2] No. 5 mine completed underground mining in December 2006.
[3] JWR reports avoided emissions of all three mines together. Estimated methane used by each mine is calculated based on weighted average of methane drained for each mine.
[4] Values shown here do not always sum to totals due to rounding.
[5] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

In May 2008, Biothermica received authorization from MSHA to conduct a demonstration project at Blue Creek No. 4 mine using the VAMOX regenerative thermal oxidation system to destroy VAM before it is released to the atmosphere. The company estimates GHG emission reductions of approximately 40,000 tons of CO_2 equivalent per year.

Colorado

Colorado has a number of underground mines with relatively low methane emissions, but there are also several deep and gassy mines with high emissions; these mines present potential opportunities for those interested in developing a methane recovery project in the West.

Of the four Colorado mines profiled in this report, West Elk began recovering methane in 2003 for use onsite (heaters). Table 6-2 shows coal production, methane ventilation, and drainage data. In 2006, West Elk liberated an estimated 18.2 mmcf/d (6.6 Bcf/yr), while recovering 9.1 mmcf/d (3.3 Bcf/yr).

Colorado has three additional mines that are potential candidates for methane recovery: Bowie No. 2, Elk Creek, and McClane Canyon. Table 6-2 shows that the implementation of methane recovery and use projects at the three mines could reduce annual methane emissions by 0.8 – 2.3 Bcf/yr.

Table 6-2: Colorado Mines

Mine	Company	2006 Coal Production (mm tons)	2006 Ventilation, Drainage and Use Data[1]				
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)	Estimated Methane Used (mmcf/d)
Mines Using Methane (mines at which recovery and use projects have already been developed):							
West Elk	Arch Coal	6.0	9.1	9.1	18.2	1,107	0.5
Operating But Not Using Methane:							
Bowie No. 2	Union Pacific	4.4	1.5	0.5	2.0	161	0.0
Elk Creek	Oxbow Mining	5.1	5.6	1.9	7.4	530	0.0
McClane Canyon	Wexford Capital	0.3	0.9	0.0	0.9	1,300	0.0
Total for All Mines Not Using Methane		**9.8**	**8.0**	**2.3**	**10.3**	**-**	**0.0**
TOTAL:[2]		**15.8**	**17.1**	**11.5**	**28.6**	**-**	**0.5**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (three mines):	Methane (Bcf/yr)	CO_2 (mmt/yr)
2006 Estimated Total Emissions	3.8	1.7
Estimated Annual Avoided Emissions if Recovery Project is Implemented[3]	0.8 – 2.3	0.3 – 1.0

[1] Chapter 4 explains how these were estimated.
[2] Values shown here do not always sum to totals due to rounding.
[3] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

Illinois

In general, Illinois mines tend to be less gassy than mines in other regions of the country. These mines tend to have lower specific emissions, but many have high total methane emissions depending on their yearly coal production. Accordingly, emissions reductions may be achieved at several of these mines. Coal production and methane ventilation and drainage data on these mines are shown in Table 6-3.

Four Illinois mines are considered to be potential candidates for methane recovery projects. None of the featured Illinois mines have a degasification system in place. Table 6-3 shows that methane emissions from the four Illinois mines totaled an estimated 5.0 Bcf in 2006. The implementation of methane recovery and use projects at the four profiled mines that are not currently using methane could reduce annual methane emissions by 1.0 – 3.0 Bcf/yr.

Table 6-3: Illinois Mines

Mine	Company	2006 Coal Production (mm tons)	2006 Ventilation and Drainage Data[1]			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Operating But Not Using Methane:						
Galatia	Murray Energy	7.2	8.5	0.0	8.5	429
Pattiki Mine	Alliance Res. Part.	2.5	2.0	0.0	2.0	297
Wabash[2]	Foundation Coal	1.2	2.1	0.0	2.1	639
Willow Lake Portal	Peabody Energy	3.6	1.0	0.0	1.0	102
TOTAL[3]:		**14.5**	**13.6**	**0.0**	**13.6**	**-**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (four mines):	**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2006 Estimated Total Emissions	5.0	2.2
Estimated Annual Avoided Emissions if Recovery Projects are Implemented[4]	1.0 – 3.0	0.4 – 1.3

[1] Chapter 4 explains how these data were estimated.
[2] Wabash mine was abandoned in early 2007.
[3] Values shown here do not always sum to totals due to rounding.
[4] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

Indiana

A single Indiana mine, the Gibson mine, is profiled in this report. This room-and-pillar operation, which opened in 2000, is currently considered the gassiest underground mine in Indiana. Table 6-4 shows the mine produced 3.6 million tons of coal in 2006. Gibson mine reported total methane emissions of approximately 1.1 billion cubic feet in 2006, and is not equipped with a degasification system. Based on these emissions, a methane use project may remain viable at the Gibson mine.

Table 6-4: Indiana Mines							
Mine	Company	2006 Coal Production (mm tons)	2006 Ventilation and Drainage Data[1]			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Operating But Not Using Methane:						
Gibson	Alliance Res. Part.	3.6	3.1	0.0	3.1	313
TOTAL[2]:		**3.6**	**3.1**	**0.0**	**3.1**	**-**
Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (Gibson):					**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2006 Estimated Total Emissions					1.1	0.5
Estimated Annual Avoided Emissions if Recovery Projects are Implemented[3]					0.2 – 0.7	0.1 – 0.3

[1] Chapter 4 explains how these data were estimated.
[2] Values shown here do not always sum to totals due to rounding.
[3] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

Kentucky

Kentucky has five operating mines that are good candidates for the development of methane recovery projects. All five mines have methane emissions close to, or slightly above 1 mmcf/d. Table 6-5 shows that methane emissions from the five Kentucky mines totaled an estimated 1.9 Bcf in 2006. Implementation of methane recovery and use projects at these eight mines could reduce annual methane emissions by an estimated 0.4 - 1.2 Bcf/yr.

Table 6-5: Kentucky Mines						
Mine	Company	2006 Coal Production (mm tons)	2006 Ventilation and Drainage Data[1]			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Operating But Not Using Methane:						
Dotiki	Alliance Res. Part.	4.7	0.9	0.0	0.9	71
E3-1	Teco Coal	1.1	0.9	0.0	0.9	298
Jones Fork E-3	CONSOL Energy	1.8	1.1	0.0	1.1	221
Mine No. 2	Alliance Res. Part.	0.8	1.1	0.0	1.1	457
No. 3 Mine	Alliance Res. Part	1.9	1.3	0.0	1.3	262
TOTAL:[2]		**10.3**	**5.3**	**0.0**	**5.3**	**-**
Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (five mines):					**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2006 Estimated Total Emissions					1.9	0.9
Estimated Annual Avoided Emissions if Recovery Projects are Implemented[3]					0.4 – 1.2	0.2 – 0.5

[1] Chapter 4 explains how these data were estimated.
[2] Values shown here do not always sum to totals due to rounding.
[3] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

New Mexico

The San Juan mine, which is owned by the BHP Billiton, is the only New Mexico mine profiled in this report. Coal from the mine is used to supply the nearby San Juan generating station. This longwall mine opened in 2002 and methane recovery began in 2003. As shown in Table 6-6, San Juan produced ventilation emissions of 3.9 mmcf/d in 2006, and total methane liberated was 6.5 mmcf/d (2.4 Bcf/yr) in 2006. The mine employs a degasification system which uses both vertical gob vent boreholes and in-mine, horizontal, pre-drainage boreholes. The mine recovered close to 1 Bcf in 2006. Recovered methane was used for pipeline injection from 2003-2005, however San Juan owns only the coal rights. The mine can vent the gas while mining, but cannot recover the gas for commercial benefit. As such, there is little incentive for the mine to drain more gas for the two oil and gas operators who have the rights to the CBM on the property.

Table 6-6: New Mexico Mines

Mine	Company	2006 Coal Production (mm tons)	2006 Ventilation and Drainage Data[1]			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Operating But Not Using Methane:						
San Juan South	BHP Billiton	7.0	3.9	2.6	6.5	340
TOTAL[2]:		**7.0**	**3.9**	**2.6**	**6.5**	**-**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (San Juan South):	**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2006 Estimated Total Emissions	2.4	1.1
Estimated Annual Avoided Emissions if Recovery Projects are Implemented[3]	0.5 – 1.4	0.2 – 0.6

[1] Chapter 4 explains how these data were estimated.
[2] Values shown here do not always sum to totals due to rounding.
[3] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

Ohio

As with the Illinois mines, Ohio mines tend to be less gassy than mines in other regions of the country. Two operating Ohio mines are profiled in this report, the Century and Powhatan No. 6 mines. As shown in Table 6-7, these mines produced 10.8 million tons in 2006 and had ventilation emissions of 3.9 mmcf/d. As of 2006, no drainage systems were in place in either mine. The implementation of methane recovery and use projects at the two Ohio mines could reduce annual methane emissions by 0.3 - 0.8 Bcf/yr.

Table 6-7: Ohio Mines							
Mine	Company	2006 Coal Production (mm tons)	2006 Ventilation and Drainage Data[1]				
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Operating But Not Using Methane:						
Century	Murray Energy	6.5	1.9	0.0	1.9	105
Powhatan No. 6	Murray Energy	4.4	2.0	0.0	2.0	167
TOTAL:[2]		**10.8**	**3.9**	**0.0**	**3.9**	**-**
Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (two mines):					**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2006 Estimated Total Emissions					1.4	0.6
Estimated Annual Avoided Emissions if Recovery Projects are Implemented[3]					0.3 – 0.8	0.1 – 0.4

[1] Chapter 4 explains how these data were estimated.
[2] Values shown here do not always sum to totals due to rounding.
[3] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

Oklahoma

A single Oklahoma mine, the South Central mine, is profiled in this report. This room-and-pillar operation, which opened in 1995, is currently considered the gassiest underground mine in Oklahoma. As shown in Table 6-8, in 2006, the mine produced 0.4 million tons annually and reported total methane emissions of approximately 0.3 billion cubic feet in 2006. Based on these emissions, and a history of gassy mines in the Arkoma Basin, a coalmine methane project may be viable at the South Central mine.

Table 6-8: Oklahoma Mines						
Mine	Company	2006 Coal Production (mm tons)	2006 Ventilation and Drainage Data[1]			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Operating But Not Using Methane:						
South Central	S. Central Coal Co.	0.4	0.9	0.0	0.9	735
TOTAL[2]:		**0.4**	**0.9**	**0.0**	**0.9**	**-**
Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (South Central):					**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2006 Estimated Total Emissions					0.3	0.1
Estimated Annual Avoided Emissions if Recovery Projects are Implemented[3]					0.1 – 0.2	0.0 – 0.1

[1] Chapter 4 explains how these data were estimated.
[2] Values shown here do not always sum to totals due to rounding.
[3] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

Pennsylvania

As demonstrated in Table 6-9, two of the mines at which successful methane recovery and use projects have already been developed are located in Pennsylvania. The Cumberland and Emerald mines are both longwall operations, and are both owned by Foundation Coal. The total methane drained at the two Foundation Coal mine properties equaled 5.7 mmcf/d in 2006. It is assumed that all methane drained is injected into pipeline for sales.

Three operating Pennsylvania mines are good candidates for methane recovery and use and are profiled in this report. Coal production, ventilation, and drainage data on these mines are shown in Table 6-9.

In 2006, the three mines that are not using methane liberated about 25.9 mmcf/d (9.4 Bcf/yr) of methane. Several of these mines are located in Greene County, Pennsylvania. In fact, Greene County is the location of the two of the three largest underground mines in the United States, CONSOL's Enlow Fork and Bailey mines. These mines are adjacent to one another and are often referred to as the Bailey-Enlow Fork complex.

Table 6-9 shows that the implementation of recovery and use projects at the three profiled Pennsylvania mines that are currently operating could reduce annual methane emissions by 1.9 – 5.7 Bcf/yr.

Table 6-9: Pennsylvania Mines

Mine	Company	2006 Coal Production (mm tons)	2006 Ventilation, Drainage and Use Data[1]				
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)	Estimated Methane Used (mmcf/d)
Mines Using Methane (mines at which recovery and use projects have already been developed):							
Cumberland	Foundation Coal	7.5	6.7	3.4	10.1	491	3.4
Emerald	Foundation Coal	5.9	5.2	2.3	7.4	458	2.3
Total for All Mines Using Methane		**13.4**	**11.9**	**5.7**	**17.5**	**-**	**5.7**
Operating But Not Using Methane:							
Bailey	CONSOL Energy	10.2	7.5	3.2	10.7	383	0.0
Eighty-Four	CONSOL Energy	3.5	5.1	0.0	5.1	532	0.0
Enlow Fork	CONSOL Energy	10.7	10.1	0.0	10.1	344	0.0
Total for All Mines Not Using Methane		**24.4**	**22.7**	**3.2**	**25.9**	**-**	**0.0**
TOTAL:[2]		**37.8**	**34.5**	**8.9**	**43.4**	**-**	**5.7**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (three mines):	**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2006 Estimated Total Emissions	9.4	4.2
Estimated Annual Avoided Emissions if Recovery Project is Implemented[3]	1.9 – 5.7	0.8 – 2.5

[1] Chapter 4 explains how these were estimated.
[2] Values shown here do not always sum to totals due to rounding.
[3] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

In early 2007, CONSOL Energy – in partnership with CNX Gas Corporation and Ingersoll Rand Energy Systems – successfully demonstrated electricity generation by a microturbine fueled by unprocessed CMM at Bailey mine. The unit will undergo a one-year operational phase. The 70 kW microturbine is expected to generate approximately 500 MWh of electricity while consuming approximately 8 mmcf of methane that would have otherwise been emitted to the atmosphere (USEPA, 2007b).

Utah

Utah has a number of underground mines with relatively low methane emissions along the Wasatch Plateau, but it also has several deep and gassy mines with high methane emissions located nearby in the Uinta Basin. As with Colorado, these mines present potential opportunities for those interested in developing a methane recovery project in the West. Three operating Utah mines are good candidates for methane recovery and use and are profiled in this report.

As shown in Table 6-10, the Aberdeen mine is currently the gassiest in the state with 2006 estimated specific emissions of 1,202 cf/ton. However, Dugout Canyon and West Ridge liberated a total of 1.7 mmcf/d and 3.6 mmcf/d in 2006, respectively. These Utah mines have produced high total methane emissions depending on their yearly coal production. Table 6-10 shows that the implementation of methane recovery and use projects at these three operating Utah mines could reduce annual methane emissions by 0.9 – 2.7 Bcf/yr.

Table 6-10: Utah Mines

Mine	Company	2006 Coal Production (mm tons)	2006 Ventilation and Drainage Data[1]			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (est.) (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Operating But Not Using Methane:						
Aberdeen	Murray Energy	2.1	5.2	1.7	6.9	1,202
Dugout Canyon	Arch Coal	4.4	1.3	0.4	1.7	141
West Ridge	Murray Energy	3.0	3.6	0.0	3.6	430
TOTAL:[2]		**9.5**	**10.0**	**2.1**	**12.1**	**-**
Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (three mines):					**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2006 Estimated Total Emissions					4.4	2.0
Estimated Annual Avoided Emissions if Recovery Projects are Implemented[3]					0.9 – 2.7	0.4 – 1.2

[1] Chapter 4 explains how these data were estimated.
[2] Values shown here do not always sum to totals due to rounding.
[3] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

In January 2007, methane capture began at Aberdeen mine. The mine captures and processes between 3 and 7 mmcf/d of methane, and the gas is then compressed and injected into a natural gas pipeline. It is the first large-scale capture of methane from a coal mine west of the Mississippi River. However, technical problems have limited the facility to run at 30-40% of capacity (Best, 2007).

Virginia

As Table 6-11 demonstrates, two of the mines at which successful methane recovery and use projects have already been developed are located in Virginia. The Buchanan and the VP 8 mines are both longwall operations, and are owned by CONSOL Energy. The total methane drained at the two CONSOL Virginia mine properties equaled 79.7 mmcf/d in 2006. This number significantly exceeds ventilation emissions of 11.6 mmcf/d, which indicates that recovery efficiencies (greater that 80% at both mines) are higher than standard EPA assumptions. Table 6-11 shows that CONSOL operates the largest active methane recovery project in the United States.

Table 6-11: Virginia Mines

Mine	Company	2006 Coal Production (mm tons)	2006 Ventilation, Drainage and Use Data[1] Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)	Estimated Methane Used (mmcf/d)
Mines Using Methane (mines at which recovery and use projects have already been developed):							
Buchanan	CONSOL Energy	5.0	8.4	63.9	72.3	5,270	51.3[4]
VP 8[2]	CONSOL Energy	0.3	3.2	15.8	19.0	24,295[3]	12.7[4]
Total for All Mines Using Methane		**5.3**	**11.6**	**79.7**	**91.4**	**-**	**63.9**
Operating But Not Using Methane:							
Deep Mine #26	Alpha Nat. Res.	2.0	3.7	0.0	3.7	672	0.0
Mile Branch	CONSOL Energy	0.3	1.2	0.0	1.2	1,393	0.0
No.2	Alpha Nat. Res.	0.2	0.8	0.0	0.8	1,498	0.0
Total for All Mines Not Using Methane		**2.5**	**5.7**	**0.0**	**5.7**	**-**	**0.0**
TOTAL:[5]		**7.8**	**17.3**	**79.7**	**97.0**	**-**	**63.9**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (three mines	**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2006 Estimated Total Emissions	2.1	0.9
Estimated Annual Avoided Emissions if Recovery Project is Implemented[6]	0.4– 1.2	0.2– 0.6

[1] Chapter 4 explains how these were estimated.
[2] VP 8 completed underground mining in spring of 2006 due to lack of reserves, however gas recovery continues.
[3] CONSOL Energy's VP 8 mine in Virginia had specific emissions of 24,295 cf/ton based on total methane liberated in 2006. However, the mine was shut down in spring 2006 but gas recovery continued, leading to elevated methane liberated per ton of coal produced. Based on first quarter coal production - the last full quarter of production - of 0.259 million short tons and quarterly methane liberation of 1,734 mmcf, specific emissions for the last full quarter of operation were 6,695 cf/ton.
[4] CONSOL reports avoided emissions of Buchanan and VP 8 mines together. Estimated methane used by each mine is calculated based on weighted average of methane drained for each mine.
[5] Values shown here do not always sum to totals due to rounding.
[6] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

West Virginia

Of the 50 mines profiled in this report, 13 are located in West Virginia. Of these mines, four are currently recovering methane for sale. Coal production, methane ventilation, and drainage data on these mines are shown in Table 6-12.

The four profiled mines that are recovering methane for sale are the Blacksville No. 2, Federal No. 2, Loveridge No. 22, and Pinnacle mines. In 2006, these mines liberated an estimated 33.4 mmcf/d (12.2 Bcf/yr), while recovering 9.9 mmcf/d (3.6 Bcf/yr). Federal No. 2 recovered and sold about 0.2 mmcf/d of methane in 2006, while Pinnacle sold 4.6 mmcf/d of methane to a gas marketing company, the project at Blacksville No. 2 sold about 2.5 mmcf/d, and Loveridge No. 22 sold 1.8 mmcf/d in 2006.

Eight of the West Virginia mines profiled in this report are located in the Northern Appalachian Basin; five of these are owned by CONSOL Energy. The remaining five operating mines that are profiled are located in the Central Appalachian Basin. Table 6-12 shows that the implementation of methane recovery and use projects at the nine operating mines that do not already use methane could reduce annual methane emissions by 2.6 – 7.7 Bcf/yr.

Table 6-12: West Virginia Mines								
			2006 Ventilation, Drainage and Use Data[1]					
Mine	Company	2006 Coal Production (mm tons)	Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)	Estimated Methane Used (mmcf/d)
Mines Using Methane (mines at which recovery and use projects have already been developed):							
Blacksville No. 2	CONSOL Energy	5.0	7.2	2.5	9.7	701	2.5[2]
Federal No. 2	Patriot Coal	4.6	5.7	1.0	6.7	531	0.2
Loveridge No. 22	CONSOL Energy	6.4	5.3	1.8	7.1	406	1.8[2]
Pinnacle	Cleveland-Cliffs	2.0	5.2	4.6	9.8	1,785	4.6
Total for All Mines Using Methane		**18.1**	**23.5**	**9.9**	**33.4**	**-**	**9.1**
Operating But Not Using Methane:							
American Eagle	Speed Mining	2.4	3.0	2.0	5.0	753	0.0
Beckley Crystal	Baylor Mining	0.3	2.0	0.0	2.0	2,185	0.0
Dakota No. 2[3]	Magnum Coal	0.6	1.0	0.0	1.0	601	0.0
Eagle	Newtown Energy	1.3	1.2	0.0	1.2	350	0.0
Justice #1	Massey Energy	0.9	0.9	0.0	0.9	363	0.0
McElroy	CONSOL Energy	10.5	12.8	2.3	15.1	525	0.0
Robinson Run No. 95	CONSOL Energy	5.7	4.0	1.7	5.7	361	0.0
Shoemaker	CONSOL Energy	1.0	3.1	0.0	3.1	1,159	0.0
Whitetail Kittanning	Alpha Nat. Res.	1.4	1.4	0.0	1.4	366	0.0
Total for All Mines Not g Methane		**24.1**	**29.4**	**5.9**	**35.3**	**-**	**0.0**
TOTAL:[4]		**42.2**	**52.9**	**15.8**	**68.7**	**-**	**9.1**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (nine mines):	Methane (Bcf/yr)	CO_2 (mmt/yr)
2006 Estimated Total Emissions	12.9	5.7
Estimated Annual Avoided Emissions if Recovery Project is Implemented[5]	2.6 – 7.7	1.1 – 3.4

[1] Chapter 4 explains how these were estimated.

[2] Assumes Blacksville No. 2 and Loveridge No. 22 avoided emissions reported together. Estimated methane use by each mine is calculated based on weighted average of methane drained for each mine.

[3] Dakota No. 2 abandoned in 2007.

[4] Values shown here do not always sum to totals due to rounding.

[5] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

6. Profiled Mines (continued)

Alabama Mines

Blue Creek No. 4
Blue Creek No. 5
Blue Creek No. 7
North River
Oak Grove
Shoal Creek

Mine Status:	Active		
Drainage System:	Yes	**2006 Rank:**	11
Use Project:	Pipeline	**Updated:**	05/09/2008

Blue Creek No. 4

GEOGRAPHIC DATA

Basin: Black Warrior

State: AL

Coalbed: Blue Creek / Mary Lee

County: Tuscaloosa

CORPORATE INFORMATION

Current Operator: Jim Walter Resources Inc

Owner/Parent Company: Walter Industries Inc

Parent Company Web Site: www.jimwalterresources.com

Previous Owner(s): None in last 10 years

Previous or Alternate Name of Mine: No. 4 Mine

MINE ADDRESS

Contact Name: Keith Shalvey, Mine Mgr.

Phone Number: (205) 554-6450

Mailing Address: 14730 Lock 17 Rd

City: Brookwood **State:** AL **ZIP:** 35444

GENERAL INFORMATION

Number of Employees at Mine: 471

Mining Method: Longwall

Year of Initial Production: 1976

Primary Coal Use: Metallurgical

Life Expectancy: 2020

Sulfur Content of Coal Produced: 0.75% - 0.95%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 14,200

Depth to Seam (ft): 1,900

Seam Thickness (ft): 5.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	2.8	2.8	3.1	3.0	2.2
Estimated Total Methane Liberated (million cf/day):	26.5	20.0	16.5	25.5	23.2
Emission from Ventilation Systems:	11.7	8.7	8.2	6.3	6.4
Estimated Methane Drained:	14.8	11.4	8.3	19.2	16.8
Estimated Specific Emissions (cf/ton):	3434	2614	1977	3067	3874
Methane Used (million cf/day):	14.8	11.4	8.3	19.2	16.8

Estimated Current Drainage Efficiency: 73%

Estimated Current Market Penetration: 100%

Drainage System Used: Vertical Gob Boreholes; Horizontal Pre-Mine Boreholes; Vertical Pre-Mine Boreholes

Blue Creek No. 4 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2006 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.753	1.50	2.259
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	11.8%	23.6%	35.4%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	2.7%	5.5%	8.2%

Power Generation Potential

Utility Electric Supplier: Alabama Power Co

Transmission Line in County: Yes

Parent Corporation of Utility: Southern Co

	MW	GWh/year
Total Electricity Demand (2006 data):	17.3	65.6
Mine Electricity Demand:	13.6	52.5
Prep Plant Electricity Demand:	3.7	13.1
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	17.6	154.0
Assuming 40% Recovery Efficiency:	35.2	308.1
Assuming 60% Recovery Efficiency:	52.8	462.1

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	1.7
Assuming 40% Recovery (Bcf):	3.4
Assuming 60% Recovery (Bcf):	5.1

Description of Surrounding Terrain: Open Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: El Paso Corporation

Distance to Pipeline (miles): 5.3 **Pipeline Diameter (inches):** 4.0

Owner of Next Nearest Pipeline: El Paso Corporation

Distance to Next Nearest Pipeline (miles): 6.0 **Pipeline Diameter (inches):** 16.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Gorgas **Distance to Plant (miles):** 25

Other Nearby Industrial / Institutional Facilities: Tuscaloosa Co General Manufacturing: steel, lumber, asphalt, screens, spandex, others; Steel plants; Chemical: detergent, paint, industrial gases, others

Mine Status: Active (Abandoned in 2007)
Drainage System: Yes
Use Project: Pipeline

2006 Rank: 29
Updated: 05/09/2008

Blue Creek No. 5

GEOGRAPHIC DATA

Basin: Black Warrior

State: AL

Coalbed: Blue Creek

County: Tuscaloosa

CORPORATE INFORMATION

Current Operator: Jim Walter Resources Inc

Owner/Parent Company: Walter Industries Inc

Parent Company Web Site: www.jimwalterresources.com

Previous Owner(s): None in last 10 years

Previous or Alternate Name of Mine: No. 5 Mine

MINE ADDRESS

Contact Name: Trent Thrasher, Mine Mgr.

Phone Number: (205) 554-6550

Mailing Address: 12972 Lock 17 Rd

City: Brookwood

State: AL

ZIP: 35444

GENERAL INFORMATION

Number of Employees at Mine: 5

Mining Method: Longwall

Year of Initial Production: 1978

Primary Coal Use: Steam, Metallurgical

Life Expectancy: 2006

Sulfur Content of Coal Produced: 0.72% - 0.8%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 13,300

Depth to Seam (ft): 2,200

Seam Thickness (ft): 6.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	0.7	1.4	1.5	0.7	0.8
Estimated Total Methane Liberated (million cf/day):	14.2	18.0	21.2	10.9	9.4
Emission from Ventilation Systems:	6.3	7.8	10.6	2.7	2.6
Estimated Methane Drained:	8.0	10.2	10.7	8.2	6.8
Estimated Specific Emissions (cf/ton):	7639	4749	5221	6044	4271
Methane Used (million cf/day):	8.0	10.2	10.7	8.2	6.8

Estimated Current Drainage Efficiency: 73%

Estimated Current Market Penetration: 100%

Drainage System Used: Vertical Gob Boreholes; Horizontal Pre-Mine Boreholes; Vertical Pre-Mine Boreholes

Blue Creek No. 5 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2006 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.306	0.61	0.918
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	13.9%	27.8%	41.7%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	3.2%	6.4%	9.6%

Power Generation Potential

Utility Electric Supplier: Alabama Power Co

Transmission Line in County: Yes

Parent Corporation of Utility: Southern Co

	MW	GWh/year
Total Electricity Demand (2006 data):	6.4	24.2
Mine Electricity Demand:	5.0	19.3
Prep Plant Electricity Demand:	1.4	4.8
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	7.1	62.6
Assuming 40% Recovery Efficiency:	14.3	125.2
Assuming 60% Recovery Efficiency:	21.4	187.8

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.7
Assuming 40% Recovery (Bcf):	1.4
Assuming 60% Recovery (Bcf):	2.1

Description of Surrounding Terrain: Open Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: El Paso Corporation

Distance to Pipeline (miles): 3.5

Pipeline Diameter (inches): 16.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA

Pipeline Diameter (inches): NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Gorgas

Distance to Plant (miles): 27

Other Nearby Industrial / Institutional Facilities: Tuscaloosa Co General Manufacturing: steel, lumber, asphalt, screens, spandex, others; Steel plants; Chemical: detergent, paint, industrial gases, others

Mine Status:	Active			
Drainage System:	Yes		**2006 Rank:**	4
Use Project:	Pipeline		**Updated:**	05/09/2008

Blue Creek No. 7

GEOGRAPHIC DATA

Basin: Black Warrior

State: AL

Coalbed: Blue Creek / Mary Lee

County: Tuscaloosa

CORPORATE INFORMATION

Current Operator: Jim Walter Resources Inc

Owner/Parent Company: Walter Industries Inc

Parent Company Web Site: www.jimwalterresources.com

Previous Owner(s): None in last 10 years

Previous or Alternate Name of Mine: No. 7 Mine

MINE ADDRESS

Contact Name: Trent Thrasher, Mine Mgr.

Phone Number: (205) 554-6750

Mailing Address: 18069 Hannah Creek Rd

City: Brookwood **State:** AL **ZIP:** 35444

GENERAL INFORMATION

Number of Employees at Mine: 692

Mining Method: Longwall

Year of Initial Production: 1978

Primary Coal Use: Metallurgical

Life Expectancy: 2039

Sulfur Content of Coal Produced: 0.58% - 0.75%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 14,500

Depth to Seam (ft): 1,900

Seam Thickness (ft): 6.4

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	2.0	1.9	2.3	2.0	2.6
Estimated Total Methane Liberated (million cf/day):	25.1	22.5	15.9	31.8	31.6
Emission from Ventilation Systems:	11.0	9.8	7.9	7.8	8.7
Estimated Methane Drained:	14.0	12.8	8.0	24.0	22.9
Estimated Specific Emissions (cf/ton):	4620	4421	2482	5697	4510
Methane Used (million cf/day):	14.0	12.8	8.0	24.0	22.9

Estimated Current Drainage Efficiency: 73%

Estimated Current Market Penetration: 100%

Drainage System Used: Vertical Gob Boreholes; Horizontal Pre-Mine Boreholes; Vertical Pre-Mine Boreholes

Blue Creek No. 7 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	1.025	2.05	3.076
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	13.5%	26.9%	40.4%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	3.1%	6.2%	9.3%

Power Generation Potential

Utility Electric Supplier: Alabama Power Co

Transmission Line in County: Yes

Parent Corporation of Utility: Southern Co

	MW	GWh/year
Total Electricity Demand (2006 data):	20.3	76.7
Mine Electricity Demand:	15.9	61.4
Prep Plant Electricity Demand:	4.4	15.3
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	23.9	209.7
Assuming 40% Recovery Efficiency:	47.9	419.5
Assuming 60% Recovery Efficiency:	71.8	629.2

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	2.3
Assuming 40% Recovery (Bcf):	4.6
Assuming 60% Recovery (Bcf):	6.9

Description of Surrounding Terrain: Open Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: El Paso Corporation

Distance to Pipeline (miles): 5.1

Pipeline Diameter (inches): 16.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA

Pipeline Diameter (inches): NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Gorgas

Distance to Plant (miles): 23

Other Nearby Industrial / Institutional Facilities: Tuscaloosa Co General Manufacturing: steel, lumber, asphalt, screens, spandex, others; Steel plants; Chemical: detergent, paint, industrial gases, others

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 19
Updated: 05/09/2008

North River Mine

GEOGRAPHIC DATA

Basin: Black Warrior
State: AL
Coalbed: Pratt
County: Tuscaloosa

CORPORATE INFORMATION

Current Operator: Chevron Mining Inc

Owner/Parent Company: Chevron Corporation
Parent Company Web Site: www.chevron.com
Previous Owner(s): None in last 10 years
Previous or Alternate Name of Mine: North River No. 1

MINE ADDRESS

Contact Name: Mark Premo, Gen. Mine Mgr.
Phone Number: (205) 333-5000
Mailing Address: 12398 New Lexington Rd
City: Berry
State: AL
ZIP: 35546

GENERAL INFORMATION

Number of Employees at Mine: 404
Mining Method: Longwall
Year of Initial Production: 1974
Primary Coal Use: Steam, Metallurgical
Life Expectancy: NA
Sulfur Content of Coal Produced: 1.5% - 1.85%
Prep Plant Located on Site: Yes
BTUs/lb of Coal Produced: 12,000
Depth to Seam (ft): 650
Seam Thickness (ft): 4.7

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	3.4	3.5	3.7	3.4	2.8
Estimated Total Methane Liberated (million cf/day):	5.1	4.2	5.5	4.2	4.9
Emission from Ventilation Systems:	5.1	4.2	5.5	4.2	4.9
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	547	437	537	449	648
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA
Estimated Current Market Penetration: NA
Drainage System Used: None

North River Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.159	0.31	0.477
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	2.3%	4.7%	7.0%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.5%	1.1%	1.6%

Power Generation Potential

Utility Electric Supplier: Alabama Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: Southern Co

	MW	GWh/year
Total Electricity Demand (2006 data):	21.9	82.9
Mine Electricity Demand:	17.2	66.3
Prep Plant Electricity Demand:	4.7	16.6
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	3.7	32.6
Assuming 40% Recovery Efficiency:	7.4	65.1
Assuming 60% Recovery Efficiency:	11.1	97.7

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.4
Assuming 40% Recovery (Bcf):	0.7
Assuming 60% Recovery (Bcf):	1.1

Description of Surrounding Terrain: Open Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: El Paso Corporation

Distance to Pipeline (miles): 1.4 **Pipeline Diameter (inches):** 16.0

Owner of Next Nearest Pipeline: El Paso Corporation

Distance to Next Nearest Pipeline (miles): 3.1 **Pipeline Diameter (inches):** 8.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Gorgas **Distance to Plant (miles):** 24

Other Nearby Industrial / Institutional Facilities: Manufacturing including: apparel, wood, concrete and quarry tile, logging and lumber, structural steel fabrication

Mine Status: Active
Drainage System: Yes
Use Project: Pipeline

2006 Rank: 9
Updated: 05/09/2008

Oak Grove Mine

GEOGRAPHIC DATA

Basin: Black Warrior
State: AL
Coalbed: Blue Creek
County: Jefferson

CORPORATE INFORMATION

Current Operator: Oak Grove Resources LLC

Owner/Parent Company: Cleveland-Cliffs Inc
Parent Company Web Site: www.cleveland-cliffs.com
Previous Owner(s): US Steel Mining Co LLC
Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: John Hedrick
Phone Number: (205) 497-3602
Mailing Address: 8800 Oak Grove Mine Rd
City: Adger
State: AL
ZIP: 35006

GENERAL INFORMATION

Number of Employees at Mine: 407
Mining Method: Longwall
Year of Initial Production: 1981
Primary Coal Use: Steam, Metallurgical
Life Expectancy: 2023
Sulfur Content of Coal Produced: 0.5% - 0.55%
Prep Plant Located on Site: No
BTUs/lb of Coal Produced: 14,000
Depth to Seam (ft): 1,000
Seam Thickness (ft): 5.2

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	1.9	1.7	1.5	1.7	1.4
Estimated Total Methane Liberated (million cf/day):	14.8	14.4	12.1	9.8	7.5
Emission from Ventilation Systems:	5.1	8.5	10.0	7.3	6.7
Estimated Methane Drained:	9.7	5.9	2.1	2.5	0.7
Estimated Specific Emissions (cf/ton):	2775	3047	2944	2075	1922
Methane Used (million cf/day):	9.7	5.9	2.1	1.7	0.7

Estimated Current Drainage Efficiency: 10%

Estimated Current Market Penetration: 100%

Drainage System Used: Vertical Gob Boreholes; Horizontal Pre-Mine Boreholes; Vertical Pre-Mine Boreholes

Oak Grove Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.242	0.48	0.725
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	5.9%	11.9%	17.8%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.4%	2.7%	4.1%

Power Generation Potential

Utility Electric Supplier: Alabama Power Co

Transmission Line in County: Yes

Parent Corporation of Utility: Southern Co

	MW	GWh/year
Total Electricity Demand (2006 data):	11.2	42.5
Mine Electricity Demand:	8.8	34.0
Prep Plant Electricity Demand:	2.4	8.5
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	5.6	49.5
Assuming 40% Recovery Efficiency:	11.3	98.9
Assuming 60% Recovery Efficiency:	16.9	148.4

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.5
Assuming 40% Recovery (Bcf):	1.1
Assuming 60% Recovery (Bcf):	1.6

Description of Surrounding Terrain: Open Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: El Paso Corporation

Distance to Pipeline (miles): 3.7

Pipeline Diameter (inches): 24.0

Owner of Next Nearest Pipeline: El Paso Corporation

Distance to Next Nearest Pipeline (miles): 4.2

Pipeline Diameter (inches): 12.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Miller

Distance to Plant (miles): 20

Other Nearby Industrial / Institutional Facilities: Jefferson county-wide industry includes - Chemical: Industrial gases, pigments, cosmetics & perfumes, paints, ink; Textile: Cordage, chains, ropes, clothes, slings; Steel pipe and tubing; Misc. other types of general manufacturing

Mine Status: Active
Drainage System: Yes
Use Project: Pipeline

2006 Rank: 20
Updated: 05/09/2008

Shoal Creek

GEOGRAPHIC DATA

Basin: Black Warrior
State: AL
Coalbed: Blue Creek / Mary Lee
County: Jefferson

CORPORATE INFORMATION

Current Operator: Drummond Company Inc

Owner/Parent Company: Drummond Company Inc
Parent Company Web Site: www.drummondco.com
Previous Owner(s): None in last 10 years
Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Ken McCoy, General Mgr.
Phone Number: (205) 491-6200

Mailing Address: PO Box 1549

City: Jasper **State:** AL **ZIP:** 35501

GENERAL INFORMATION

Number of Employees at Mine: 524
Mining Method: Longwall
Year of Initial Production: 1994
Primary Coal Use: Steam
Life Expectancy: NA
Sulfur Content of Coal Produced: 0.63% - 1.1%
Prep Plant Located on Site: Yes
BTUs/lb of Coal Produced: 12,464
Depth to Seam (ft): 1150
Seam Thickness (ft): 7.0 - 11.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	4.0	3.8	3.8	2.2	0.8
Estimated Total Methane Liberated (million cf/day):	7.4	8.7	13.1	10.3	4.7
Emission from Ventilation Systems:	6.7	8.2	11.4	8.3	4.5
Estimated Methane Drained:	0.7	0.5	1.8	2.0	0.1
Estimated Specific Emissions (cf/ton):	683	828	1258	1701	2075
Methane Used (million cf/day):	0.7	0.5	0.6	0.1	0.1

Estimated Current Drainage Efficiency: 3%

Estimated Current Market Penetration: 100%

Drainage System Used: Vertical Gob Boreholes with Pumps

Shoal Creek (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.151	0.300	0.453
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	7.2%	14.4%	21.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.7%	3.3%	5.0%

Power Generation Potential

Utility Electric Supplier: Alabama Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: Southern Co

	MW	GWh/year
Total Electricity Demand (2006 data):	6.5	24.5
Mine Electricity Demand:	5.1	19.6
Prep Plant Electricity Demand:	1.4	4.9
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	3.5	30.9
Assuming 40% Recovery Efficiency:	7.0	61.7
Assuming 60% Recovery Efficiency:	10.6	92.6

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.3
Assuming 40% Recovery (Bcf):	0.7
Assuming 60% Recovery (Bcf):	1.0

Description of Surrounding Terrain: Open Hills/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: El Paso Corporation

Distance to Pipeline (miles): 1.3 **Pipeline Diameter (inches):** 24.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Gorgas **Distance to Plant (miles):** 12

Other Nearby Industrial / Institutional Facilities: Jefferson county-wide industry includes - Chemical: Industrial gases, pigments, cosmetics & perfumes, paints, ink; Textile: Cordage, chains, ropes, clothes, slings; Steel pipe and tubing; Misc. other types of general manufacturing

6. Profiled Mines (continued)

Colorado Mines

Bowie No. 2
Elk Creek
McClane Canyon
West Elk

Mine Status: Active
Drainage System: Yes
Use Project: None

2006 Rank: 35
Updated: 05/09/2008

Bowie No. 2

GEOGRAPHIC DATA

Basin: Central Rockies

State: CO

Coalbed: B&D Seams

County: Delta

CORPORATE INFORMATION

Current Operator: Bowie Resources LLC

Owner/Parent Company: Union Pacific

Parent Company Web Site: http://www.uprr.com/customers/

Previous Owner(s): Coors Energy

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Allen Meckley

Phone Number: (970) 929-5240

Mailing Address: 1855 Old Hwy 133

City: Paonia **State:** CO **ZIP:** 81428

GENERAL INFORMATION

Number of Employees at Mine: 278

Mining Method: Longwall

Year of Initial Production: 1998

Primary Coal Use: Steam

Life Expectancy:

Sulfur Content of Coal Produced: 0.5%

Prep Plant Located on Site: No

BTUs/lb of Coal Produced: 12,000

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	5.4	4.9	4.1	1.9	4.4
Estimated Total Methane Liberated (million cf/day):	0.4	0.6	0.4	0.4	2.0
Emission from Ventilation Systems:	0.3	0.4	0.3	0.3	1.5
Estimated Methane Drained:	0.1	0.1	0.1	0.1	0.5
Estimated Specific Emissions (cf/ton):	28	41	37	85	161
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 25%

Estimated Current Market Penetration: 0%

Drainage System Used: Vertical Gob Boreholes with Pumps

Bowie No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.063	0.120	0.190
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.6%	1.2%	1.7%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.3%	0.4%

Power Generation Potential

Utility Electric Supplier: Delta-Montrose Electric Association **Transmission Line in County:** Yes

Parent Corporation of Utility: Touchstone Energy Cooperatives

	MW	GWh/year
Total Electricity Demand (2006 data):	35.0	132.6
Mine Electricity Demand:	27.5	106.1
Prep Plant Electricity Demand:	7.5	26.5
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	1.5	12.9
Assuming 40% Recovery Efficiency:	3.0	25.9
Assuming 60% Recovery Efficiency:	4.4	38.8

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.3
Assuming 60% Recovery (Bcf):	0.4

Description of Surrounding Terrain: NA

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Rocky Mountain Natural Gas

Distance to Pipeline (miles): < 20.0 **Pipeline Diameter (inches):** 8.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Nucla **Distance to Plant (miles):** 70

Other Nearby Industrial / Institutional Facilities:

Mine Status: Active
Drainage System: Yes
Use Project: None

2006 Rank: 13
Updated: 05/09/2008

Elk Creek Mine

GEOGRAPHIC DATA

Basin: Uinta

State: CO

Coalbed: D-seam

County: Gunnison

CORPORATE INFORMATION

Current Operator: Oxbow Mining LLC

Owner/Parent Company: Oxbow Carbon & Materials Inc

Parent Company Web Site: www.oxbow.com

Previous Owner(s): None

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Randy Litwiller, Mine Mgr.

Phone Number: (970) 929-5122

Mailing Address: PO Box 535

City: Somerset

State: CO

ZIP: 81434

GENERAL INFORMATION

Number of Employees at Mine: 320

Mining Method: Longwall

Year of Initial Production: 2002

Primary Coal Use: Steam

Life Expectancy: 2017

Sulfur Content of Coal Produced: 0.45%

Prep Plant Located on Site: No

BTUs/lb of Coal Produced: 12,128

Depth to Seam (ft): 1000-2000

Seam Thickness (ft): 9.0 - 15.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	0.6	4.6	6.6	6.5	5.1
Estimated Total Methane Liberated (million cf/day):	0.1	1.1	5.1	5.5	7.4
Emission from Ventilation Systems:	0.1	1.1	3.8	4.1	5.6
Estimated Methane Drained:	-	-	1.3	1.4	1.9
Estimated Specific Emissions (cf/ton):	33	91	282	308	530
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 25%

Estimated Current Market Penetration: 0%

Drainage System Used: Vertical Gob Boreholes with Pumps

Elk Creek Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.242	0.48	0.725
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.9%	3.8%	5.7%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.4%	0.9%	1.3%

Power Generation Potential

Utility Electric Supplier: Delta-Montrose Electric Association

Transmission Line in County: Planned

Parent Corporation of Utility: Touchstone Energy Cooperatives

	MW	GWh/year
Total Electricity Demand (2006 data):	40.7	153.8
Mine Electricity Demand:	31.9	123.1
Prep Plant Electricity Demand:	8.7	30.8
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	5.6	49.4
Assuming 40% Recovery Efficiency:	11.3	98.9
Assuming 60% Recovery Efficiency:	16.9	148.3

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.5
Assuming 40% Recovery (Bcf):	1.1
Assuming 60% Recovery (Bcf):	1.6

Description of Surrounding Terrain: Hilly/Mountainous

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Kinder Morgan Inc

Distance to Pipeline (miles): 10.9 **Pipeline Diameter (inches):** 4.0

Owner of Next Nearest Pipeline: Rocky Mountain Natural Gas

Distance to Next Nearest Pipeline (miles): 27.0 **Pipeline Diameter (inches):** 6.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Nucla **Distance to Plant (miles):** 74

Other Nearby Industrial / Institutional Facilities: Hospital and other institutional facilities. Coal processing plant directly next to mine. Perfume/cosmetic chemical facility and men's footwear manufacturing plant to east in Delta Co

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 45
Updated: 05/09/2008

McClane Canyon Mine

GEOGRAPHIC DATA

Basin: Uinta

State: CO

Coalbed: Cameo Seam

County: Garfield

CORPORATE INFORMATION

Current Operator: McClane Canyon Mining LLC

Owner/Parent Company: Wexford Capital LLC

Parent Company Web Site: NA

Previous Owner(s): CAM Mining LLC

Previous or Alternate Name of Mine: NA

MINE ADDRESS

Contact Name: Mark Wayment

Phone Number: (435) 448-9454

Mailing Address: 3148 Hwy 139

City: Loma **State:** CO **ZIP:** 81524

GENERAL INFORMATION

Number of Employees at Mine: 26

Mining Method: Continuous

Year of Initial Production: 2005

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: 0.57%

Prep Plant Located on Site: No

BTUs/lb of Coal Produced: 11,522

Depth to Seam (ft): NA

Seam Thickness (ft): 13

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	-	-	-	0.3	0.3
Estimated Total Methane Liberated (million cf/day):	-	-	-	0.3	0.9
Emission from Ventilation Systems:	-	-	-	0.3	0.9
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	-	-	-	394	1300
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Mc Clane Canyon Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.030	0.06	0.091
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	4.9%	9.7%	14.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.1%	2.3%	3.4%

Power Generation Potential

Utility Electric Supplier: None

Transmission Line in County: Yes

Parent Corporation of Utility: NA

	MW	GWh/year
Total Electricity Demand (2006 data):	2.1	7.9
Mine Electricity Demand:	1.6	6.3
Prep Plant Electricity Demand:	0.4	1.6
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	0.7	6.2
Assuming 40% Recovery Efficiency:	1.4	12.4
Assuming 60% Recovery Efficiency:	2.1	18.7

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: NA

Transmission Pipeline in County? NA

Owner of Nearest Pipeline: NA

Distance to Pipeline (miles): NA

Pipeline Diameter (inches): NA

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA

Pipeline Diameter (inches): NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Bonanza

Distance to Plant (miles): 52

Other Nearby Industrial / Institutional Facilities: NA

Mine Status:	Active		
Drainage System:	Yes	**2006 Rank:**	3
Use Project:	Heaters	**Updated:**	05/09/2008

West Elk Mine

GEOGRAPHIC DATA

Basin: Uinta

State: CO

Coalbed: B Seam

County: Gunnison

CORPORATE INFORMATION

Current Operator: Mountain Coal Company

Owner/Parent Company: Arch Coal Inc

Parent Company Web Site: www.archcoal.com

Previous Owner(s): Atlantic Richfield/ITOCHU Corp

Previous or Alternate Name of Mine: Mt. Gunnison

MINE ADDRESS

Contact Name: Pete Wydcott, General Mgr.

Phone Number: (970) 929-5015

Mailing Address: PO Box 591

City: Somerset **State:** CO **ZIP:** 81434

GENERAL INFORMATION

Number of Employees at Mine: 394

Mining Method: Longwall

Year of Initial Production: 1982

Primary Coal Use: Steam

Life Expectancy: 2020

Sulfur Content of Coal Produced: 0.36% - 0.78%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 11,700

Depth to Seam (ft): 1,000 - 2,000

Seam Thickness (ft): 12.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	6.6	6.5	6.5	5.6	6.0
Estimated Total Methane Liberated (million cf/day):	19.8	27.2	20.9	22.7	18.2
Emission from Ventilation Systems:	9.9	13.6	10.4	11.4	9.1
Estimated Methane Drained:	9.9	13.6	10.5	11.4	9.1
Estimated Specific Emissions (cf/ton):	1100	1528	1175	1486	1107
Methane Used (million cf/day):	-	0.1	0.5	0.5	0.5

Estimated Current Drainage Efficiency: 50%

Estimated Current Market Penetration: 5%

Drainage System Used: Horizontal & Vertical Gob Boreholes with Pumps

West Elk Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.591	1.18	1.774
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	4.1%	8.2%	12.2%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.9%	1.9%	2.8%

Power Generation Potential

Utility Electric Supplier: Delta-Montrose Electric Association **Transmission Line in County:** Planned

Parent Corporation of Utility: Touchstone Energy Cooperatives

	MW	GWh/year
Total Electricity Demand (2006 data):	47.7	180.4
Mine Electricity Demand:	37.4	144.3
Prep Plant Electricity Demand:	10.2	36.1
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	13.8	121.0
Assuming 40% Recovery Efficiency:	27.6	241.9
Assuming 60% Recovery Efficiency:	41.4	362.9

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	1.3
Assuming 40% Recovery (Bcf):	2.7
Assuming 60% Recovery (Bcf):	4.0

Description of Surrounding Terrain: Hilly/Mountainous

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Kinder Morgan Inc

Distance to Pipeline (miles): 9.5 **Pipeline Diameter (inches):** 4.0

Owner of Next Nearest Pipeline: Rocky Mountain Natural Gas

Distance to Next Nearest Pipeline (miles): 26.0 **Pipeline Diameter (inches):** 6.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Nucla **Distance to Plant (miles):** 73

Other Nearby Industrial / Institutional Facilities: Hospital and other institutional facilities. Coal processing plant directly next to mine. Perfume/cosmetic chemical facility and men's footwear manufacturing plant to east in Delta Co

6. Profiled Mines (continued)

Illinois Mines

Galatia
Pattiki
Wabash
Willow Lake Portal

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 5
Updated: 05/09/2008

Galatia

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Springfield No. 5

County: Saline

CORPORATE INFORMATION

Current Operator: The American Coal Company

Owner/Parent Company: Murray Energy Corp

Parent Company Web Site: NA

Previous Owner(s): Kerr-McGee Coal Corp

Previous or Alternate Name of Mine: Galatia No. 56

MINE ADDRESS

Contact Name: Randy Wiles, General Mgr.

Phone Number: (618) 268-6444

Mailing Address: PO Box 727

City: Harrisburg **State:** IL **ZIP:** 62946

GENERAL INFORMATION

Number of Employees at Mine: 892

Mining Method: Longwall

Year of Initial Production: 1983

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: 0.73% - 1.5%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 12,150

Depth to Seam (ft): 600-830

Seam Thickness (ft): 5.0 - 6.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	6.3	6.0	6.5	5.9	7.2
Estimated Total Methane Liberated (million cf/day):	6.1	3.9	5.6	7.5	8.5
Emission from Ventilation Systems:	6.1	3.9	5.6	7.5	8.5
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	354	238	315	464	429
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Galatia (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2006 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.275	0.55	0.824
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.5%	3.1%	4.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.4%	0.7%	1.1%

Power Generation Potential

Utility Electric Supplier: Central Illinois Public Services Co **Transmission Line in County:** Yes

Parent Corporation of Utility: Ameren Corp

	MW	GWh/year
Total Electricity Demand (2006 data):	57.2	216.4
Mine Electricity Demand:	44.9	173.1
Prep Plant Electricity Demand:	12.3	43.3
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	6.4	56.2
Assuming 40% Recovery Efficiency:	12.8	112.4
Assuming 60% Recovery Efficiency:	19.3	168.7

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.6
Assuming 40% Recovery (Bcf):	1.2
Assuming 60% Recovery (Bcf):	1.9

Description of Surrounding Terrain: Open Hills/Irregular Plains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Unities Cities Gas Co

Distance to Pipeline (miles): 0.1 **Pipeline Diameter (inches):** 3.0

Owner of Next Nearest Pipeline: Spectra Energy Corp

Distance to Next Nearest Pipeline (miles): 1.1 **Pipeline Diameter (inches):** 24.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Joppa Steam **Distance to Plant (miles):** 45

Other Nearby Industrial / Institutional Facilities: Apparel, fertilizers, trusses, and mine equipment manufacturing, newspaper publishing, cosmetics, agricultural chemicals

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 31
Updated: 05/09/2008

Pattiki Mine

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Herrin No. 6

County: White

CORPORATE INFORMATION

Current Operator: White County Coal LLC

Owner/Parent Company: Alliance Resource Partners LP

Parent Company Web Site: www.arlp.com

Previous Owner(s): MAPCO Coal Inc

Previous or Alternate Name of Mine: Galatia Mine No. 56-1

MINE ADDRESS

Contact Name: Mark Kitchen, Gen. Mine Foreman

Phone Number: (618) 382-4651

Mailing Address: PO Box 457

City: Carmi **State:** IL **ZIP:** 62821

GENERAL INFORMATION

Number of Employees at Mine: 304

Mining Method: Continuous

Year of Initial Production: 1985

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: 2.8%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 11,750

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	1.8	0.3	2.4	2.6	2.5
Estimated Total Methane Liberated (million cf/day):	1.9	0.7	1.1	1.7	2.0
Emission from Ventilation Systems:	1.9	0.6	1.1	1.7	2.0
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	371	704	167	238	297
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Pattiki Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2006 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.066	0.13	0.199
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.1%	2.2%	3.3%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.5%	0.8%

Power Generation Potential

Utility Electric Supplier: Wayne-White Counties Electric Coop **Transmission Line in County:** Yes

Parent Corporation of Utility: NA

	MW	GWh/year
Total Electricity Demand (2006 data):	19.9	75.2
Mine Electricity Demand:	15.6	60.1
Prep Plant Electricity Demand:	4.3	15.0
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	1.5	13.5
Assuming 40% Recovery Efficiency:	3.1	27.1
Assuming 60% Recovery Efficiency:	4.6	40.6

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.3
Assuming 60% Recovery (Bcf):	0.4

Description of Surrounding Terrain: Irregular Plains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Texas Eastern Transmission Co.

Distance to Pipeline (miles): 3.3 **Pipeline Diameter (inches):** 24.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Gibson **Distance to Plant (miles):** 28

Other Nearby Industrial / Institutional Facilities: Unknown

Mine Status: Active (Abandoned in 2007)
Drainage System: No
Use Project: None

2006 Rank: 30
Updated: 05/09/2008

Wabash

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Springfield No. 5

County: Wabash

CORPORATE INFORMATION

Current Operator: Wabash Mine Holding Company

Owner/Parent Company: Foundation Coal Corporation

Parent Company Web Site: www.foundationcoal.com

Previous Owner(s): RAG American Coal Co, Amax Coal Co

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: William Kelly, Gen. Mine Mgr.

Phone Number: (618) 298-2394

Mailing Address: PO Box 144, 1000 Beall Woods Dr

City: Keensburg **State:** IL **ZIP:** 62852

GENERAL INFORMATION

Number of Employees at Mine: 4

Mining Method: Continuous

Year of Initial Production: 1973

Primary Coal Use: Steam

Life Expectancy: 2007

Sulfur Content of Coal Produced: 1.5%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 11,000

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	1.5	1.6	1.7	1.7	1.2
Estimated Total Methane Liberated (million cf/day):	0.8	1.2	2.0	1.6	2.1
Emission from Ventilation Systems:	0.8	1.2	2.0	1.6	2.1
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	189	280	438	333	639
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Wabash (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.067	0.13	0.200
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	2.5%	5.1%	7.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.6%	1.2%	1.7%

Power Generation Potential

Utility Electric Supplier: Wayne-White Counties Electric Coop **Transmission Line in County:** Yes

Parent Corporation of Utility: NA

	MW	GWh/year
Total Electricity Demand (2006 data):	9.3	35.3
Mine Electricity Demand:	7.3	28.2
Prep Plant Electricity Demand:	2.0	7.1
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	1.6	13.6
Assuming 40% Recovery Efficiency:	3.1	27.3
Assuming 60% Recovery Efficiency:	4.7	40.9

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.2
Assuming 40% Recovery (Bcf):	0.3
Assuming 60% Recovery (Bcf):	0.5

Description of Surrounding Terrain: Irregular Plains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Mt. Carmel Public Utility Co

Distance to Pipeline (miles): 0.85 **Pipeline Diameter (inches):** 6.0

Owner of Next Nearest Pipeline: Community Natural Gas

Distance to Next Nearest Pipeline (miles): 6.0 **Pipeline Diameter (inches):** 3.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Gibson **Distance to Plant (miles):** 4.6

Other Nearby Industrial / Institutional Facilities: Some General Manufacturing including car parts, boxes, electrical; also a Steel fabrication plant and a fertilizer chemical mixing company

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 43
Updated: 05/09/2008

Willow Lake Portal

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Illinois No. 5 & 6

County: Saline

CORPORATE INFORMATION

Current Operator: Big Ridge Inc

Owner/Parent Company: Peabody Energy Corp

Parent Company Web Site: www.peabodyenergy.com

Previous Owner(s): Arclar Co LLC

Previous or Alternate Name of Mine: Willow Lake Mine

MINE ADDRESS

Contact Name: Vic Daiber, Mine Engineer

Phone Number: (618) 273-4314

Mailing Address: 420 Long Lane Rd

City: Equality **State:** IL **ZIP:** 62934

GENERAL INFORMATION

Number of Employees at Mine: 405

Mining Method: Continuous

Year of Initial Production: 2002

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: 2.8%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 12,100

Depth to Seam (ft): NA

Seam Thickness (ft): 4.5 - 5.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	2.1	2.9	3.4	3.7	3.6
Estimated Total Methane Liberated (million cf/day):	0.5	1.1	1.3	1.2	1.0
Emission from Ventilation Systems:	0.5	1.1	1.3	1.2	1.0
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	86	138	140	118	102
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Willow Lake Portal (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.033	0.06	0.099
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.4%	0.7%	1.1%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.2%	0.3%

Power Generation Potential

Utility Electric Supplier: Southeastern Illinois Electric Coop Inc **Transmission Line in County:** Yes

Parent Corporation of Utility: Touchstone Energy Cooperatives

	MW	GWh/year
Total Electricity Demand (2006 data):	28.8	109.2
Mine Electricity Demand:	22.6	87.3
Prep Plant Electricity Demand:	6.2	21.8
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	0.8	6.7
Assuming 40% Recovery Efficiency:	1.5	13.5
Assuming 60% Recovery Efficiency:	2.3	20.2

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: NA

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Egyptian Gas Storage Co

Distance to Pipeline (miles): 2.4 **Pipeline Diameter (inches):** 2.0

Owner of Next Nearest Pipeline: United Cities Gas Co

Distance to Next Nearest Pipeline (miles): 5.0 **Pipeline Diameter (inches):** 2.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Joppa Steam **Distance to Plant (miles):** 45

Other Nearby Industrial / Institutional Facilities: Chemical: fertilizer, soaps, explosives; General manufacturing: apparel, rubber, concrete

6. Profiled Mines (continued)

Indiana Mines

Gibson

Mine Status:	Active		
Drainage System:	No	**2006 Rank:**	26
Use Project:	None	**Updated:**	05/09/2008

Gibson

GEOGRAPHIC DATA

Basin: Illinois

State: IN

Coalbed: Springfield No. 5

County: Gibson

CORPORATE INFORMATION

Current Operator: Gibson County Coal LLC

Owner/Parent Company: Alliance Resource Partners LP

Parent Company Web Site: www.arlp.com

Previous Owner(s): Alliance Resources Holdings

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Maynard St. John, General Mgr.

Phone Number: (812) 385-1816

Mailing Address: 1269 Lyle Station Rd

City: Princeton **State:** IN **ZIP:** 47670

GENERAL INFORMATION

Number of Employees at Mine: 272

Mining Method: Continuous

Year of Initial Production: 2000

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: 0.84% - 1.75%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 11,325

Depth to Seam (ft): NA

Seam Thickness (ft): 0.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	1.9	2.4	3.0	3.4	3.6
Estimated Total Methane Liberated (million cf/day):	2.1	2.4	2.2	2.6	3.1
Emission from Ventilation Systems:	2.2	2.4	2.2	2.6	3.1
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	406	355	264	279	313
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Gibson (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.100	0.19	0.299
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.2%	2.4%	3.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.6%	0.8%

Power Generation Potential

Utility Electric Supplier: Duke Energy Indiana Inc

Transmission Line in County: Yes

Parent Corporation of Utility: Duke Energy Corp

	MW	GWh/year
Total Electricity Demand (2006 data):	28.3	107.2
Mine Electricity Demand:	22.2	85.8
Prep Plant Electricity Demand:	6.1	21.4
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	2.3	20.4
Assuming 40% Recovery Efficiency:	4.6	40.7
Assuming 60% Recovery Efficiency:	7.0	61.1

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.2
Assuming 40% Recovery (Bcf):	0.4
Assuming 60% Recovery (Bcf):	0.7

Description of Surrounding Terrain: NA

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Vectren Corporation

Distance to Pipeline (miles): 0.7

Pipeline Diameter (inches): 6.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA

Pipeline Diameter (inches): NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Gibson

Distance to Plant (miles): 9

Other Nearby Industrial / Institutional Facilities: General manufacturing including electronic assembly, animal food, motor and generator, metal, plastics, tires; one chemical plant

6. Profiled Mines (continued)

Kentucky Mines

Dotiki
E3-1
Jones Fork E-3
Mine No. 2
No. 3 Mine

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 47
Updated: 05/09/2008

Dotiki Mine

GEOGRAPHIC DATA

Basin: Illinois

State: KY

Coalbed: W. KY No. 9

County: Hopkins

CORPORATE INFORMATION

Current Operator: Webster County Coal LLC

Owner/Parent Company: Alliance Resource Partners LP

Parent Company Web Site: www.arlp.com

Previous Owner(s): None in last 10 years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: James F. Martin, Gen. Mine Foreman

Phone Number: (270) 249-2205

Mailing Address: 1586 Balls Hill Rd

City: Nebo **State:** KY **ZIP:** 42441

GENERAL INFORMATION

Number of Employees at Mine: 430

Mining Method: Continuous

Year of Initial Production: 1967

Primary Coal Use: Steam

Life Expectancy: 2015

Sulfur Content of Coal Produced: 2.85% - 3.1%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 12,400

Depth to Seam (ft): 700

Seam Thickness (ft): 4.8

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	4.5	4.9	4.8	4.7	4.7
Estimated Total Methane Liberated (million cf/day):	0.5	0.5	0.6	0.7	0.9
Emission from Ventilation Systems:	0.5	0.5	0.6	0.7	0.9
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	41	34	46	55	71
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Dotiki Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.030	0.05	0.089
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.2%	0.5%	0.7%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.1%	0.2%

Power Generation Potential

Utility Electric Supplier: Kentucky Utilities Co **Transmission Line in County:** Yes

Parent Corporation of Utility: E.ON AG

	MW	GWh/year
Total Electricity Demand (2006 data):	37.5	142.0
Mine Electricity Demand:	29.5	113.6
Prep Plant Electricity Demand:	8.1	28.4
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	0.7	6.1
Assuming 40% Recovery Efficiency:	1.4	12.2
Assuming 60% Recovery Efficiency:	2.1	18.2

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: NA

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Loews Corporation

Distance to Pipeline (miles): 5.5 **Pipeline Diameter (inches):** 26.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Paradise **Distance to Plant (miles):** 40

Other Nearby Industrial / Institutional Facilities: General manufacturing including mining machinery, plastic containers, apparel, metal roofing; Steel fabrication; one chemical (soap and detergent) plant

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 49
Updated: 05/09/2008

E3-1

GEOGRAPHIC DATA

Basin: Central Appalachian

State: KY

Coalbed: Hazard 4 / Elkhorn 3

County: Perry

CORPORATE INFORMATION

Current Operator: Perry County Coal Corp

Owner/Parent Company: Teco Coal Co

Parent Company Web Site: www.tecocoal.com

Previous Owner(s): None

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Craig Mullins, Dir. Of Operations

Phone Number: (606) 523-4444

Mailing Address: 1845 S KY Hwy 15

City: Hazard **State:** KY **ZIP:** 41701

GENERAL INFORMATION

Number of Employees at Mine: 144

Mining Method: Continuous

Year of Initial Production: 2005

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: 1.2%

Prep Plant Located on Site: No

BTUs/lb of Coal Produced: 14,662

Depth to Seam (ft): NA

Seam Thickness (ft): 4.2

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	-	-	-	0.5	1.1
Estimated Total Methane Liberated (million cf/day):	-	-	-	0.2	0.9
Emission from Ventilation Systems:	-	-	-	0.5	0.9
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	-	-	-	102	298
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

E3-1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.028	0.05	0.084
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.9%	1.8%	2.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.4%	0.6%

Power Generation Potential

Utility Electric Supplier: Kentucky Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: American Electric Power Co Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	8.4	31.9
Mine Electricity Demand:	6.6	25.5
Prep Plant Electricity Demand:	1.8	6.4
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	0.7	5.8
Assuming 40% Recovery Efficiency:	1.3	11.5
Assuming 60% Recovery Efficiency:	2.0	17.3

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: NA

Transmission Pipeline in County? NA

Owner of Nearest Pipeline: NA

Distance to Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Kentucky Mountain Power (Planned) **Distance to Plant (miles):** NA

Other Nearby Industrial / Institutional Facilities: NA

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 41
Updated: 05/09/2008

Jones Fork E-3

GEOGRAPHIC DATA

Basin: Central Appalachian

State: KY

Coalbed: Hazard 4 / Elkhorn 3

County: Knott

CORPORATE INFORMATION

Current Operator: Consol of Kentucky Inc

Owner/Parent Company: CONSOL Energy Inc

Parent Company Web Site: www.consolenergy.com

Previous Owner(s): None

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Thomas F. Hoffman, VP

Phone Number: (412) 831-4000

Mailing Address: 1800 Washington Rd

City: Pittsburgh **State:** PA **ZIP:** 15241

GENERAL INFORMATION

Number of Employees at Mine: 129

Mining Method: Continuous

Year of Initial Production: 2004

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: 0.5% - 4.1%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 13,000

Depth to Seam (ft): NA

Seam Thickness (ft): 5.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	-	-	2.2	2.2	1.8
Estimated Total Methane Liberated (million cf/day):	-	-	1.1	0.4	1.1
Emission from Ventilation Systems:	-	-	1.1	1.1	1.1
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	-	-	186	64	221
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Jones Fork E-3 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	20%	40%	60%
	Assumed Potential Recovery Efficiency		
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.036	0.07	0.108
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.7%	1.5%	2.2%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.3%	0.5%

Power Generation Potential

Utility Electric Supplier: Kentucky Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: American Electric Power Co Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	14.6	55.3
Mine Electricity Demand:	11.5	44.2
Prep Plant Electricity Demand:	3.1	11.1
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	0.8	7.4
Assuming 40% Recovery Efficiency:	1.7	14.8
Assuming 60% Recovery Efficiency:	2.5	22.2

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: NA

Transmission Pipeline in County? NA

Owner of Nearest Pipeline: NA

Distance to Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Kentucky Mountain Power (Planned) **Distance to Plant (miles):** NA

Other Nearby Industrial / Institutional Facilities: NA

Mine Status:	Active		
Drainage System:	No	**2006 Rank:**	42
Use Project:	None	**Updated:**	05/09/2008

Mine No. 2

GEOGRAPHIC DATA

Basin: Central Appalachian

State: KY

Coalbed: Pond Creek

County: Martin

CORPORATE INFORMATION

Current Operator: Excel Mining LLC

Owner/Parent Company: Alliance Resource Partners LP

Parent Company Web Site: www.arlp.com

Previous Owner(s): Pontiki Coal Corp

Previous or Alternate Name of Mine: Pontiki No.2

MINE ADDRESS

Contact Name: John Small

Phone Number: (606) 395-5352

Mailing Address: PO Box 802

City: Lovely **State:** KY **ZIP:** 41231

GENERAL INFORMATION

Number of Employees at Mine: 120

Mining Method: Continuous

Year of Initial Production: 1990

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: 0.6% - 0.73%

Prep Plant Located on Site: No

BTUs/lb of Coal Produced: 12,900

Depth to Seam (ft): 425

Seam Thickness (ft): 4.2

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	1.8	2.0	1.7	1.6	0.8
Estimated Total Methane Liberated (million cf/day):	0.4	0.7	0.7	0.7	1.1
Emission from Ventilation Systems:	0.4	0.7	0.7	0.7	1.1
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	83	132	155	153	457
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Mine No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.034	0.06	0.102
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.5%	3.1%	4.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.4%	0.7%	1.1%

Power Generation Potential

Utility Electric Supplier: Kentucky Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: American Electric Power Co Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	6.7	25.2
Mine Electricity Demand:	5.2	20.1
Prep Plant Electricity Demand:	1.4	5.0
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	0.8	7.0
Assuming 40% Recovery Efficiency:	1.6	13.9
Assuming 60% Recovery Efficiency:	2.4	20.9

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: High Hills/Low Mountains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Kentucky West Virginia Gas Co

Distance to Pipeline (miles): <0.1 **Pipeline Diameter (inches):** 7.0

Owner of Next Nearest Pipeline: NiSource

Distance to Next Nearest Pipeline (miles): 2.0 **Pipeline Diameter (inches):** 6.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Big Sandy **Distance to Plant (miles):** 38

Other Nearby Industrial / Institutional Facilities: Misc. general manufacturing - only one < 10 mi, general machining

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 37
Updated: 05/09/2008

No. 3 Mine

GEOGRAPHIC DATA

Basin: Central Appalachian

State: KY

Coalbed: Pond Creek / Van Lear

County: Pike

CORPORATE INFORMATION

Current Operator: Excel Mining LLC

Owner/Parent Company: Alliance Resource Partners LP

Parent Company Web Site: www.arlp.com

Previous Owner(s): Garrett Mining Inc

Previous or Alternate Name of Mine: Pontiki No.3

MINE ADDRESS

Contact Name: Judy Magee

Phone Number: (918) 295-7635

Mailing Address: 4126 St Hwy 194 W

City: Pikeville **State:** KY **ZIP:** 41501

GENERAL INFORMATION

Number of Employees at Mine: 257

Mining Method: Continuous

Year of Initial Production: 1977

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: 0.8% - 1.4%

Prep Plant Located on Site: No

BTUs/lb of Coal Produced: 13,440

Depth to Seam (ft): NA

Seam Thickness (ft): 4.3

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	1.3	1.5	2.0	1.6	1.9
Estimated Total Methane Liberated (million cf/day):	0.8	0.9	1.4	1.5	1.3
Emission from Ventilation Systems:	0.8	0.9	1.4	1.5	1.3
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	228	216	262	337	262
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

No. 3 Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.044	0.08	0.131
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.8%	1.7%	2.5%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.4%	0.6%

Power Generation Potential

Utility Electric Supplier: Kentucky Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: American Electric Power Co Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	14.8	56.2
Mine Electricity Demand:	11.7	44.9
Prep Plant Electricity Demand:	3.2	11.2
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	1.0	8.9
Assuming 40% Recovery Efficiency:	2.0	17.8
Assuming 60% Recovery Efficiency:	3.1	26.7

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.3

Description of Surrounding Terrain: NA

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Kentucky West Virginia Gas Co

Distance to Pipeline (miles): <0.1 **Pipeline Diameter (inches):** 12.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Big Sandy **Distance to Plant (miles):** 41

Other Nearby Industrial / Institutional Facilities: Only a handful of general manufacturing plants within 10 miles, including petroleum and coal products manufacturing, toaster pastries, and general machining

New Mexico Mines

San Juan South

Mine Status: Active
Drainage System: Yes
Use Project: None

2006 Rank: 22
Updated: 05/09/2008

San Juan South

GEOGRAPHIC DATA

Basin: San Juan

State: NM

Coalbed: No. 9 / No. 8

County: San Juan

CORPORATE INFORMATION

Current Operator: San Juan Coal Company

Owner/Parent Company: BHP Billiton

Parent Company Web Site: www.bhpbilliton.com

Previous Owner(s): None in last 10 years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Chris Ellefson, VP & GM

Phone Number: (505) 598-2000

Mailing Address: PO Box 561

City: Waterflow **State:** NM **ZIP:** 87421

GENERAL INFORMATION

Number of Employees at Mine: 468

Mining Method: Longwall

Year of Initial Production: 1997

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: 0.8%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 9,500

Depth to Seam (ft): 400 - 900

Seam Thickness (ft): 10.0 - 13.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	1.8	5.9	7.7	7.9	7.0
Estimated Total Methane Liberated (million cf/day):	2.0	3.6	4.1	6.4	6.5
Emission from Ventilation Systems:	1.5	1.3	1.6	3.9	3.9
Estimated Methane Drained:	0.5	2.3	2.5	2.6	2.6
Estimated Specific Emissions (cf/ton):	426	223	196	298	340
Methane Used (million cf/day):	-	0.0	0.2	0.0	-

Estimated Current Drainage Efficiency: 40%

Estimated Current Market Penetration: 0%

Drainage System Used: Vertical Gob Boreholes; Horizontal Pre-Mine Boreholes

San Juan South (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2006 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.211	0.42	0.634
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.5%	3.1%	4.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.4%	0.7%	1.1%

Power Generation Potential

Utility Electric Supplier: Jemez Mountains Electric Coop Inc **Transmission Line in County:** Yes

Parent Corporation of Utility: NA

	MW	GWh/year
Total Electricity Demand (2006 data):	55.4	209.8
Mine Electricity Demand:	43.5	167.8
Prep Plant Electricity Demand:	11.9	42.0
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	4.9	43.2
Assuming 40% Recovery Efficiency:	9.9	86.5
Assuming 60% Recovery Efficiency:	14.8	129.7

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.5
Assuming 40% Recovery (Bcf):	1.0
Assuming 60% Recovery (Bcf):	1.4

Description of Surrounding Terrain: NA

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Western Gas Resources Inc

Distance to Pipeline (miles): 1.3 **Pipeline Diameter (inches):** 6.0

Owner of Next Nearest Pipeline: Western Chuska Line

Distance to Next Nearest Pipeline (miles): 1.5 **Pipeline Diameter (inches):** 16.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: San Juan **Distance to Plant (miles):** 1.8

Other Nearby Industrial / Institutional Facilities: Only plant within 10 miles is a cleaning product manufacturing co., some misc. general manufacturing to east ~15 mi including general machining, concrete, wellhead, septic tanks, newspaper publishing, and blood plasma

6. Profiled Mines (continued)

Ohio Mines

Century
Powhatan No. 6

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 34
Updated: 05/09/2008

Century Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: OH

Coalbed: Pittsburgh No. 8

County: Belmont

CORPORATE INFORMATION

Current Operator: American Energy Corporation

Owner/Parent Company: Murray Energy Corp

Parent Company Web Site: NA

Previous Owner(s): Youghiogheny and Ohio Coal Company

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Ryan M. Murray, Mine Mgr. & Superintendent

Phone Number: (740) 795-5220

Mailing Address: 43521 Mayhugh Hill Rd

City: Beallsville **State:** OH **ZIP:** 43716

GENERAL INFORMATION

Number of Employees at Mine: 416

Mining Method: Longwall

Year of Initial Production: 2001

Primary Coal Use: Steam

Life Expectancy: 2037

Sulfur Content of Coal Produced: 3.8% - 4.5%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 12,600

Depth to Seam (ft): 500

Seam Thickness (ft): 5.3

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	3.4	4.6	5.8	6.6	6.5
Estimated Total Methane Liberated (million cf/day):	0.5	0.6	1.2	1.6	1.9
Emission from Ventilation Systems:	0.5	0.6	1.2	1.6	1.9
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	52	45	75	89	105
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Century Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.060	0.12	0.180
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.4%	0.7%	1.1%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.2%	0.2%

Power Generation Potential

Utility Electric Supplier: South Central Power Co

Transmission Line in County: Yes

Parent Corporation of Utility: Touchstone Energy Cooperatives

	MW	GWh/year
Total Electricity Demand (2006 data):	51.1	193.5
Mine Electricity Demand:	40.1	154.8
Prep Plant Electricity Demand:	11.0	38.7
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	1.4	12.3
Assuming 40% Recovery Efficiency:	2.8	24.6
Assuming 60% Recovery Efficiency:	4.2	36.9

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.3
Assuming 60% Recovery (Bcf):	0.4

Description of Surrounding Terrain: NA

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: NiSource

Distance to Pipeline (miles): 3.5 **Pipeline Diameter (inches):** 8.0

Owner of Next Nearest Pipeline: NiSource

Distance to Next Nearest Pipeline (miles): 4.0 **Pipeline Diameter (inches):** 6.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Mitchell **Distance to Plant (miles):** 12

Other Nearby Industrial / Institutional Facilities: Handful of general manufacturing including coal processing, paints, wooden toys

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 33
Updated: 05/09/2008

Powhatan No. 6 Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian
State: OH
Coalbed: Pittsburgh No. 8
County: Belmont

CORPORATE INFORMATION

Current Operator: Ohio Valley Coal Company

Owner/Parent Company: Murray Energy Corp
Parent Company Web Site: www.ohiovalleycoal.com
Previous Owner(s): Nacco Mining Company
Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Roy A. Heidelbach, Mine Supt.
Phone Number: (740) 926-1351
Mailing Address: 56854 Pleasant Ridge Rd
City: Alledonia **State:** OH **ZIP:** 43902

GENERAL INFORMATION

Number of Employees at Mine: 467
Mining Method: Longwall
Year of Initial Production: 1972
Primary Coal Use: Steam
Life Expectancy: 2018
Sulfur Content of Coal Produced: 3.8% - 4.5%
Prep Plant Located on Site: Yes
BTUs/lb of Coal Produced: 12,600
Depth to Seam (ft): 400 - 600
Seam Thickness (ft): 5.3

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	3.9	4.9	4.5	5.3	4.4
Estimated Total Methane Liberated (million cf/day):	1.2	1.1	1.6	1.7	2.0
Emission from Ventilation Systems:	1.2	1.1	1.6	1.7	2.0
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	116	85	129	119	167
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA
Estimated Current Market Penetration: NA
Drainage System Used: None

Powhatan No. 6 Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.065	0.13	0.195
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.6%	1.2%	1.7%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.3%	0.4%

Power Generation Potential

Utility Electric Supplier: South Central Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: Touchstone Energy Cooperatives

	MW	GWh/year
Total Electricity Demand (2006 data):	34.6	131.1
Mine Electricity Demand:	27.2	104.9
Prep Plant Electricity Demand:	7.4	26.2
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	1.5	13.3
Assuming 40% Recovery Efficiency:	3.0	26.6
Assuming 60% Recovery Efficiency:	4.6	39.9

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.3
Assuming 60% Recovery (Bcf):	0.4

Description of Surrounding Terrain: Hills/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: NiSource

Distance to Pipeline (miles): 1.2 **Pipeline Diameter (inches):** 8.0

Owner of Next Nearest Pipeline: East Ohio Gas Co

Distance to Next Nearest Pipeline (miles): 3.0 **Pipeline Diameter (inches):** 20.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Mitchell **Distance to Plant (miles):** 11

Other Nearby Industrial / Institutional Facilities: Handful of general manufacturing including coal processing, paints, wooden toys

Oklahoma Mines

South Central

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 48
Updated: 05/09/2008

South Central Mine

GEOGRAPHIC DATA

Basin: Arkoma

State: OK

Coalbed: Hartshorne

County: Le Flore

CORPORATE INFORMATION

Current Operator: South Central Coal Company Inc

Owner/Parent Company: South Central Coal Company

Parent Company Web Site: NA

Previous Owner(s): Sunrise Coal Company

Previous or Alternate Name of Mine: Sunrise Coal; Pollyanna No. 8

MINE ADDRESS

Contact Name: Bobby G Meadows Jr

Phone Number: (918) 962-2544

Mailing Address: 22279 US Hwy 271

City: Spiro **State:** OK **ZIP:** 74959

GENERAL INFORMATION

Number of Employees at Mine: 55

Mining Method: Continuous

Year of Initial Production: 1995

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: 1.0%

Prep Plant Located on Site: No

BTUs/lb of Coal Produced: 14,190

Depth to Seam (ft): NA

Seam Thickness (ft): 5.75

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	0.5	0.4	0.4	0.5	0.4
Estimated Total Methane Liberated (million cf/day):	1.2	1.0	1.5	1.6	0.9
Emission from Ventilation Systems:	1.2	1.0	1.5	1.6	0.9
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	942	932	1348	1232	735
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

South Central Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.029	0.05	0.088
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	2.2%	4.5%	6.7%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.5%	1.0%	1.6%

Power Generation Potential

Utility Electric Supplier: Oklahoma Gas & Electric **Transmission Line in County:** Yes

Parent Corporation of Utility: OGE Energy Corp

	MW	GWh/year
Total Electricity Demand (2006 data):	3.6	13.5
Mine Electricity Demand:	2.8	10.8
Prep Plant Electricity Demand:	0.8	2.7
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	0.7	6.0
Assuming 40% Recovery Efficiency:	1.4	12.0
Assuming 60% Recovery Efficiency:	2.1	18.0

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: NA

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: CenterPoint Energy

Distance to Pipeline (miles): 0.75 **Pipeline Diameter (inches):** 6.0

Owner of Next Nearest Pipeline: CenterPoint Energy

Distance to Next Nearest Pipeline (miles): 1.4 **Pipeline Diameter (inches):** 4.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: AES Shady Point **Distance to Plant (miles):** 30

Other Nearby Industrial / Institutional Facilities: Some general manufacturing including metal (closest plant, <2 mi), newspaper, bakery goods, plastics

6. Profiled Mines (continued)

Pennsylvania Mines

Bailey
Cumberland
Eighty-Four Mine
Emerald
Enlow Fork

Mine Status:	Active			
Drainage System:	Yes		**2006 Rank:**	7
Use Project:	None		**Updated:**	05/09/2008

Bailey Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: PA

Coalbed: Pittsburgh No. 8

County: Greene

CORPORATE INFORMATION

Current Operator: Consol Pennsylvania Coal Company

Owner/Parent Company: CONSOL Energy Inc

Parent Company Web Site: www.consolenergy.com

Previous Owner(s): None in last 10 years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Roy Pride

Phone Number: (724) 428-1200

Mailing Address: 192 Crabapple Rd

City: Wind Ridge **State:** PA **ZIP:** 15377

GENERAL INFORMATION

Number of Employees at Mine: 659

Mining Method: Longwall

Year of Initial Production: 1984

Primary Coal Use: Steam, Metallurgical

Life Expectancy: NA

Sulfur Content of Coal Produced: 1.03% -2.41%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 13,200

Depth to Seam (ft): 600 - 1000

Seam Thickness (ft): 5.2 - 6.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	9.7	9.4	10.1	11.1	10.2
Estimated Total Methane Liberated (million cf/day):	7.1	5.7	8.4	9.8	10.7
Emission from Ventilation Systems:	7.1	5.7	8.4	6.9	7.5
Estimated Methane Drained:	0.1	-	-	2.9	3.2
Estimated Specific Emissions (cf/ton):	270	223	304	324	383
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 30%

Estimated Current Market Penetration: 0%

Drainage System Used: Vertical Gob Boreholes with Pumps

Bailey Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.346	0.69	1.038
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.3%	2.5%	3.8%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.6%	0.9%

Power Generation Potential

Utility Electric Supplier: West Penn Power Co

Transmission Line in County: Yes

Parent Corporation of Utility: Allegheny Energy Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	80.7	305.3
Mine Electricity Demand:	63.3	244.2
Prep Plant Electricity Demand:	17.3	61.1
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	8.1	70.8
Assuming 40% Recovery Efficiency:	16.2	141.6
Assuming 60% Recovery Efficiency:	24.2	212.4

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.8
Assuming 40% Recovery (Bcf):	1.6
Assuming 60% Recovery (Bcf):	2.3

Description of Surrounding Terrain: High Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: National Fuel Gas Supply Corp

Distance to Pipeline (miles): <0.1 **Pipeline Diameter (inches):** 20.0

Owner of Next Nearest Pipeline: NiSource

Distance to Next Nearest Pipeline (miles): 2.3 **Pipeline Diameter (inches):** 12.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Mitchell **Distance to Plant (miles):** 20

Other Nearby Industrial / Institutional Facilities: Television components, apparel, and metal manufacturing; hospitals, schools and other municipal buildings

Mine Status: Active
Drainage System: Yes
Use Project: Pipeline

2006 Rank: 10
Updated: 05/09/2008

Cumberland

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: PA

Coalbed: Pittsburgh No. 8

County: Greene

CORPORATE INFORMATION

Current Operator: Cumberland Coal Resources LP

Owner/Parent Company: Foundation Coal Corporation

Parent Company Web Site: www.foundationcoal.com

Previous Owner(s): Cyprus Coal Resources Corp;
U.S. Steel Mining Comp

Previous or Alternate Name of Mine: RAG Cumberland

MINE ADDRESS

Contact Name: Mike Mishra, Pres.

Phone Number: (724) 852-6272

Mailing Address: PO Box 1020

City: Waynesburg

State: PA

ZIP: 15370

GENERAL INFORMATION

Number of Employees at Mine: 676

Mining Method: Longwall

Year of Initial Production: 1972

Primary Coal Use: Steam

Life Expectancy: 2023

Sulfur Content of Coal Produced: 2.4%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 13,000

Depth to Seam (ft): 400 - 1000

Seam Thickness (ft): 6.5 - 7.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	6.6	6.2	5.2	7.1	7.5
Estimated Total Methane Liberated (million cf/day):	11.1	14.3	10.7	10.8	10.1
Emission from Ventilation Systems:	9.6	9.9	7.2	7.2	6.7
Estimated Methane Drained:	1.5	4.4	3.4	3.7	3.4
Estimated Specific Emissions (cf/ton):	609	833	750	557	491
Methane Used (million cf/day):	-	-	-	3.2	3.4

Estimated Current Drainage Efficiency: 34%

Estimated Current Market Penetration: 100%

Drainage System Used: Vertical Gob Boreholes with Pumps

Cumberland (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.328	0.65	0.983
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.6%	3.3%	4.9%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.4%	0.8%	1.1%

Power Generation Potential

Utility Electric Supplier: West Penn Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: Allegheny Energy Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	59.6	225.5
Mine Electricity Demand:	46.8	180.4
Prep Plant Electricity Demand:	12.8	45.1
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	7.7	67.0
Assuming 40% Recovery Efficiency:	15.3	134.1
Assuming 60% Recovery Efficiency:	23.0	201.1

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.7
Assuming 40% Recovery (Bcf):	1.5
Assuming 60% Recovery (Bcf):	2.2

Description of Surrounding Terrain: High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Equitable Resources Inc

Distance to Pipeline (miles): 0.4 **Pipeline Diameter (inches):** 12.0

Owner of Next Nearest Pipeline: Equitable Resources Inc

Distance to Next Nearest Pipeline (miles): 0.4 **Pipeline Diameter (inches):** 16.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Hatfields Ferry **Distance to Plant (miles):** 12

Other Nearby Industrial / Institutional Facilities: Television components, apparel, and metal manufacturing; hospitals, schools and other municipal buildings. Coal processing plant adjacent to mine

Mine Status:	Active			
Drainage System:	No		**2006 Rank:**	18
Use Project:	None		**Updated:**	05/09/2008

Eighty-Four Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: PA

Coalbed: Pittsburgh No. 8

County: Washington

CORPORATE INFORMATION

Current Operator: Eighty-Four Mining Company

Owner/Parent Company: CONSOL Energy Inc

Parent Company Web Site: www.consolenergy.com

Previous Owner(s): Beth Energy Mines Inc

Previous or Alternate Name of Mine: Mine 84, Ellsworth or Livingston

MINE ADDRESS

Contact Name: Thomas F. Hoffman, VP

Phone Number: (724) 250-1577

Mailing Address: 1800 Washington Rd

City: Pittsburgh **State:** PA **ZIP:** 15241

GENERAL INFORMATION

Number of Employees at Mine: 416

Mining Method: Longwall

Year of Initial Production: 1983

Primary Coal Use: Steam, Metallurgical

Life Expectancy: NA

Sulfur Content of Coal Produced: 1.33% - 1.71%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 13,307

Depth to Seam (ft): 500 - 750

Seam Thickness (ft): 5.2 - 6.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	4.0	4.0	4.0	3.8	3.5
Estimated Total Methane Liberated (million cf/day):	4.9	5.1	5.4	5.1	5.1
Emission from Ventilation Systems:	4.9	5.1	5.4	5.1	5.1
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	445	467	498	488	532
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Eighty-Four Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.166	0.33	0.498
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.7%	3.5%	5.2%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.4%	0.8%	1.2%

Power Generation Potential

Utility Electric Supplier: West Penn Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: Allegheny Energy Inc

	MW	**GWh/year**
Total Electricity Demand (2006 data):	27.8	105.2
Mine Electricity Demand:	21.8	84.1
Prep Plant Electricity Demand:	6.0	21.0
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	3.9	33.9
Assuming 40% Recovery Efficiency:	7.7	67.9
Assuming 60% Recovery Efficiency:	11.6	101.8

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.4
Assuming 40% Recovery (Bcf):	0.7
Assuming 60% Recovery (Bcf):	1.1

Description of Surrounding Terrain: Open High Hills/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Equitable Resources Inc

Distance to Pipeline (miles): 0.3 **Pipeline Diameter (inches):** 2.0

Owner of Next Nearest Pipeline: Equitable Resources Inc

Distance to Next Nearest Pipeline (miles): 1.0 **Pipeline Diameter (inches):** 20.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Mitchell Power Station **Distance to Plant (miles):** 7.7

Other Nearby Industrial / Institutional Facilities: Steel, plastics, apparel, glass, fertilizers, and other types of manufacturing; municipal buildings

Mine Status: Active
Drainage System: Yes
Use Project: Pipeline

2006 Rank: 16
Updated: 05/09/2008

Emerald

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: PA

Coalbed: Pittsburgh No. 8

County: Greene

CORPORATE INFORMATION

Current Operator: Emerald Coal Resources LP

Owner/Parent Company: Foundation Coal Corporation

Parent Company Web Site: www.foundationcoal.com

Previous Owner(s): Cyprus Emerald Resources Corp, Emerald Mines Corp

Previous or Alternate Name of Mine: RAG Emerald, Emerald No. 1

MINE ADDRESS

Contact Name: Mike Misha, Pres.

Phone Number: (724) 627-2278

Mailing Address: 158 Portal Rd, PO Box 1020

City: Waynesburg **State:** PA **ZIP:** 15370

GENERAL INFORMATION

Number of Employees at Mine: 634

Mining Method: Longwall

Year of Initial Production: 1977

Primary Coal Use: Steam, Metallurgical

Life Expectancy: 2013

Sulfur Content of Coal Produced: 2.4%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 13,000

Depth to Seam (ft): 400 - 1000

Seam Thickness (ft): 6.5 - 7.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	6.6	6.6	5.8	6.3	5.9
Estimated Total Methane Liberated (million cf/day):	9.1	9.5	7.2	6.8	7.4
Emission from Ventilation Systems:	6.6	7.4	4.9	4.7	5.2
Estimated Methane Drained:	2.5	2.0	2.3	2.0	2.3
Estimated Specific Emissions (cf/ton):	508	523	455	389	458
Methane Used (million cf/day):	-	-	-	1.8	2.3

Estimated Current Drainage Efficiency: 30%

Estimated Current Market Penetration: 100%

Drainage System Used: Vertical Gob Boreholes with Pumps

Emerald (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2006 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.241	0.48	0.724
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.5%	3.0%	4.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.4%	0.7%	1.1%

Power Generation Potential

Utility Electric Supplier: West Penn Power Co

Transmission Line in County: Yes

Parent Corporation of Utility: Allegheny Energy Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	46.9	177.7
Mine Electricity Demand:	36.9	142.1
Prep Plant Electricity Demand:	10.1	35.5
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	5.6	49.3
Assuming 40% Recovery Efficiency:	11.3	98.7
Assuming 60% Recovery Efficiency:	16.9	148.0

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.5
Assuming 40% Recovery (Bcf):	1.1
Assuming 60% Recovery (Bcf):	1.6

Description of Surrounding Terrain: High Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Equitable Resources Inc

Distance to Pipeline (miles): 0.23 **Pipeline Diameter (inches):** 20.0

Owner of Next Nearest Pipeline: Equitable Resources Inc

Distance to Next Nearest Pipeline (miles): 0.64 **Pipeline Diameter (inches):** 20.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Hatfields Ferry **Distance to Plant (miles):** 15

Other Nearby Industrial / Institutional Facilities: Television components, apparel, and metal manufacturing; hospitals, schools and other municipal buildings

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 2
Updated: 05/09/2008

Enlow Fork Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian
State: PA
Coalbed: Pittsburgh No. 8
County: Greene

CORPORATE INFORMATION

Current Operator: Consol Pennsylvania Coal Company

Owner/Parent Company: CONSOL Energy Inc
Parent Company Web Site: www.consolenergy.com
Previous Owner(s): None in last 10 years
Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Dave Hudson
Phone Number: (724) 663-3101
Mailing Address: Rte 231
City: East Finley
State: PA
ZIP: 15377

GENERAL INFORMATION

Number of Employees at Mine: 592
Mining Method: Longwall
Year of Initial Production: 1990
Primary Coal Use: Steam
Life Expectancy: NA
Sulfur Content of Coal Produced: 1.00% - 2.41%
Prep Plant Located on Site: No
BTUs/lb of Coal Produced: 13,000
Depth to Seam (ft): 600 - 1000
Seam Thickness (ft): 5.2 - 6.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	9.6	9.9	10.2	9.8	10.7
Estimated Total Methane Liberated (million cf/day):	9.1	10.3	11.0	9.6	10.1
Emission from Ventilation Systems:	9.0	10.3	11.0	9.6	10.1
Estimated Methane Drained:	0.1	-	-	-	-
Estimated Specific Emissions (cf/ton):	346	382	392	358	344
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA
Estimated Current Market Penetration: NA
Drainage System Used: None

Enlow Fork Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2006 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.327	0.65	0.982
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.1%	2.3%	3.4%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.5%	0.8%

Power Generation Potential

Utility Electric Supplier: West Penn Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: Allegheny Energy Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	84.9	321.1
Mine Electricity Demand:	66.6	256.9
Prep Plant Electricity Demand:	18.2	64.2
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	7.6	67.0
Assuming 40% Recovery Efficiency:	15.3	133.9
Assuming 60% Recovery Efficiency:	22.9	200.9

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.7
Assuming 40% Recovery (Bcf):	1.5
Assuming 60% Recovery (Bcf):	2.2

Description of Surrounding Terrain: Open Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: National Fuel Gas Supply Corp

Distance to Pipeline (miles): 1.2 **Pipeline Diameter (inches):** 20.0

Owner of Next Nearest Pipeline: NiSource

Distance to Next Nearest Pipeline (miles): 1.9 **Pipeline Diameter (inches):** 8.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Burger **Distance to Plant (miles):** 18.7

Other Nearby Industrial / Institutional Facilities: Television components, apparel, and metal manufacturing; hospitals, schools and other municipal buildings

6. Profiled Mines (continued)

Utah Mines

Aberdeen
Dugout Canyon
West Ridge

Mine Status: Active
Drainage System: Yes
Use Project: None

2006 Rank: 17
Updated: 05/09/2008

Aberdeen

GEOGRAPHIC DATA

Basin: Uinta

State: UT

Coalbed: L. Sunnyside / Gilson / Aber.

County: Carbon

CORPORATE INFORMATION

Current Operator: Utah American Energy Inc

Owner/Parent Company: Murray Energy Corp

Parent Company Web Site: NA

Previous Owner(s): Andalex Resources Inc

Previous or Alternate Name of Mine: Tower Division

MINE ADDRESS

Contact Name: Karl Yoder, GM

Phone Number: (435) 637-5385

Mailing Address: PO Box 906

City: Price **State:** UT **ZIP:** 84501

GENERAL INFORMATION

Number of Employees at Mine: 142

Mining Method: Longwall

Year of Initial Production: 1980

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: NA

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 11,991

Depth to Seam (ft): NA

Seam Thickness (ft): 6.0 - 8.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	0.0	0.4	2.0	1.5	2.1
Estimated Total Methane Liberated (million cf/day):	0.8	1.2	5.9	5.5	6.9
Emission from Ventilation Systems:	0.8	1.2	5.9	4.1	5.2
Estimated Methane Drained:	-	-	-	1.4	1.7
Estimated Specific Emissions (cf/ton):	8528	998	1075	1304	1202
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 25%

Estimated Current Market Penetration: 0%

Drainage System Used: Vertical Gob Boreholes with Pumps

Aberdeen (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.223	0.44	0.670
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	4.4%	8.7%	13.1%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.0%	2.0%	3.0%

Power Generation Potential

Utility Electric Supplier: PacifiCorp

Transmission Line in County: Yes

Parent Corporation of Utility: Berkshire Hathaway Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	16.6	62.7
Mine Electricity Demand:	13.0	50.1
Prep Plant Electricity Demand:	3.6	12.5
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	5.2	45.7
Assuming 40% Recovery Efficiency:	10.4	91.3
Assuming 60% Recovery Efficiency:	15.6	137.0

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.5
Assuming 40% Recovery (Bcf):	1.0
Assuming 60% Recovery (Bcf):	1.5

Description of Surrounding Terrain: Tablelands; Open High/Low Mountains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Questar Corp

Distance to Pipeline (miles): 4.3

Pipeline Diameter (inches): 20.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA

Pipeline Diameter (inches): NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Carbon

Distance to Plant (miles): 7

Other Nearby Industrial / Institutional Facilities: General manufacturing including mining equipment, concrete, newspaper publishing, printing; Chemical: soap and detergent, industrial gases, inorganic chemicals

Mine Status: Active
Drainage System: Yes
Use Project: None

2006 Rank: 38
Updated: 05/09/2008

Dugout Canyon

GEOGRAPHIC DATA

Basin: Uinta

State: UT

Coalbed: Gilson / Rock Canyon

County: Carbon

CORPORATE INFORMATION

Current Operator: Canyon Fuel Company LLC

Owner/Parent Company: Arch Coal Inc

Parent Company Web Site: www.archcoal.com

Previous Owner(s): Soldier Creek Coal Company

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Erwin Sass, General Mgr.

Phone Number: (435) 636-2872

Mailing Address: PO Box 1029

City: Wellington

State: UT

ZIP: 84542

GENERAL INFORMATION

Number of Employees at Mine: 238

Mining Method: Longwall

Year of Initial Production: 1998

Primary Coal Use: Steam

Life Expectancy: 2115

Sulfur Content of Coal Produced: 0.4% - 0.75%

Prep Plant Located on Site: No

BTUs/lb of Coal Produced: 11,700

Depth to Seam (ft): 2000

Seam Thickness (ft): 7.5 - 8.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	2.1	2.9	3.8	4.6	4.4
Estimated Total Methane Liberated (million cf/day):	1.1	2.1	2.6	2.6	1.7
Emission from Ventilation Systems:	1.1	2.2	1.9	1.9	1.3
Estimated Methane Drained:	-	-	0.6	0.6	0.4
Estimated Specific Emissions (cf/ton):	194	267	247	206	141
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 25%

Estimated Current Market Penetration: 0%

Drainage System Used: Vertical Gob Boreholes with Pumps

Dugout Canyon (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2006 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.055	0.11	0.165
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.5%	1.1%	1.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.2%	0.4%

Power Generation Potential

Utility Electric Supplier: PacifiCorp

Transmission Line in County: Yes

Parent Corporation of Utility: Berkshire Hathaway Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	34.8	131.6
Mine Electricity Demand:	27.3	105.3
Prep Plant Electricity Demand:	7.5	26.3
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	1.3	11.3
Assuming 40% Recovery Efficiency:	2.6	22.5
Assuming 60% Recovery Efficiency:	3.9	33.8

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.4

Description of Surrounding Terrain: NA

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Questar Corp

Distance to Pipeline (miles): 3.6

Pipeline Diameter (inches): 20.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA

Pipeline Diameter (inches): NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Carbon

Distance to Plant (miles): 13.5

Other Nearby Industrial / Institutional Facilities: General manufacturing including lumber processing, mining equipment, newspaper publishing, conveyor belt manufacturing; Steel fabrication

Mine Status:	Active		
Drainage System:	No	**2006 Rank:**	24
Use Project:	None	**Updated:**	05/09/2008

West Ridge Mine

GEOGRAPHIC DATA

Basin: Uinta

State: UT

Coalbed: Lower Sunnyside

County: Carbon

CORPORATE INFORMATION

Current Operator: Utah American Energy Inc

Owner/Parent Company: Murray Energy Corp

Parent Company Web Site: NA

Previous Owner(s): Andalex Resources Inc

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Gary Gray

Phone Number: (435) 564-4015

Mailing Address: PO Box 1077

City: Price **State:** UT **ZIP:** 84501

GENERAL INFORMATION

Number of Employees at Mine: 227

Mining Method: Longwall

Year of Initial Production: 2001

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: 1.09%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 12,648

Depth to Seam (ft): 2000 - 2500

Seam Thickness (ft): 4.3 - 9.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	2.8	3.0	2.3	2.6	3.0
Estimated Total Methane Liberated (million cf/day):	2.5	3.6	3.5	2.5	3.6
Emission from Ventilation Systems:	2.5	3.6	3.5	2.5	3.6
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	316	443	570	350	430
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

West Ridge Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.116	0.23	0.347
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.5%	3.0%	4.4%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.7%	1.0%

Power Generation Potential

Utility Electric Supplier: PacifiCorp

Transmission Line in County: Yes

Parent Corporation of Utility: Berkshire Hathaway Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	24.0	90.7
Mine Electricity Demand:	18.8	72.5
Prep Plant Electricity Demand:	5.2	18.1
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	2.7	23.6
Assuming 40% Recovery Efficiency:	5.4	47.3
Assuming 60% Recovery Efficiency:	8.1	70.9

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.3
Assuming 40% Recovery (Bcf):	0.5
Assuming 60% Recovery (Bcf):	0.8

Description of Surrounding Terrain: NA

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Questar Corp

Distance to Pipeline (miles): 11.0

Pipeline Diameter (inches): 20.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA

Pipeline Diameter (inches): NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Carbon

Distance to Plant (miles): 20

Other Nearby Industrial / Institutional Facilities: Steel fabrication, misc. general manufacturing including mining equipment and lumber processing

6. Profiled Mines (continued)

Virginia Mines

Buchanan
Deep Mine #26
Miles Branch
No. 2
VP 8

Mine Status: Active
Drainage System: Yes
Use Project: Pipeline

2006 Rank: 6
Updated: 05/09/2008

Buchanan Mine

GEOGRAPHIC DATA

Basin: Central Appalachian
State: VA
Coalbed: Pocahontas No. 3
County: Buchanan

CORPORATE INFORMATION

Current Operator: Consolidation Coal Company

Owner/Parent Company: CONSOL Energy Inc
Parent Company Web Site: www.consolenergy.com
Previous Owner(s): None in last 10 years
Previous or Alternate Name of Mine: Buchanan No. 1

MINE ADDRESS

Contact Name: Thomas F. Hoffman, VP
Phone Number: (276) 498-6900
Mailing Address: Rte 680
City: Keen Mountain
State: VA
ZIP: 24624

GENERAL INFORMATION

Number of Employees at Mine: 414
Mining Method: Longwall
Year of Initial Production: 1983
Primary Coal Use: Steam, Metallurgical
Life Expectancy: NA
Sulfur Content of Coal Produced: 0.73%
Prep Plant Located on Site: Yes
BTUs/lb of Coal Produced: 13,831
Depth to Seam (ft): 1400 - 2000
Seam Thickness (ft): 5.4

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	4.1	4.7	4.4	1.7	5.0
Estimated Total Methane Liberated (million cf/day):	48.2	42.6	43.3	37.1	72.3
Emission from Ventilation Systems:	9.5	7.3	7.5	6.4	8.4
Estimated Methane Drained:	38.7	35.3	35.8	30.6	63.9
Estimated Specific Emissions (cf/ton):	4330	3318	3609	7850	5270
Methane Used (million cf/day):	38.7	34.0	35.7	30.6	51.3

Estimated Current Drainage Efficiency: 88%

Estimated Current Market Penetration: 80%

Drainage System Used: Vertical Gob Boreholes; Horizontal Pre-Mine Boreholes; Vertical Pre-Mine Boreholes

Buchanan Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2006 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	2.346	4.69	7.038
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	16.4%	32.8%	49.3%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	3.8%	7.6%	11.4%

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: American Electric Power Co Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	39.7	150.3
Mine Electricity Demand:	31.2	120.2
Prep Plant Electricity Demand:	8.5	30.1
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	54.8	479.9
Assuming 40% Recovery Efficiency:	109.6	959.9
Assuming 60% Recovery Efficiency:	164.4	1439.8

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	5.3
Assuming 40% Recovery (Bcf):	10.6
Assuming 60% Recovery (Bcf):	15.8

Description of Surrounding Terrain: Open Low Mountains/Low Mountains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Dominion

Distance to Pipeline (miles): 4.2 **Pipeline Diameter (inches):** 8.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Clinch River **Distance to Plant (miles):** 20

Other Nearby Industrial / Institutional Facilities: General manufacturing including mining equipment, concrete, asphalt, and heavy equipment

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 23
Updated: 05/09/2008

Deep Mine #26

GEOGRAPHIC DATA

Basin: Central Appalachian

State: VA

Coalbed: Lower Banner

County: Wise

CORPORATE INFORMATION

Current Operator: Paramount Coal Company Virginia LLC

Owner/Parent Company: Alpha Natural Resources LLC

Parent Company Web Site: www.alphanr.com

Previous Owner(s): None

Previous or Alternate Name of Mine: Virginia Commonwealth 5

MINE ADDRESS

Contact Name: NA

Phone Number: (276) 679-7020

Mailing Address: 1014 Laurel Ave

City: Coeburn **State:** VA **ZIP:** 24230

GENERAL INFORMATION

Number of Employees at Mine: 258

Mining Method: Continuous

Year of Initial Production: 2002

Primary Coal Use: Steam, Metallurgical

Life Expectancy: NA

Sulfur Content of Coal Produced: 0.75% - 0.87%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 13,620

Depth to Seam (ft): NA

Seam Thickness (ft): 4-7

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	0.3	1.1	1.5	1.7	2.0
Estimated Total Methane Liberated (million cf/day):	0.5	1.9	3.0	3.3	3.7
Emission from Ventilation Systems:	0.5	1.9	3.0	3.3	3.7
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	623	620	720	704	672
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Deep Mine #26 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2006 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.119	0.23	0.356
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	2.1%	4.3%	6.4%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.5%	1.0%	1.5%

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: American Electric Power Co Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	15.8	59.7
Mine Electricity Demand:	12.4	47.8
Prep Plant Electricity Demand:	3.4	11.9
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	2.8	24.3
Assuming 40% Recovery Efficiency:	5.5	48.6
Assuming 60% Recovery Efficiency:	8.3	72.9

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.3
Assuming 40% Recovery (Bcf):	0.5
Assuming 60% Recovery (Bcf):	0.8

Description of Surrounding Terrain: NA

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Spectra Energy Corp

Distance to Pipeline (miles): 7.9 **Pipeline Diameter (inches):** 12.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Clinch River **Distance to Plant (miles):** 20

Other Nearby Industrial / Institutional Facilities: Industrial organic chemical plant

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 40
Updated: 05/09/2008

Miles Branch Mine

GEOGRAPHIC DATA

Basin: Central Appalachian

State: VA

Coalbed: Pocahontas 5

County: Tazewell

CORPORATE INFORMATION

Current Operator: Consolidation Coal Company

Owner/Parent Company: CONSOL Energy Inc

Parent Company Web Site: www.consolenergy.com

Previous Owner(s): BC Mining Inc

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Thomas F. Hoffman, VP

Phone Number: (412) 831-4193

Mailing Address: 700 Dry Fork Rd

City: Bandy

State: VA

ZIP: 24602

GENERAL INFORMATION

Number of Employees at Mine: 63

Mining Method: Continuous

Year of Initial Production: 2004

Primary Coal Use: Metallurgical

Life Expectancy: NA

Sulfur Content of Coal Produced: 0.51%

Prep Plant Located on Site: No

BTUs/lb of Coal Produced: 12,977

Depth to Seam (ft): NA

Seam Thickness (ft): 3.6

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	-	-	0.3	0.3	0.3
Estimated Total Methane Liberated (million cf/day):	-	-	0.1	1.0	1.2
Emission from Ventilation Systems:	-	-	0.1	1.0	1.2
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	-	-	119	1397	1393
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Miles Branch Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2006 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.039	0.07	0.116
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	4.6%	9.3%	13.9%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.1%	2.1%	3.2%

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co

Transmission Line in County: Yes

Parent Corporation of Utility: American Electric Power Co Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	2.5	9.4
Mine Electricity Demand:	1.9	7.5
Prep Plant Electricity Demand:	0.5	1.9
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	0.9	7.9
Assuming 40% Recovery Efficiency:	1.8	15.8
Assuming 60% Recovery Efficiency:	2.7	23.7

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.3

Description of Surrounding Terrain: NA

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: NiSource

Distance to Pipeline (miles): 1.5

Pipeline Diameter (inches): 8.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): Na

Pipeline Diameter (inches): NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Clinch River

Distance to Plant (miles): 37

Other Nearby Industrial / Institutional Facilities: General manufacturing including mining equipment, cranes and heavy machinery, newspaper publishing, concrete, electronics; Steel fabrication; Chemical; pharmaceutical preparation, sanitary cleaning products

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 50
Updated: 05/09/2008

No. 2

GEOGRAPHIC DATA

Basin: Central Appalachian
State: VA
Coalbed: Pocahontas No. 3
County: Dickenson

CORPORATE INFORMATION

Current Operator: Black Dog Coal Corporation

Owner/Parent Company: Alpha Natural Resources LLC
Parent Company Web Site: http://www.alphanr.com
Previous Owner(s): None
Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Randy Phillips
Phone Number: (276) 623-2901
Mailing Address: 5703 Crutchfield Drive
City: Norton
State: VA
ZIP: 24273

GENERAL INFORMATION

Number of Employees at Mine: 52
Mining Method: Continuous
Year of Initial Production: 2005
Primary Coal Use: Steam, Metallurgical
Life Expectancy: NA
Sulfur Content of Coal Produced: <1.0%
Prep Plant Located on Site: No
BTUs/lb of Coal Produced: 14,103
Depth to Seam (ft): NA
Seam Thickness (ft): 4.3

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	0.0	0.1	0.1	0.1	0.2
Estimated Total Methane Liberated (million cf/day):	0.2	0.5	0.7	0.6	0.8
Emission from Ventilation Systems:	0.2	0.5	0.7	0.6	0.8
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	2081	1588	2042	1890	1498
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA
Estimated Current Market Penetration: NA
Drainage System Used: None

No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2006 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.027	0.05	0.080
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	4.6%	9.2%	13.7%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.1%	2.1%	3.2%

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: American Electric Power Co Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	1.6	6.0
Mine Electricity Demand:	1.3	4.8
Prep Plant Electricity Demand:	0.3	1.2
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	0.6	5.5
Assuming 40% Recovery Efficiency:	1.2	10.9
Assuming 60% Recovery Efficiency:	1.9	16.4

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: NA

Transmission Pipeline in County? NA

Owner of Nearest Pipeline: NA

Distance to Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Clinch River **Distance to Plant (miles):** 10

Other Nearby Industrial / Institutional Facilities: NA

Mine Status: Abandoned (Active in 2006)
Drainage System: Yes
Use Project: Pipeline

2006 Rank: 25
Updated: 05/09/2008

VP 8

GEOGRAPHIC DATA

Basin: Central Appalachian

State: VA

Coalbed: Pocahontas No. 3

County: Buchanan

CORPORATE INFORMATION

Current Operator: Island Creek Coal Company

Owner/Parent Company: CONSOL Energy Inc

Parent Company Web Site: www.consolenergy.com

Previous Owner(s): None in last 5 years

Previous or Alternate Name of Mine: VP No. 8, Virginia Pocahontas No.8

MINE ADDRESS

Contact Name: Thomas F. Hoffman, VP

Phone Number: (412) 831-4000

Mailing Address: 1800 Washington Rd

City: Pittsburgh **State:** PA **ZIP:** 15241

GENERAL INFORMATION

Number of Employees at Mine: 13

Mining Method: Longwall

Year of Initial Production: 1984

Primary Coal Use: Steam, Metallurgical

Life Expectancy: NA

Sulfur Content of Coal Produced: 0.75%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 14,013

Depth to Seam (ft): 2050

Seam Thickness (ft): 6.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	2.2	1.9	1.5	1.2	0.3
Estimated Total Methane Liberated (million cf/day):	43.0	46.3	39.5	25.3	19.0
Emission from Ventilation Systems:	8.5	7.9	6.9	4.2	3.2
Estimated Methane Drained:	34.6	38.4	32.7	21.1	15.8
Estimated Specific Emissions (cf/ton):	7225	8992	9411	7401	24295*
Methane Used (million cf/day):	34.6	36.9	32.6	21.1	12.7

Estimated Current Drainage Efficiency: 83%

Estimated Current Market Penetration: 80%

Drainage System Used: Vertical Gob Boreholes; Horizontal Pre-Mine Boreholes; Vertical Pre-Mine Boreholes

* CONSOL Energy's VP 8 mine in Virginia has specific emissions of 24,295 cf/ton based on total methane liberated in 2006. However, the mine was shutdown in spring 2006 but gas recovery continued, leading to elevated methane liberated per ton of coal produced. Based on first quarter coal production – the last full quarter of production - of s. 0.259 million short tons and quarterly methane liberation of 1,734 mmcf, specific emissions are 6,695 cf/ton.

VP 8 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.618	1.23	1.853
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	74.7%	149.5%	224.2%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	17.3%	34.7%	52.0%

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co

Transmission Line in County: Yes

Parent Corporation of Utility: American Electric Power Co Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	2.3	8.6
Mine Electricity Demand:	1.8	6.9
Prep Plant Electricity Demand:	0.5	1.7
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	14.4	126.3
Assuming 40% Recovery Efficiency:	28.8	252.7
Assuming 60% Recovery Efficiency:	43.3	379.0

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	1.4
Assuming 40% Recovery (Bcf):	2.8
Assuming 60% Recovery (Bcf):	4.2

Description of Surrounding Terrain: Open Low Mountains/Low Mountains

Transmission Pipeline in County? No

Owner of Nearest Pipeline: Mine owns pipeline that connects to dist. line

Distance to Pipeline (miles): <0.1 **Pipeline Diameter (inches):** NA

Owner of Next Nearest Pipeline: Consolidated Natural Gas Supply Co. (CNG)

Distance to Next Nearest Pipeline (miles): 1.0 **Pipeline Diameter (inches):** 6.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Clinch River **Distance to Plant (miles):** 19

Other Nearby Industrial / Institutional Facilities: NA

6. Profiled Mines (continued)

West Virginia Mines

American Eagle
Beckley Crystal
Blacksville No. 2
Dakota No. 2
Eagle
Federal No. 2
Justice #1
Loveridge No. 22
McElroy
Pinnacle
Robinson Run No. 95
Shoemaker
Whitetail Kittanning

Mine Status:	Active		
Drainage System:	Yes	**2006 Rank:**	28
Use Project:	None	**Updated:**	05/09/2008

American Eagle Mine

GEOGRAPHIC DATA

Basin: Central Appalachian

State: WV

Coalbed: Eagle / Big Eagle

County: Kanawha

CORPORATE INFORMATION

Current Operator: Speed Mining Inc

Owner/Parent Company: Speed Mining Inc

Parent Company Web Site: NA

Previous Owner(s): Appalachian Eagle Inc

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Scott Pettry

Phone Number: (304) 461-3050

Mailing Address: 325 Harper Park Dr

City: Beckley **State:** WV **ZIP:** 25801

GENERAL INFORMATION

Number of Employees at Mine: 145

Mining Method: Continuous

Year of Initial Production: 1990

Primary Coal Use: Steam, Metallurgical

Life Expectancy: NA

Sulfur Content of Coal Produced: <1.5%

Prep Plant Located on Site: No

BTUs/lb of Coal Produced: 13,500

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	3.3	4.1	4.1	3.5	2.4
Estimated Total Methane Liberated (million cf/day):	2.5	4.9	3.5	3.8	5.0
Emission from Ventilation Systems:	2.5	4.9	3.5	3.8	3.0
Estimated Methane Drained:	-	-	-	-	2.0
Estimated Specific Emissions (cf/ton):	282	435	308	403	753
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 40%

Estimated Current Market Penetration: 0%

Drainage System Used: Vertical Gob Boreholes

American Eagle Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.161	0.32	0.483
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	2.4%	4.8%	7.2%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.6%	1.1%	1.7%

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co

Transmission Line in County: Yes

Parent Corporation of Utility: American Electric Power Co Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	19.1	72.2
Mine Electricity Demand:	15.0	57.7
Prep Plant Electricity Demand:	4.1	14.4
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	3.8	32.9
Assuming 40% Recovery Efficiency:	7.5	65.8
Assuming 60% Recovery Efficiency:	11.3	98.8

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.4
Assuming 40% Recovery (Bcf):	0.7
Assuming 60% Recovery (Bcf):	1.1

Description of Surrounding Terrain: NA

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: NiSource

Distance to Pipeline (miles): Adjacent

Pipeline Diameter (inches): <0.1

Owner of Next Nearest Pipeline: Dominion

Distance to Next Nearest Pipeline (miles): 0.93

Pipeline Diameter (inches): 20.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Kanawha River

Distance to Plant (miles): 4

Other Nearby Industrial / Institutional Facilities: General manufacturing including coal processing, agricultural inorganic chemicals, lumber processing, concrete; Chemical: industrial gases, alkalies and chlorine

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 32
Updated: 05/09/2008

Beckley Crystal

GEOGRAPHIC DATA

Basin: Central Appalachian

State: WV

Coalbed: NA

County: Raleigh

CORPORATE INFORMATION

Current Operator: Baylor Mining Inc

Owner/Parent Company: Baylor Mining Inc

Parent Company Web Site: NA

Previous Owner(s): None

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Robert L. Worley

Phone Number: (304) 253-7900

Mailing Address: 147 Whitestick St

City: Mabscott

State: WV

ZIP: 25871

GENERAL INFORMATION

Number of Employees at Mine: 52

Mining Method: Continuous

Year of Initial Production: 2001

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: <1.5%

Prep Plant Located on Site: No

BTUs/lb of Coal Produced: 12,000

Depth to Seam (ft): NA

Seam Thickness (ft): 7.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	0.6	0.5	0.5	0.4	0.3
Estimated Total Methane Liberated (million cf/day):	1.0	2.3	1.5	1.8	2.0
Emission from Ventilation Systems:	1.0	2.3	1.5	1.8	2.0
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	644	1809	1059	1556	2185
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Beckley Crystal (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.065	0.13	0.196
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	7.8%	15.6%	23.4%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.8%	3.6%	5.5%

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: American Electric Power Co Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	2.7	10.1
Mine Electricity Demand:	2.1	8.1
Prep Plant Electricity Demand:	0.6	2.0
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	1.5	13.4
Assuming 40% Recovery Efficiency:	3.1	26.8
Assuming 60% Recovery Efficiency:	4.6	40.2

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.3
Assuming 60% Recovery (Bcf):	0.4

Description of Surrounding Terrain: NA

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: NiSource

Distance to Pipeline (miles): 3.2 **Pipeline Diameter (inches):** 6.0

Owner of Next Nearest Pipeline: NiSource

Distance to Next Nearest Pipeline (miles): 8.6 **Pipeline Diameter (inches):** 20.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Glen Lyn **Distance to Plant (miles):** 35

Other Nearby Industrial / Institutional Facilities: Mining equipment, steel, foam

Mine Status: Active
Drainage System: Yes
Use Project: Pipeline

2006 Rank: 8
Updated: 05/09/2008

Blacksville No. 2

GEOGRAPHIC DATA

Basin: Northern Appalachian
State: WV
Coalbed: Pittsburgh No. 8
County: Monongalia

CORPORATE INFORMATION

Current Operator: Consolidation Coal Company

Owner/Parent Company: CONSOL Energy Inc
Parent Company Web Site: www.consolenergy.com
Previous Owner(s): None in last 10 years
Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Thomas F. Hoffman, VP
Phone Number: (412) 831-4000
Mailing Address: 1800 Washington Dr
City: Pittsburgh
State: PA
ZIP: 15241

GENERAL INFORMATION

Number of Employees at Mine: 503
Mining Method: Longwall
Year of Initial Production: 1971
Primary Coal Use: Steam
Life Expectancy: NA
Sulfur Content of Coal Produced: 1.97%
Prep Plant Located on Site: Yes
BTUs/lb of Coal Produced: 13,419
Depth to Seam (ft): 800 - 1150
Seam Thickness (ft): 7.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	4.8	5.4	5.7	5.3	5.0
Estimated Total Methane Liberated (million cf/day):	9.0	6.1	7.7	8.1	9.7
Emission from Ventilation Systems:	5.7	4.7	6.4	6.4	7.2
Estimated Methane Drained:	3.3	1.4	1.4	1.6	2.5
Estimated Specific Emissions (cf/ton):	684	408	493	560	701
Methane Used (million cf/day):	3.3	1.4	1.4	1.6	2.5

Estimated Current Drainage Efficiency: 25%

Estimated Current Market Penetration: 100%

Drainage System Used: Vertical Gob Boreholes with Pumps

Blacksville No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.314	0.62	0.942
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	2.2%	4.5%	6.7%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.5%	1.0%	1.6%

Power Generation Potential

Utility Electric Supplier: Monongahela Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: Allegheny Energy Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	39.9	151.2
Mine Electricity Demand:	31.4	120.9
Prep Plant Electricity Demand:	8.6	30.2
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	7.3	64.2
Assuming 40% Recovery Efficiency:	14.7	128.5
Assuming 60% Recovery Efficiency:	22.0	192.7

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.7
Assuming 40% Recovery (Bcf):	1.4
Assuming 60% Recovery (Bcf):	2.1

Description of Surrounding Terrain: Open Low Mountains/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Equitable Resources Inc

Distance to Pipeline (miles): 1.2 **Pipeline Diameter (inches):** 10.0

Owner of Next Nearest Pipeline: Equitable Resources Inc

Distance to Next Nearest Pipeline (miles): 1.7 **Pipeline Diameter (inches):** 3.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Rivesville **Distance to Plant (miles):** 15.5

Other Nearby Industrial / Institutional Facilities: Pharmaceuticals, chemicals, apparel, lumber, and glass manufacturing; hospitals, university, and other municipal buildings

Mine Status:	Active (Abandoned 2007)		
Drainage System:	No	**2006 Rank:**	44
Use Project:	None	**Updated:**	05/09/2008

Dakota No. 2

GEOGRAPHIC DATA

Basin: Central Appalachian

State: WV

Coalbed: Pittsburgh No. 8

County: Boone

CORPORATE INFORMATION

Current Operator: Dakota LLC

Owner/Parent Company: Magnum Coal Company

Parent Company Web Site: www.magnumcoal.com

Previous Owner(s): Dakota Mining Inc

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Amanda Lawson

Phone Number: (304) 255-7458

Mailing Address: 430 Harper Park, Ste A

City: Beckley **State:** WV **ZIP:** 25801

GENERAL INFORMATION

Number of Employees at Mine: 2

Mining Method: Continuous

Year of Initial Production: 1996

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: <1.5%

Prep Plant Located on Site: No

BTUs/lb of Coal Produced: 13,500

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	1.5	1.5	1.4	1.1	0.6
Estimated Total Methane Liberated (million cf/day):	1.0	1.5	0.8	1.9	1.0
Emission from Ventilation Systems:	1.0	1.5	0.8	1.9	1.0
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	234	366	193	651	601
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Dakota No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.032	0.06	0.096
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.9%	3.8%	5.7%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.4%	0.9%	1.3%

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: American Electric Power Co Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	4.8	18.0
Mine Electricity Demand:	3.7	14.4
Prep Plant Electricity Demand:	1.0	3.6
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	0.7	6.6
Assuming 40% Recovery Efficiency:	1.5	13.1
Assuming 60% Recovery Efficiency:	2.2	19.7

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: NA

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Dominion

Distance to Pipeline (miles): 6.0 **Pipeline Diameter (inches):** 10.0

Owner of Next Nearest Pipeline: Dominion

Distance to Next Nearest Pipeline (miles): 7.3 **Pipeline Diameter (inches):** 12.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Kanawha River **Distance to Plant (miles):** 24

Other Nearby Industrial / Institutional Facilities: Coal processing

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 39
Updated: 05/09/2008

Eagle Mine

GEOGRAPHIC DATA

Basin: Central Appalachian

State: WV

Coalbed: Eagle / Big Eagle

County: Kanawha

CORPORATE INFORMATION

Current Operator: Newtown Energy Inc

Owner/Parent Company: Newtown Energy Inc

Parent Company Web Site: NA

Previous Owner(s): None

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: James I Bunn

Phone Number: (304) 837-8587

Mailing Address: PO Box 189

City: Comfort

State: WV

ZIP: 25049

GENERAL INFORMATION

Number of Employees at Mine: 197

Mining Method: Continuous

Year of Initial Production: 2000

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: <1.5%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 13,500

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	1.2	1.5	1.4	1.4	1.3
Estimated Total Methane Liberated (million cf/day):	0.8	1.0	1.2	0.8	1.2
Emission from Ventilation Systems:	0.8	1.0	1.2	0.8	1.2
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	263	241	302	212	350
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Eagle Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2006 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.041	0.08	0.122
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.1%	2.2%	3.3%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.5%	0.8%

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co   **Transmission Line in County:** Yes

Parent Corporation of Utility: American Electric Power Co Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	10.3	39.0
Mine Electricity Demand:	8.1	31.2
Prep Plant Electricity Demand:	2.2	7.8
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	0.9	8.3
Assuming 40% Recovery Efficiency:	1.9	16.6
Assuming 60% Recovery Efficiency:	2.8	24.9

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.3

Description of Surrounding Terrain: NA

Transmission Pipeline in County? NA

Owner of Nearest Pipeline: Dominion

Distance to Pipeline (miles): 0.5   **Pipeline Diameter (inches):** 6.0

Owner of Next Nearest Pipeline: Dominion

Distance to Next Nearest Pipeline (miles): 2.7   **Pipeline Diameter (inches):** 12.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Kanawha River   **Distance to Plant (miles):** 8.5

Other Nearby Industrial / Institutional Facilities: General manufacturing including coal processing, inorganic chemicals, lumber processing; Chemical: industrial gases, alkalies and chlorine

Mine Status: Active
Drainage System: Yes
Use Project: Elec Power

2006 Rank: 12
Updated: 05/09/2008

Federal No. 2

GEOGRAPHIC DATA

Basin: Northern Appalachian
State: WV
Coalbed: Pittsburgh No. 8
County: Monongalia

CORPORATE INFORMATION

Current Operator: Eastern Associated Coal LLC

Owner/Parent Company: Patriot Coal Corporation
Parent Company Web Site: NA
Previous Owner(s): Peabody Energy Corp
Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Dennis Richards, Operations Mgr.
Phone Number: (304) 449-8154
Mailing Address: 1044 Miracle Run Rd
City: Fairview
State: WV
ZIP: 26570

GENERAL INFORMATION

Number of Employees at Mine: 483
Mining Method: Longwall
Year of Initial Production: 1968
Primary Coal Use: Steam
Life Expectancy: 2011
Sulfur Content of Coal Produced: 2.15%
Prep Plant Located on Site: Yes
BTUs/lb of Coal Produced: 13,330
Depth to Seam (ft): 800 - 1250
Seam Thickness (ft): 7.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	5.0	4.4	4.9	4.1	4.6
Estimated Total Methane Liberated (million cf/day):	12.0	8.8	5.7	6.6	6.7
Emission from Ventilation Systems:	10.6	7.6	4.6	5.6	5.7
Estimated Methane Drained:	1.4	1.1	1.1	1.0	1.0
Estimated Specific Emissions (cf/ton):	876	726	428	589	531
Methane Used (million cf/day):	0.4	0.1	0.0	0.2	0.2

Estimated Current Drainage Efficiency: 15%
Estimated Current Market Penetration: 23%
Drainage System Used: Vertical Gob Boreholes

Federal No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2006 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.218	0.43	0.655
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.7%	3.4%	5.1%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.4%	0.8%	1.2%

Power Generation Potential

Utility Electric Supplier: Monongahela Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: Allegheny Energy Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	36.6	138.7
Mine Electricity Demand:	28.8	110.9
Prep Plant Electricity Demand:	7.9	27.7
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	5.1	44.6
Assuming 40% Recovery Efficiency:	10.2	89.3
Assuming 60% Recovery Efficiency:	15.3	133.9

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.5
Assuming 40% Recovery (Bcf):	1.0
Assuming 60% Recovery (Bcf):	1.5

Description of Surrounding Terrain: Open Low Mountains/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Equitable Resources Inc

Distance to Pipeline (miles): 0.7 **Pipeline Diameter (inches):** 3.0

Owner of Next Nearest Pipeline: Equitable Resources Inc

Distance to Next Nearest Pipeline (miles): 2.4 **Pipeline Diameter (inches):** 12.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Rivesville **Distance to Plant (miles):** 12.5

Other Nearby Industrial / Institutional Facilities: Pharmaceuticals, chemicals, apparel, and glass manufacturing; hospitals, university, and other municipal buildings

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 46
Updated: 05/09/2008

Justice #1

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: WV

Coalbed: Powellton / Buffalo Crk

County: Boone

CORPORATE INFORMATION

Current Operator: Independence Coal Company Inc

Owner/Parent Company: Massey Energy Company

Parent Company Web Site: www.masseyenergyco.com

Previous Owner(s): Oasis Contracting Inc

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Brad Ball, Chief Engr.

Phone Number: (304) 369-7103

Mailing Address: HC 78, Box 1800

City: Madison

State: WV

ZIP: 25130

GENERAL INFORMATION

Number of Employees at Mine: 156

Mining Method: Longwall

Year of Initial Production: 1987

Primary Coal Use: Steam, Metallurgical

Life Expectancy: NA

Sulfur Content of Coal Produced: <1.5%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 13,500

Depth to Seam (ft): 800 - 1000

Seam Thickness (ft): 6.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	2.6	1.8	0.9	0.7	0.9
Estimated Total Methane Liberated (million cf/day):	3.3	2.8	2.2	1.0	0.9
Emission from Ventilation Systems:	3.3	2.8	2.2	1.0	0.9
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	461	566	914	515	363
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Justice #1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.030	0.06	0.090
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.2%	2.3%	3.5%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.5%	0.8%

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: American Electric Power Co Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	7.4	28.0
Mine Electricity Demand:	5.8	22.4
Prep Plant Electricity Demand:	1.6	5.6
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	0.7	6.2
Assuming 40% Recovery Efficiency:	1.4	12.3
Assuming 60% Recovery Efficiency:	2.1	18.5

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: NA

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Dominion

Distance to Pipeline (miles): 0.5 **Pipeline Diameter (inches):** 12.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Kanawha River **Distance to Plant (miles):** 23

Other Nearby Industrial / Institutional Facilities: Lumber and coal processing

Mine Status: Active
Drainage System: Yes
Use Project: Pipeline

2006 Rank: 14
Updated: 05/09/2008

Loveridge No. 22

GEOGRAPHIC DATA

Basin: Northern Appalachian
State: WV
Coalbed: Pittsburgh No. 8
County: Marion

CORPORATE INFORMATION

Current Operator: Consolidation Coal Company

Owner/Parent Company: CONSOL Energy Inc
Parent Company Web Site: www.consolenergy.com
Previous Owner(s): None in last 10 years
Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: John Higgins
Phone Number: (304) 285-2223
Mailing Address: PO Box 40
City: Fairview
State: WV
ZIP: 26570

GENERAL INFORMATION

Number of Employees at Mine: 544
Mining Method: Longwall
Year of Initial Production: 1953
Primary Coal Use: Steam
Life Expectancy: NA
Sulfur Content of Coal Produced: 2.69%
Prep Plant Located on Site: Yes
BTUs/lb of Coal Produced: 13,175
Depth to Seam (ft): 800 - 1250
Seam Thickness (ft): 7.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	-	0.3	5.0	6.4	6.4
Estimated Total Methane Liberated (million cf/day):	3.2	5.3	5.3	5.8	7.1
Emission from Ventilation Systems:	2.0	0.9	3.7	4.1	5.3
Estimated Methane Drained:	1.3	4.4	1.6	1.7	1.8
Estimated Specific Emissions (cf/ton):	-	6406	387	334	406
Methane Used (million cf/day):	-	-	-	1.7	1.8

Estimated Current Drainage Efficiency: 25%
Estimated Current Market Penetration: 100%
Drainage System Used: Vertical Gob Boreholes with Pumps

Loveridge No. 22 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.230	0.46	0.691
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.3%	2.6%	4.0%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.6%	0.9%

Power Generation Potential

Utility Electric Supplier: Monongahela Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: Allegheny Energy Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	50.6	191.5
Mine Electricity Demand:	39.7	153.2
Prep Plant Electricity Demand:	10.9	38.3
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	5.4	47.1
Assuming 40% Recovery Efficiency:	10.8	94.2
Assuming 60% Recovery Efficiency:	16.1	141.4

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.5
Assuming 40% Recovery (Bcf):	1.0
Assuming 60% Recovery (Bcf):	1.6

Description of Surrounding Terrain: Open Low Mountains/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Equitable Resources Inc

Distance to Pipeline (miles): 1.4 **Pipeline Diameter (inches):** 12.0

Owner of Next Nearest Pipeline: Equitable Resources Inc

Distance to Next Nearest Pipeline (miles): 1.9 **Pipeline Diameter (inches):** 16.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Rivesville **Distance to Plant (miles):** 9.7

Other Nearby Industrial / Institutional Facilities: Lighting products, temperature control equipment, general machining, apparel, lumber, hospital and other municipal buildings

Mine Status: Active
Drainage System: Yes
Use Project: None

2006 Rank: 1
Updated: 05/09/2008

Mc Elroy Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian
State: WV
Coalbed: Pittsburgh No. 8
County: Marshall

CORPORATE INFORMATION

Current Operator: McElroy Coal Company

Owner/Parent Company: CONSOL Energy Inc
Parent Company Web Site: www.consolenergy.com
Previous Owner(s): None
Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Dave Eraskovich, Supt.
Phone Number: (304) 843-3700

Mailing Address: Rd 1

City: Glen Easton
State: WV
ZIP: 26039

GENERAL INFORMATION

Number of Employees at Mine: 822
Mining Method: Longwall
Year of Initial Production: 1968
Primary Coal Use: Steam
Life Expectancy: NA
Sulfur Content of Coal Produced: 3.98% - 4.42%
Prep Plant Located on Site: Yes
BTUs/lb of Coal Produced: 12,300
Depth to Seam (ft): 600 - 1200
Seam Thickness (ft): 5.0 - 5.4

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	4.8	6.8	8.4	10.4	10.5
Estimated Total Methane Liberated (million cf/day):	7.4	1.6	8.2	13.3	15.1
Emission from Ventilation Systems:	7.4	1.6	8.2	11.3	12.8
Estimated Methane Drained:	-	-	-	2.0	2.3
Estimated Specific Emissions (cf/ton):	565	88	356	467	525
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 15%

Estimated Current Market Penetration: 0%

Drainage System Used: Vertical Gob Boreholes with Pumps

Mc Elroy Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	20%	40%	60%
	Assumed Potential Recovery Efficiency		
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.488	0.97	1.465
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.8%	3.7%	5.5%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.4%	0.9%	1.3%

Power Generation Potential

Utility Electric Supplier: Wheeling Power Co

Transmission Line in County: Yes

Parent Corporation of Utility: American Electric Power Co Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	83.1	314.3
Mine Electricity Demand:	65.2	251.4
Prep Plant Electricity Demand:	17.9	62.9
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	11.4	99.9
Assuming 40% Recovery Efficiency:	22.8	199.8
Assuming 60% Recovery Efficiency:	34.2	299.8

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	1.1
Assuming 40% Recovery (Bcf):	2.2
Assuming 60% Recovery (Bcf):	3.3

Description of Surrounding Terrain: High Hills/Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Spectra Energy Corp

Distance to Pipeline (miles): 1.5 **Pipeline Diameter (inches):** 36.0

Owner of Next Nearest Pipeline: Dominion

Distance to Next Nearest Pipeline (miles): 3.2 **Pipeline Diameter (inches):** 30.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Ohio Power Kammer Plant **Distance to Plant (miles):** 2.0

Other Nearby Industrial / Institutional Facilities: Petroleum calcined coke and carbon black, cabinets, industrial chemicals

Mine Status: Active
Drainage System: Yes
Use Project: Pipeline

2006 Rank: 15
Updated: 05/09/2008

Pinnacle

GEOGRAPHIC DATA

Basin: Central Appalachian

State: WV

Coalbed: Pocahontas No. 3

County: Wyoming

CORPORATE INFORMATION

Current Operator: Pinnacle Mining Company LLC

Owner/Parent Company: Cleveland-Cliffs Inc

Parent Company Web Site: www.cleveland-cliffs.com

Previous Owner(s): U.S. Steel Mining Company

Previous or Alternate Name of Mine: Pinnacle No. 50, Gary No. 50, US Steel No. 50

MINE ADDRESS

Contact Name: Doug Williams, VP & GM

Phone Number: (304) 732-5310

Mailing Address: PO Box 338

City: Pineville **State:** WV **ZIP:** 24824

GENERAL INFORMATION

Number of Employees at Mine: 415

Mining Method: Longwall

Year of Initial Production: 1969

Primary Coal Use: Metallurgical

Life Expectancy: 2023

Sulfur Content of Coal Produced: 0.75%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 14,900

Depth to Seam (ft): 600 - 1300

Seam Thickness (ft): 4.2

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	3.5	2.5	1.8	2.6	2.0
Estimated Total Methane Liberated (million cf/day):	13.6	11.8	11.0	16.2	9.8
Emission from Ventilation Systems:	8.0	9.8	8.0	6.5	5.2
Estimated Methane Drained:	5.6	2.0	3.1	9.7	4.6
Estimated Specific Emissions (cf/ton):	1405	1745	2299	2248	1785
Methane Used (million cf/day):	5.6	2.0	3.1	9.7	4.6

Estimated Current Drainage Efficiency: 47%

Estimated Current Market Penetration: 100%

Drainage System Used: Vertical Gob Boreholes; Horizontal Pre-Mine Boreholes

Pinnacle (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.319	0.63	0.958
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	5.1%	10.3%	15.4%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.2%	2.4%	3.6%

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co

Transmission Line in County: Yes

Parent Corporation of Utility: American Electric Power Co Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	16.0	60.4
Mine Electricity Demand:	12.5	48.3
Prep Plant Electricity Demand:	3.4	12.1
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	7.5	65.3
Assuming 40% Recovery Efficiency:	14.9	130.7
Assuming 60% Recovery Efficiency:	22.4	196.0

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.7
Assuming 40% Recovery (Bcf):	1.4
Assuming 60% Recovery (Bcf):	2.2

Description of Surrounding Terrain: Low Mountains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: NiSource

Distance to Pipeline (miles): 0.3 **Pipeline Diameter (inches):** 20.0

Owner of Next Nearest Pipeline: Equitable Resources Inc

Distance to Next Nearest Pipeline (miles): 5.4 **Pipeline Diameter (inches):** 6.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Glen Lyn **Distance to Plant (miles):** 37

Other Nearby Industrial / Institutional Facilities: Mining equipment manufacturing, quarries, coal processing, municipal buildings

Mine Status:	Active			
Drainage System:	Yes		**2006 Rank:**	21
Use Project:	None		**Updated:**	05/09/2008

Robinson Run No. 95

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: WV

Coalbed: Pittsburgh No. 8

County: Harrison

CORPORATE INFORMATION

Current Operator: Consolidation Coal Company

Owner/Parent Company: CONSOL Energy Inc

Parent Company Web Site: www.consolenergy.com

Previous Owner(s): None in last 10 years

Previous or Alternate Name of Mine: No. 95

MINE ADDRESS

Contact Name: Jimmy Brock

Phone Number: (304) 795-4421

Mailing Address: Rt 2, PO Box 152

City: Mannington **State:** WV **ZIP:** 26582

GENERAL INFORMATION

Number of Employees at Mine: 488

Mining Method: Longwall

Year of Initial Production: 1968

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: 2.95% - 3.14%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 13,100

Depth to Seam (ft): 700

Seam Thickness (ft): 6.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	5.0	5.7	6.2	6.1	5.7
Estimated Total Methane Liberated (million cf/day):	5.6	4.9	6.5	5.8	5.7
Emission from Ventilation Systems:	4.5	4.0	4.6	4.1	4.0
Estimated Methane Drained:	1.1	1.0	2.0	1.7	1.7
Estimated Specific Emissions (cf/ton):	410	314	381	345	361
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 30%

Estimated Current Market Penetration: 0%

Drainage System Used: Vertical Gob Boreholes with Pumps

Robinson Run No. 95 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.184	0.36	0.552
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.2%	2.4%	3.5%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.6%	0.8%

Power Generation Potential

Utility Electric Supplier: Monongahela Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: Allegheny Energy Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	45.5	172.2
Mine Electricity Demand:	35.7	137.8
Prep Plant Electricity Demand:	9.8	34.4
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	4.3	37.7
Assuming 40% Recovery Efficiency:	8.6	75.3
Assuming 60% Recovery Efficiency:	12.9	113.0

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.4
Assuming 40% Recovery (Bcf):	0.8
Assuming 60% Recovery (Bcf):	1.2

Description of Surrounding Terrain: Open Low Mountains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Dominion

Distance to Pipeline (miles): 0.6 **Pipeline Diameter (inches):** 16.0

Owner of Next Nearest Pipeline: Equitable Resources Inc

Distance to Next Nearest Pipeline (miles): 0.9 **Pipeline Diameter (inches):** 4.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Harrison **Distance to Plant (miles):** 2.1

Other Nearby Industrial / Institutional Facilities: Aircraft, glass, steel and aluminum, mining equipment, crushed coal, and casket manufacturing; FBI facility, shopping malls, and municipal buildings

Mine Status: Active
Drainage System: No
Use Project: None

2006 Rank: 27
Updated: 05/09/2008

Shoemaker

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: WV

Coalbed: Pittsburgh No. 8

County: Marshall

CORPORATE INFORMATION

Current Operator: Consolidation Coal Company

Owner/Parent Company: CONSOL Energy Inc

Parent Company Web Site: www.consolenergy.com

Previous Owner(s): None in last 10 years

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Rock Harris

Phone Number: (304) 238-1500

Mailing Address: Rd 1 Box 62 A

City: Dallas

State: WV

ZIP: 26036

GENERAL INFORMATION

Number of Employees at Mine: 247

Mining Method: Longwall

Year of Initial Production: 1983

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: 3.3%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 12,172

Depth to Seam (ft): 650

Seam Thickness (ft): 5.0 - 5.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	3.4	3.8	3.7	3.5	1.0
Estimated Total Methane Liberated (million cf/day):	3.4	2.2	3.9	4.2	3.1
Emission from Ventilation Systems:	2.9	1.8	3.3	3.6	3.1
Estimated Methane Drained:	0.5	0.3	0.6	0.6	-
Estimated Specific Emissions (cf/ton):	370	206	385	437	1159
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: Vertical Gob Boreholes with Pumps

Shoemaker (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2006 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.099	0.19	0.298
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	4.1%	8.2%	12.3%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.0%	1.9%	2.9%

Power Generation Potential

Utility Electric Supplier: Wheeling Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: American Electric Power Co Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	7.7	29.0
Mine Electricity Demand:	6.0	23.2
Prep Plant Electricity Demand:	1.6	5.8
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	2.3	20.3
Assuming 40% Recovery Efficiency:	4.6	40.7
Assuming 60% Recovery Efficiency:	7.0	61.0

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.2
Assuming 40% Recovery (Bcf):	0.4
Assuming 60% Recovery (Bcf):	0.7

Description of Surrounding Terrain: High Hills/Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: NiSource

Distance to Pipeline (miles): 1.4 **Pipeline Diameter (inches):** 16.0

Owner of Next Nearest Pipeline: NiSource

Distance to Next Nearest Pipeline (miles): 2.0 **Pipeline Diameter (inches):** 16.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Burger **Distance to Plant (miles):** 7.5

Other Nearby Industrial / Institutional Facilities: General manufacturing including iron and steel, asphalt, bakeries, machine shops, printing copper, motor and generator; Chemicals: industrial gases and plastics; several steel plants

Mine Status:	Active		
Drainage System:	No	**2006 Rank:**	36
Use Project:	None	**Updated:**	05/09/2008

Whitetail Kittanning Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian

State: WV

Coalbed: Kittanning

County: Preston

CORPORATE INFORMATION

Current Operator: Kingwood Mining Company LLC

Owner/Parent Company: Alpha Natural Resources LLC

Parent Company Web Site: www.alphanr.com

Previous Owner(s): Coastal Coal-West Virginia LLC

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: Richard L. Craig

Phone Number: (304) 568-2460

Mailing Address: Rte 1, Box 249C

City: Newburg **State:** WV **ZIP:** 26410

GENERAL INFORMATION

Number of Employees at Mine: 272

Mining Method: Continuous

Year of Initial Production: 2000

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: 1.5% - 1.7%

Prep Plant Located on Site: Yes

BTUs/lb of Coal Produced: 13,150

Depth to Seam (ft): NA

Seam Thickness (ft): 6.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	2002	2003	2004	2005	2006
Coal Production (million short tons/year):	2.4	2.4	1.8	1.5	1.4
Estimated Total Methane Liberated (million cf/day):	1.7	1.7	1.8	1.5	1.4
Emission from Ventilation Systems:	1.7	1.7	1.8	1.5	1.4
Estimated Methane Drained:	-	-	-	-	-
Estimated Specific Emissions (cf/ton):	256	264	360	372	366
Methane Used (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: NA

Estimated Current Market Penetration: NA

Drainage System Used: None

Whitetail Kittanning Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2006 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.045	0.09	0.134
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.2%	2.4%	3.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.6%	0.8%

Power Generation Potential

Utility Electric Supplier: Monongahela Power Co **Transmission Line in County:** Yes

Parent Corporation of Utility: Allegheny Energy Inc

	MW	GWh/year
Total Electricity Demand (2006 data):	10.9	41.3
Mine Electricity Demand:	8.6	33.0
Prep Plant Electricity Demand:	2.3	8.3
Potential Generating Capacity (2006 data)		
Assuming 20% Recovery Efficiency:	1.0	9.2
Assuming 40% Recovery Efficiency:	2.1	18.3
Assuming 60% Recovery Efficiency:	3.1	27.5

Pipeline Sales Potential

Potential Annual Gas Sales (2006 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.3

Description of Surrounding Terrain: NA

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Dominion

Distance to Pipeline (miles): 4.8 **Pipeline Diameter (inches):** 8.0

Owner of Next Nearest Pipeline: Dominion

Distance to Next Nearest Pipeline (miles): 4.7 **Pipeline Diameter (inches):** 4.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Albright **Distance to Plant (miles):** 13.5

Other Nearby Industrial / Institutional Facilities: Coal processing, fertilizers, adhesives, general machining, mining equipment

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References and Calculations Used in the Mine Profiles

Data Item	Sources	Calculations
Geographic Data (State, County, Basin, Coalbed)	Keystone (2007)	
Corporate Information:		
Current Owner	Past versions of Keystone Coal Manual and recent coal industry publications	
Previous Owner	Past versions of Keystone Coal Manual and Coal Magazine Annual Longwall Surveys	
Parent Company	Past versions of Keystone Coal Manual and recent coal industry publications	
Phone/Address/Contact Information	Past versions of Keystone Coal Manual and EIA reports.	
General Information:		
Number of Employees	Past versions of Keystone Coal Manual	
Year of Initial Production	MSHA; Past versions of Keystone Coal Manual and articles in coal industry publications	
Life Expectancy:	Past versions of Keystone Coal Manual	
Sulfur Content	Past versions of Keystone Coal Manual	
Mining Method	Past versions of Keystone Coal Manual and Coal Magazine Longwall Survey	
Primary Use	Past versions of Keystone Coal Manual	
Production, Ventilation, and Drainage Data		
Coal Production	MSHA (2007), EIA (2006)	
Emissions from Ventilation Systems	MSHA (1997 - 2007)	
Estimated Methane Drained	The number of mines assumed to have drainage systems is based on calls to individual MSHA districts.	Drainage emissions are estimated by assuming that they are 40% of total liberation, unless otherwise noted.

Data Item	Sources	Calculations
Estimated Total Methane Liberated		Sum of "emissions from ventilation systems" and "estimated methane drained."
Degasification Information		
Drainage system Used	Based on calls to individual MSHA districts offices.	
Estimated Current Drainage Efficiency		Assumed to be 40% unless otherwise noted for mines where the drainage efficiency is known.
Energy and Environmental Value		
CO_2 Equivalent of Methane Emissions Reductions (mm tons)	Global Warming Potential of Methane Compared to CO_2 based on IPCC (2006). GWP is 21 over 100 years.	Estimated 2006 CH_4 liberated (mmcf/yr) x recovery efficiency x 19.2 g/cf x 21 g CO_2/1 g CH_4 x 1 lb / 453.59 g x 1 ton / 2000 lbs
CO_2 Equivalent of Methane Emissions Reductions/CO_2 Emissions from Coal Combustion	CO_2/BTU ratio based on average state values in EIA (1992)	Fraction = [CO_2 equivalent of CH_4 emissions reductions (lbs)] / [2006 coal production (tons) x BTUs/ton x CO_2 emitted lbs/BTU x 99% (fraction oxidized)
BTU Value of Recovered Methane/BTU Value of Coal Produced	BTU/ton value for coal production based on information in Keystone or on average state values from EIA (1992)	Fraction = [2006 CH_4 liberated (cf/yr) x rec. efficiency x 1000 BTUs/cf] / [2006 coal production (tons) x BTUs/ton]
Power Generation Potential		
Electricity Supplier	Directory of Electric Utilities	
Potential Electric Generating Capacity		Capacity = Estimated CH_4 liberated in cf/day x recovery efficiency x 1 day/24 hours x 1000 BTUs/cf x kWh/11000 BTUs
Mine Electricity Demand	Mine electricity needs (24 kWh/ton) are based on ICF Resources (1990a) Ventilation systems are assumed to account for 25% of total electricity demand and to run 24 hours a day (8760 hours/year). Other mine operations are	Demand (MW) = Demand from Ventilation Systems + Demand from Mine Operations + Demand from Prep Plant Demand (MW) ventilation systems = [25% x 24 kWh/ton x tons/year]/

Data Item	Sources	Calculations
	assumed to account for 75% of electricity demand and to run 16 hours a day 220 days per year (3520 hours/year).	[8760 hours/year] Demand (MW) mine operations = [75% x 24 kWh/ton x tons/year]/ [3520 hours/year] Demand (GWh/year) = Demand from Mine + Demand from Prep. Plant Demand from Mine = [24 kWh/ton x tons/year]/ 10^6 Demand from Prep. Plant = [6 kWh/ton x tons/year]/ 10^6
Prep Plant Electricity Demand	Based on Keystone Coal Manual (2007) and *Coal Age* annual Prep Plant surveys. If tons processed per year at the prep plant is available in the Keystone, then that value is used. Otherwise, coal processed is assumed to be equal to mine production. Prep plant electric needs of 6 kWh/ton based on ICF Resources (1990a). Prep plants are assumed to operate 3520 hours/year.	Demand (MW) prep plant = [6 kWh/ton x tons/year]/ 3520 hours/year]
Pipeline Potential		
Potential Annual Gas Sales		Estimated methane liberated (mmcf/d) x 365 days/yr x recovery efficiency
All other information	NGA (2007)	
Other Utilization Potential		
Name of Coal Fired Boiler Located Near Mine (if any)	Platts (2007)	
Distance to Boiler	Platts (2007)	