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EPA

# Technical and Economic Assessment of Coal Mine Methane in Coal-Fired Utility and Industrial Boilers in Northern Appalachia and Alabama

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Coalbed Methane Outreach Program
Atmospheric Pollution Prevention Division
U.S. Environmental Protection Agency

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# COALBED METHANE OUTREACH PROGRAM

The Coalbed Methane Outreach Program (CMOP) is a part of the U.S. Environmental Protection Agency's (U.S. EPA) Atmospheric Pollution Prevention Division. CMOP is a voluntary program that works with coal companies and related industries to identify technologies, markets, and means of financing profitable recovery and use of coal mine methane (a greenhouse gas) that would otherwise be vented to the atmosphere.

CMOP assists the coal mine methane industry by profiling project opportunities at the nation's gassiest mines, conducting mine-specific technical and economic assessments, and identifying private, state, local and federal institutions and programs that could catalyze project development.

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## ACKNOWLEDGMENTS

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# Contents

## 1.0 INTRODUCTION AND BACKGROUND

Coal mine methane (CMM) emissions are those that directly result from coal mining and occur as the following general types:

- Fumigant, the very dilute mixture of CMM in air that flows out of mine ventilation systems.
- High-grade CMM suitable for injection into natural gas pipelines.
- Gob gas, normally a mixture of CMM and air from active and abandoned mines, although gob gas may be almost all methane in certain cases.

Although there are currently few options for using fumigant, one that will benefit power production facilities is its use as combustion air in internal combustion engines and gas turbines. Researhc is ubderway to find other markets for fumigant. The coal mining industry has made good progress in delivering high-grade CMM to natural gas markets. Using gob gas has proven more challenging, although pioneers in the coal, gas, and power industries also have identified several potentially beneficial gob gas uses, as listed below.

- Fuel for coal dryers and other gas-fueled mine equipment.
- Fuel for electrical production.
- Feedstock for gas enrichment systems that upgrade the gas to pipeline quality.
- Supplemental fuel for industrial and utility boilers (delivered in dedicated pipelines).

The last option is the subject of this U.S. Environmental Protection Agency (U.S. EPA) report. Since gob gas (as well as any medium- to high-quality methane) may be cofired with the primary fuel in a variety of existing combustion units including boilers, furnaces, and kilns, it can partially replace common fuels (e.g. coal, oil, and natural gas). The fuel that cofired gob gas replaces is referred to herein as "avoided" fuel. Cofiring gob gas, as explained in the next section, can provide greater value to the buyer than that of the avoided (replaced) primary fuel. This report refers to an "enhanced" gob gas value which is the sum of the avoided fuel plus associated environmental and operational benefits.

The report provides the following:

- A review of the benefits of cofiring.
- A methodology for selecting markets and cofiring projects that have the greatest likelihood for technical and economic feasibility.
- An explanation of the key variables that determine whether or not a project may be viable.

- Two typical cases which appear to exhibit economic viability.

- A summary of several other potential cofiring scenarios for Northern Appalachia and Alabama locations that appear to be feasible and economically attractive.

The purpose of this report is to acquaint potential coal mine operators and energy project developers with the fundamentals of project selection of cofiring gob gas with coal in utility and industrial boilers. These individuals should keep in mind that additional in-depth searches may yield other potential opportunities. For example, a given project may indicate a low return on investment until the developer secures an additional gob gas supply from another nearby mine. Gob gas supplies and available cofiring opportunities will both undergo change as time goes on, so a developer should not be limited to the portfolio of projects suggested in this report.

The reader should also keep in mind that this report presents a screening-level economic analyses based on publicly available data an d standard U.S. EPA assumptions. The analysis described herein investigated the potential viability of CMM cofiring. It foes not account for site-specific factors such as gathering well-field configuration (with respect to compressor stations), geological factors affecting pipeline placement, pipeline right-of-way availability, existing gas sales commitments uncertainty of the economic life of a given boiler, etc. This report, therefore provides an illustrative analysis to determine if future investigation is appropriate for specific settings. As is detailed in Section 5, the analysis does reveal many CMM cofiring opportunities that appear to warrant in-depth evaluation. U.S. EPA will be pleased to conduct a more refined analysis of those potential opportunities if case-specific input data can be made available.

## 2.0 BENEFITS OF COFIRING

Cofiring with gob gas provides a project many benefits that are not available with other potential uses (such as natural gas pipeline injection or electric power generation). Cofiring markets would require less gas processing than do natural gas markets and are normally very flexible (from an engineering viewpoint), allowing for fluctuations in gob gas flow and quality. Benefits from gob gas cofiring accrue to energy buyers as well (e.g. air pollution mitigation and operational improvements). The following sections discuss various benefits of cofiring gob gas.

### 2.1 Minimal Processing

The major contaminants contained in gob gas are nitrogen, carbon dioxide, oxygen, water, and particulate matter. Most boilers can accept all of these constituents with little or no deleterious effects. Therefore, a project developer need not install expensive processing systems to clean the fuel. Instead, the existing boiler system may require only simple processing steps such as removing free moisture and particulates to protect compressors, pipelines, and other components of the transport system.

### 2.2 Flexible Markets

A typical market for cofired gob gas will be a coal-fired boiler which operates most of the available hours in a year. The gas will usually represent a minor portion of a facility's total fuel requirements, so fluctuations in the quality and quantity of gob gas deliveries will have little impact on operational stability. Modern boiler control systems can easily adjust primary fuel feed rates to accommodate gas changes.

### 2.3 Benefits to Purchaser

The buyer of cofired gob gas, perhaps an operator of a utility or industrial coal-fired boiler, may receive many advantages over and above the costs saved by not burning an equivalent amount of primary fuel. The following sections discuss the environmental, operational, and carbon offset benefits. Technical information on these benefits comes from two undated reports published by the Gas Research Institute, U.S. EPA (1997a and 1997b, and Glickert (1997).

#### *2.3.1 Environmental Benefits*

The most important and valuable environmental benefits can be achieved by cofiring gob gas in quantities that are small as compared with total boiler heat (Glickert 1997). The benefits include reductions in NOx, SOx, and particulates (opacity):

- NOx Reduction. When properly configured and optimized, gob gas cofiring may be able to reduce NOx emissions from the entire boiler. Glickert (1997) estimates that a coal plant can achieve a NOx reduction of about 5.0 percent or more for each 1.0 percent of gas heat input using the Fuel Lean Gas Reburning method. For example, using a methane cofiring rate of just 7 percent of total heat input, NOx emissions were reduced by 40 percent in tests run at ComEd's Joliet Generating Station.

  In addition to improving regional air quality, such reductions can offer substantial monetary value to boiler operators. Glickert cites the potential economic benefits that gob gas cofiring could provide for NOx emitters in non-attainment zones after U.S. EPA finalizes its proposal to tighten federal standards for ground-level ozone (smog) in 22 eastern states.[1] Because NOx is a precursor to ozone formation, any method of significantly reducing NOx emissions will be worth many dollars per ton of NOx abated. Some utilities located in ozone non-attainment regions will face NOx offset costs between $500 and $1,500 per ton to comply with the new regulations. Using the low end of that range and data on costs and operating details from a typical cofiring case, Glickert calculated a value for NOx reduction from cofiring of $0.56 per million British thermal units (mmBtu) of CMM used (see Exhibit 1).

The optimum range for Fuel Lean Gas Reburning is between about 2 and 8 percent (methane) gas as a percent of total heat input (Glickert, 1997). Many of the mine/plant pairings in this report are within that range, assuming 40 percent of mine emissions are available for a cofiring project. Gob gas flows that exceed the 8 percent range will begin to create less NOx reduction per unit of input (mmBtu ). Therefore, even though the boiler's emissions continue to decline as it consumes more than 8 percent cofired methane, the effect diminishes on a per-unit basis, resulting in a reduced NOx credit per mmBtu.

**Exhibit 1**

**Sample Estimation of the Value of NOx Reductions Due to Cofiring**

(Assuming that Each 1% of Fuel Input Contributed by methane Reduces NOx by 5%)

(from Glickert, 1997)

*Given:*

- Coal-fired 340 MW boiler.
- Heat rate 10,000 Btu/KWH, or 10 mmBtu per MWH.
- Baseline NOx emissions rate 0.45 lb/mmBtu.

*Tons NOx reduced per hour:*

5% x 340MW x 10mmBtu/MWH x 0.45 lb/mmBtu / 2000lb/ton = 0.03825 tons/hour

*(This increment represents up to 335 tons of NOx during a full year.)*

*Value of reduction:*

$500/ ton x 0.03825 tons/hour = $19.13/hour

*Gas burned per hour:*

1% x 340MW x 10mmBtu/MWH = 34mmBtu/hour

*"NOx value" of cofired gob gas:*

$19.13/hour / 34mmBtu/hour = $0.56/mmBtu

Please note that this example, like all others, contains case-specific parameters. Thus each case will result in a different NOx reduction value per unit of cofired CMM.

[1] U.S. EPA plans to issue final rules by September 1998.

- SOx Reduction. Cofiring methane reduces SOx emissions. These reductions may allow boiler operators to avoid SOx offset purchases, defer other abatement strategies, or even sell the excess SOx credits above their allotment. Currently SOx credits are worth about $100 per ton. Based on that value and case-specific cost estimates, a utility would realize a credit of approximately $0.06 per mm Btu of gas fired.

- Reduced Opacity. Utilities may be able to use gas to reduce stack opacity and thereby avoid plant derating.

### *2.3.2 Operational Benefits*

Utilities use cofired gas in small or large quantities to effect a variety of cost-effective operational improvements (listed below). Not all of these benefits apply to every case. Some benefits will only be available if the utility has access to more substantial CMM quantities (7 to 8 percent or more) or is willing to purchase natural gas in large quantities under certain conditions explained below.

- Improved Ash Quality. If a utility intends to sell its ash to the concrete industry to avoid high disposal costs, gob gas cofiring may enhance this possibility by reducing carbon levels in the ash to saleable limits. Further research is necessary to prove this concept and to determine how much gob gas is required to cause meaningful reductions. There may be another potential benefit from lower carbon in the flyash. Utilities sometimes experience sparking problems in their electrostatic precipitators. Studies show that gas cofiring may mitigate the condition.

- Derate Mitigation. If coal processing equipment inadequacies limit a boiler (either during pulverizer or feeder outages or because the plant has been forced to use low-sulfur coal that contains less heat per pound), gob gas use may mitigate the derating condition by allowing more fuel to enter the boiler.

- Rating Increase. In some cases, a boiler's operating limit may be driven by its forced draft fan rating, even though it may not have reached its total heat release capacity. In this event, the operator may be able to cofire small increments of gob gas without backing off the coal feed – thus ending up with an increased plant rating.

- Lower Turndown. If a boiler can rely primarily on gas during periods of low demand, the minimum operating load can be reduced by almost half of its coal-fired minimum (e.g. from 45 to 25 percent of full load). Having lower turndowns will result in fewer shutdowns and reduced boiler start-up costs. Not only does gas retain its flame stability at low loads, its heat rate is much better than coal in this range. To gain this benefit, however, the boiler operator must have access to larger gas flows than are typically available from a gob gas project.

- Reduction of Slag Buildup. Some utilities have fired gas in coal boilers for short periods or continuously to remove harmful slag deposits. This removal strategy is much less expensive than shutting the boiler down and mechanically removing the deposits. As with the improved turndown ratio described above, however, an operator must have access to an adequate gas supply.

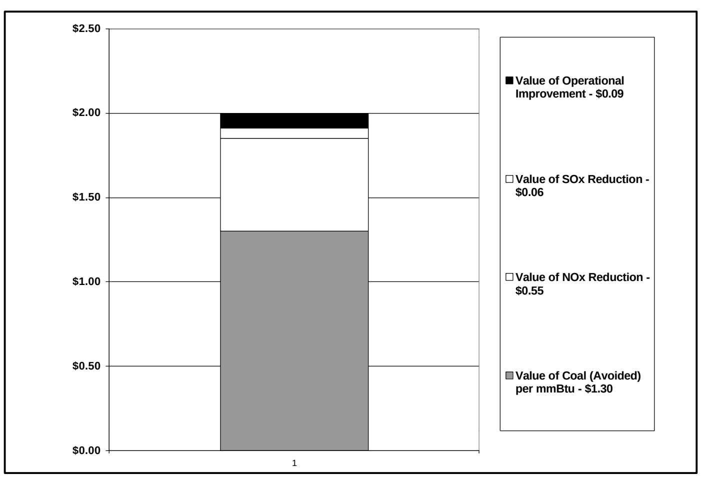
The following two benefits are intangible and probably minor:

- Increased Efficiency (Lower Heat Rate). Methane often burns in large coal boilers with somewhat better combustion characteristics than the coal itself. This results in a small efficiency gain that is partially offset by the need to evaporate the water formed during methane combustion and the fact that the boilers were built to maximize radiant heat transfer from coal and not gas.

- Reduced O&M Costs. There are many ancillary systems operating in a coal-fired boiler that process, handle, and transport coal, as well as remove coal ash. Theoretically, these systems will cost less to operate and maintain when gas is fired as a partial substitute for coal because they are handling less coal. Potential cost reductions from small gas inputs, however, are not proportional to the reduced coal flow and are very hard to identify. For example, in actual practice it is probably impossible to reduce plant payroll because of a 2 to 4 percent reduction in coal throughput.

To accurately quantify the operational benefits discussed above, an analyst must have a detailed knowledge of each boiler, its dispatch profile, it's location with respect to ozone non-attainment zones, its operating history, etc. For the purposes of this report, the analysis of gob gas cofiring options only takes credit for estimated NOx and SOx benefits (in terms of dollars per mmBtu) plus an allowance to cover other possible credits that a typical plant operator would recognize and acknowledge. Exhibit 2 represents an illustrative cofired CMM case with an enhanced valuation of $0.70 per mmBtu for operational improvements and SOx and NOx reductions plus the value of the avoided coal.

**Exhibit 2: Sample Valuation of CMM when Cofired with Coal**




### *2.3.3 Carbon Offsets*

Another type of benefit that has the potential to enhance cofired gob gas' value to future buyers relates to the reduction of greenhouse gas emissions. These emission reductions accrue from beneficially using gob gas instead of venting it to the atmosphere. Because methane has approximately 21 times the global warming effect of carbon dioxide, on the basis of weight (IPCC, 1995), gob gas cofired projects have the potential for significant reduction of greenhouse gas emissions. For example, a project that consumes 6 million cubic feet per day (mmcfd) of CMM would eliminate the equivalent of 0.976 million tons of carbon dioxide per year. When a project developer sells gob gas to a boiler operator, therefore, the sale may carry the option of owning substantial present and future carbon offsets.

One greenhouse gas emissions trade that has broken new ground is between Niagara Mohawk Power Corp., a New York electric utility, and Suncor Energy Inc., a Canadian oil and gas company. The agreement, announced in March of 1998, contains options for 10 million tons of carbon dioxide reductions. It will help Suncor achieve its voluntary greenhouse gas emission reduction targets, while providing Niagara Mohawk with additional funding for new projects that will further reduce global concentrations of greenhouse gases. The company's existing projects include power plant performance improvements, use of less polluting fuels, and development of renewable energy resources (EconSkip@aol.com, 1998).

It is widely expected that greenhouse gas offset trades will increase in frequency and value in the future, either to sell on the open market or to allow the credit holder to emit equivalent amounts of greenhouse gas elsewhere. It is beyond the scope of this report to speculate on the value and timing of such credits.

# 3.0 SELECTION CRITERIA

## 3.1 Regions

The report includes outcomes from a search throughout the Appalachian Region for gassy underground mines that were near large coal-burning boilers. The search identified three concentrations of gassy mines which were close enough to cofiring markets to warrant further study. The selected sections (listed below) include parts of the four states with the highest CMM emissions from underground mines in the country – Alabama, Pennsylvania, Virginia, and West Virginia (U.S. EPA, 1997a).

Cofiring opportunities may exist in other mining regions, but the only one identified to date is the Carbon Mine in Utah with its proximity to the Willow Creek Power Plant. This report, however, focuses only on the Appalachian Region and Alabama.

## 3.2 Project Scenarios

The following are the steps and criteria used to select cofiring project scenarios for further economic analysis.

1. Assembled a list of gassy coal mines with active drainage systems from emissions data (U.S. EPA, 1997a).

2. Addressed areas where mines were adjacent to other mines, and combined emissions from these mines to take advantage of markets with longer delivery distances. Appendices C and E present maps that show the proximity of the mines to the power plants and industrial boilers, respectively.

3. Used GASMAP (Argonne National Laboratory, 1997) to determine the approximate location of the coal mines and large industrial and power plant boilers. GASMAP is a computer database that identifies the locations of facilities involved in natural gas production (including CMM), transportation, and use. GASMAP also provides data on mines and boilers. The database allowed a good first cut in developing coal mine/boiler combinations for analysis.

4. Used topographical maps from the U.S. Geological Survey to plot dedicated pipeline routes from the mine to the boiler location. In general, the routes follow established rights-of-way including existing pipelines, power lines, railroads, and roadways. To the extent possible, selected routes avoid population centers, protected areas, and major river and highway crossings. Once a route was determined, the analyst evaluated the difficulty of the terrain and assigned a terrain factor, which typically added 10 to 20 percent to the overall cost of the pipeline. In cases where the pipeline crosses major rivers, such as the Ohio River, the analysis assumed the use of existing bridges and added an allowance of $500,000 to the overall cost of the pipeline.

5. Applied the following criteria to the list of boilers derived from GASMAP to develop a short list of utility and industrial boilers that would have a realistic possibility of success:

- Each boiler must be close to the gob gas source to minimize pipeline transport cost. This analysis assumed a maximum straight-line distance between each mine and boiler pairing ratio of 5 miles per one mmcfd of CMM.[2]

- The boiler should operate as many hours per year as possible. Only boilers fueled by coal remain on the utility list because they have a greater chance of continuous operation. This is a difficult criterion to apply without data from actual site interviews.

- The boiler should be large enough, at a minimum, to consume the entire gob gas flow without decreasing the combustion efficiency of the unit. Because coal plants are designed to burn coal, not gas, they cannot run entirely on gas. Therefore, each coal boiler has a practical gas cofiring limit which is much less than 100 percent of fuel input.

- A cofiring market should provide the highest possible value for the gob gas. That should present no problem for gas and oil boilers. When gas displaces coal, however, the gas value will be low unless coal displacement is in or near the 8 percent range in order to take full value of NOx rand SOx eduction credits.

### *3.2.1 Mine to Power Plant Combinations*

The analysis used the above criteria to identify candidate power plants located reasonably close to each mine and mine cluster. Utility power plant project scenarios that met all criteria are listed in Table 1, and Section 5.1 presents a preliminary economic analysis for an illustrative case. Appendix C contains maps showing the locations of the possible scenarios. The reader should note that many other project combinations are possible; those shown in this report are strictly illustrative.

### *3.2.2 Mine to Industrial Boiler Combinations*

The task of selecting mine and industrial boiler cofiring scenarios proved to be somewhat more complex because the boilers are normally smaller, they burn a variety of fuels, and some markets are far from gob gas sources. Therefore, the analysis used combinations where boilers were clustered together. A cluster of end-users allows the developer to transport the gob gas more efficiently. In some of the selected cases, a pipeline collects gob gas from several mines and distributes it to multiple end-users. The end-users may be several miles apart, but the overall increased gas flow allows transport across greater pipeline distances. Although the economic analyses of these cases (in Section 5) show positive results, some of them should be viewed as speculative because of the long distances involved, the multiple boiler owners that need coordination, and the possibility that business conditions may reduce market capacity unexpectedly.

[2] It would be possible to save construction cost by using existing natural gas pipelines for transport, but the cost of bringing the gob gas up to pipeline specifications may entail greater expense than the necessary pipeline construction.

**Table 1**
**A Sampling of Mine to Utility Combinations**

| Region | Power Plant | Mine | Estimated Distance (miles) | CMM Available @ 40% Recovery (mmcfd) |
|---|---|---|---|---|
| Alabama | Gaston | Blue Creek 3/Oak Grove | 43.0 | 18.2 |
| | | Blue Creek 4, 5, 7 | 48.0 | 24.8 |
| | Gorgas | Blue Creek 3/Oak Grove | 25.6 | 18.2 |
| | | Blue Creek 4, 5, 7 | 25.6 | 24.8 |
| | | Shoal Creek | 16.8 | 3.3 |
| | James Miller Jr | Blue Creek 3/Oak Grove | 40.0 | 18.2 |
| Mid-Appalachia | Clinch River | Buchanan/VP 8 | 22.3 | 10.4 |
| | Glen Lyn | Buchanan/VP 8 | 71.3 | 10.4 |
| | Kanawha | Pinnacle 50 | 49.6 | 8.6 |
| North-Appalachia | R E Burger | Bailey/Enlow Fork | 37.4 | 9.0 |
| | | McElroy | 11.0 | 1.4 |
| | Cardinal | Bailey/Enlow Fork | 30.0 | 9.0 |
| | | Cumberland/Emerald | 52.0 | 8.2 |
| | Elrama | Bailey/Enlow Fork | 47.2 | 9.0 |
| | Fort Martin | Blacksville 2 | 16.4 | 4.0 |
| | | Cumberland | 21.6 | 4.4 |
| | | Emerald 1 | 21.6 | 3.9 |
| | | Federal 2 | 25.6 | 5.7 |
| | | Cumberland/Emerald 1 | 21.6 | 8.2 |
| | | Cumberland/Emerald plus Bailey/Enlow Fork | 32.6 | 17.2 |
| | Harrison | Federal 2 | 18.0 | 5.7 |
| | | Loveridge 22 | 16.8 | 2.9 |
| | | Robinson Run 95 | 3.2 | 1.8 |
| | | Federal 2/Robinson Run 95 | 17.6 | 7.5 |
| | Hatfield's Ferry | Cumberland | 14.0 | 4.4 |
| | | Emerald 1 | 14.0 | 3.9 |
| | | Federal 2 | 36.0 | 5.7 |
| | | Cumberland/Emerald 1 | 14.0 | 8.2 |
| | | Bailey/Enlow Fork | 25.0 | 9.0 |
| | | Cumberland/Emerald plus Bailey/Enlow Fork | 25.0 | 17.2 |
| | Kammer | Bailey/Enlow Fork | 42.0 | 9.0 |
| | | McElroy | 9.6 | 2.3 |
| | Mitchell | Bailey | 35.2 | 3.3 |
| | | Enlow Fork | 35.2 | 5.7 |
| | | Bailey/Enlow Fork | 35.2 | 9.0 |
| | Rivesville | Blacksville 2 | 17.6 | 4.0 |
| | | Federal 2 | 13.2 | 5.7 |
| | | Loveridge 22 | 8.4 | 2.9 |
| | W H Sammis | Bailey/Enlow Fork | 50.4 | 9.0 |
| | Toronto | Bailey/Enlow Fork | 47.2 | 9.0 |

A summary of selected industrial cofiring project scenarios appears in Table 2. Appendix E also shows maps of these projects. Section 5.2 presents the economic results.

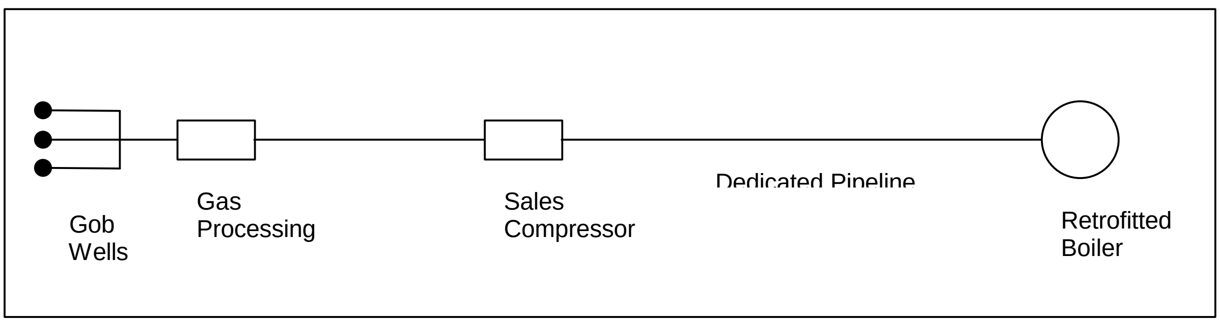
**Table 2**
**A Sampling of Mine to Industrial Boiler Combinations**

| Industrial Boilers | Mine | Estimated Distance (miles) | CMM Available @ 40% Recovery (mmcfd) |
|---|---|---|---|
| **Alabama** | | | |
| Amoco, American Fructose, Monsanto North, Champion | Oak Grove, Shoal Creek, Blue Creek 4, 5, 7 | 112 | 36.7 |
| Hunt Oil, Gulf States, James River | Blue Creek 4, 5, 7 | 89.2 | 24.8 |
| U.S. Alliance | Oak Grove, Shoal Creek | 54.0 | 11.9 |
| | | | |
| **Northern Appalachia** | | | |
| PPG Industries | Blacksville 2, Loveridge, Federal 2 | 48.8 | 12.6 |
| PPG Industries | Enlow Fork, Bailey, Cumberland, Emerald 1 | 32.0 | 17.2 |
| Weirton Steel | Enlow Fork, Bailey, Cumberland, Emerald 1 | 47.2 | 17.2 |

## 4.0 TYPICAL PROJECT CONFIGURATION

A typical project will begin in the gathering lines, just downstream of each wellhead. The mine operator is responsible for establishing and maintaining the wells. The CMM developer connects gathering lines to a central pipeline and uses satellite compressors to transport the gob gas to a processing facility. The gob gas goes through water separation and dehydration units and enters a sales compressor that has sufficient pressurization to bring the gob gas through a dedicated buried pipeline to its destination. At the industrial or utility plant site, the gob gas enters a gas feed system and is injected into a fossil fuel-fired boiler. The project's capitalization includes the boiler retrofit. Exhibit 3 presents a simplified project scenario.

**Exhibit 3**
**Typical Project Configuration**



# 5.0 ECONOMIC ANALYSIS

A preliminary cash flow model computed the internal rate of return (IRR) and net present value (NPV) for each selected cofiring scenario. Each analysis includes a summary table with all of the parameters for each power plant - mine combination, and a separate table showing cash flows over an assumed 10-year project life. The parameters table is linked to the spreadsheet allowing a sensitivity analysis to be performed by changing the input values.

Capital and operating cost estimates, financial assumptions, and other project parameters that went into the model are summarized in Appendix A. It must be emphasized that the cost parameters assumed for this report are only approximations and reasonable assumptions that are appropriate for the screening model. A potential developer must revise each of the estimates using case-specific data.

To compute annual revenue for each project, the model assumes the plant is in a non-attainment region. It uses a first-year sales price of $2.00 (and below) per mmBtu of cofired gas when gob gas replaces coal, or a somewhat higher rate when gob gas replaces oil or natural gas or a mixture of all three fossil fuels. Appendix A includes the price worksheet for coal boilers which takes into account that NOx credits diminish as a function of methane inputs that are above 8 percent of total fuel.

## 5.1 Cofiring in Utility Boilers

### *5.1.1 Illustrative Case #1: Bailey and Enlow Fork Mines to Hatfield's Ferry Power Plant*

The Bailey and Enlow Fork Mines, operated by a subsidiary of CONSOL Coal Group, are located in Greene County, Pennsylvania. In 1996, the mines produced approximately 16.2 million tons of steam coal from the Pittsburgh seam. U.S. EPA estimates that the mines emit about 22.5 mmcfd of CMM, of which about 40 percent is drained. The cofiring case assumes that this 40 percent, or 9.0 mmcfd of CMM would be available for sale to a nearby coal-fired boiler.

The Hatfield's Ferry plant, owned by Appalachian Power Systems (APS), may be a viable market candidate for gob gas from these mines. Hatfield's Ferry is located on the west bank of the Monongahala River, about 25 miles from Bailey and Enlow Fork along an assumed route plotted for this analysis (see map in Appendix C). The analysis assumes that terrain will add 10 percent to the cost of the dedicated pipeline, which is computed at $25 per foot. The Hatfield's Ferry coal-fired units are rated at 576 MW, large enough so retrofitting only one boiler with gas-firing capability would still keep the CMM-to-total-fuel ratio below 8 percent in order to qualify for the assumed enhanced CMM price of $2.00.

Appendix B contains the input table and cash flow analysis for the Bailey/Enlow Fork – Hatfield's Ferry case. It shows a project capital cost of $9.9 million which includes $3.6 million for the dedicated pipeline, $1.7 million for the boiler retrofit, and a 15% contingency factor. The preliminary analysis produced an IRR of 34.8% and an NPV of $13.6 million which should attract developer interest.

Another version of the Bailey/Enlow Fork – Hatfield's Ferry case would include gob gas from the either the Cumberland or the Emerald No.1 Mine, or both. Due to the additional fuel available, and the fact that these mines are located near the pipeline route to

Hatfield's Ferry, the version combining gob gas from all four mines yields a significantly higher IRR (see Table 3).

### *5.1.2 Results of Other Utility Boiler Cofiring Cases*

Table 3 presents the preliminary financial results of other possible utility cases. The results, as expressed by each case's IRR, fall into three general categories:

- 21 economically attractive cases (i.e., after-tax IRR above 25 percent).

- 17 marginally attractive cases (i.e., after-tax IRR above 15 but below 25 percent).

- 2 unattractive cases (i.e., after-tax IRR below 15%).

Each of the 40 utility boiler results shows the effect of mathematical relationships that are largely dependent on three parameters:

- Length of pipeline. A longer pipeline impacts the project by increasing costs associated with pipeline construction, higher sales compressor lease, and line and equipment maintenance.

- Quantity of gob gas flow. A higher flow means more revenue, but it also means that the gathering and transportation costs will rise, albeit at a lower rate.

- Gob gas price. A project that can replace a higher-priced fuel such as natural gas provides greater revenue than one that replaces coal, and the effect on IRR may be dramatic. This impact shows clearly when one compares the two cases involving CMM from Enlow Fork, Bailey, Cumberland, and Emerald 1. The project with the lower fuel price assumption, PPG Industries, has a lower IRR even though it is closer to the mines than the Weirton Steel case where the composite fuel price is about 50 percent higher.

**Table 3**
**Mines to Utility Boilers Financial Results**

| Region | Power Plant | Mine | Estimatd Distance (miles) | IRR (%) | NPV ($000) |
|---|---|---|---|---|---|
| Alabama | Gaston | Blue Creek 3/Oak Grove | 43.0 | 37.2 | 25,745 |
| | | Blue Creek 4, 5, 7 | 48.0 | 43.0 | 37,415 |
| | Gorgas | Blue Creek 3/Oak Grove | 25.6 | 46.3 | 28,361 |
| | | Blue Creek 4, 5, 7 | 25.6 | 50.2 | 36,568 |
| | | Shoal Creek | 16.8 | 23.7 | 3,749 |
| | James Miller Jr | Blue Creek 3/Oak Grove | 40.0 | 38.3 | 28,680 |
| Mid-Appalachia | Clinch River | Buchanan/VP 8 | 22.3 | 39.6 | 16,949 |
| | Glen Lyn | Buchanan/VP 8 | 71.3 | 18.7 | 7,371 |
| | Kanawha | Pinnacle 50 | 49.6 | 22.1 | 8,242 |
| North-Appalachia | R E Burger | Bailey/Enlow Fork | 37.4 | 27.0 | 10,409 |
| | | McElroy | 11.0 | 11.7 | 321 |
| | Cardinal | Bailey/Enlow Fork | 30.0 | 31.7 | 12,842 |
| | | Cumberland/Emerald 1 | 52.0 | 22.0 | 8,538 |
| | Elrama | Bailey/Enlow Fork | 47.2 | 24.6 | 9,614 |
| | Fort Martin | Blacksville 2 | 16.4 | 23.4 | 4,530 |
| | | Cumberland | 21.6 | 22.8 | 4,880 |
| | | Emerald 1 | 21.6 | 19.8 | 3,646 |
| | | Federal 2 | 25.6 | 24.6 | 6,666 |
| | | Cumberland/Emerald 1 | 21.6 | 36.0 | 12,719 |
| | | Cumberland/Emerald plus Bailey/Enlow Fork | 32.6 | 44.3 | 28,108 |
| | Harrison | Federal 2 | 18.0 | 27.6 | 7,342 |
| | | Loveridge 22 | 16.8 | 16.1 | 1,916 |
| | | Robinson Run 95 | 3.2 | 16.9 | 1,367 |
| | | Federal 2/Robinson Run 95 | 17.6 | 34.0 | 11,043 |
| | Hatfield's Ferry | Cumberland | 14.0 | 27.7 | 5,837 |
| | | Emerald 1 | 14.0 | 24.4 | 4,603 |
| | | Federal 2 | 36.0 | 20.2 | 5,356 |
| | | Cumberland/Emerald 1 | 14.0 | 37.7 | 11,588 |
| | | Bailey/Enlow Fork | 25.0 | 34.8 | 13,574 |
| | | Cumberland/Emerald plus Bailey/Enlow Fork | 25.0 | 44.3 | 29,087 |
| | Kammer | Bailey/Enlow Fork | 42.0 | 26.0 | 10,084 |
| | | McElroy | 9.6 | 25.8 | 2,766 |
| | Mitchell | Bailey | 35.2 | 12.8 | 1,146 |
| | | Enlow Fork | 35.2 | 22.8 | 6,175 |
| | | Bailey/Enlow Fork | 35.2 | 29.5 | 11,151 |
| | Rivesville | Blacksville 2 | 17.6 | 23.9 | 3,648 |
| | | Federal 2 | 13.2 | 33.1 | 6,318 |
| | | Loveridge 22 | 8.4 | 31.5 | 3,482 |
| | W H Sammis | Bailey/Enlow Fork | 50.4 | 23.6 | 10,104 |
| | Toronto | Bailey/Enlow Fork | 47.2 | 20.7 | 6,404 |

## 5.2 Cofiring in Industrial Boilers

### *5.2.1 Illustrative Case #2: Enlow Fork, Bailey, Cumberland, and Emerald 1 to PPG Industries*

Enlow Fork and Bailey, operated by a subsidiary of CONSOL Coal Group, and Cumberland and Emerald 1, operated by a subsidiary of Cyprus Amax, are located within approximately 11 miles of each other in Greene County, Pennsylvania. In 1996, the mines produced a total of 24.6 million tons of coal and emitted 43.1 mmcfd of CMM, of which about 14.5 mmcfd was drained. Based on an assumption of 40 percent CMM recovery, this analysis estimated that 17.2 mmcfd will be available for sale to an industrial boiler.

PPG Industries operates a production plant located about 32 miles west of the mines (see map in Appendix E). The analysis assumes a terrain factor of about 19 percent to be added to the cost of the dedicated pipeline which is computed at $25 per foot. PPG Industries' power plant has three coal-fired units totaling 108 MW. To use all the gob gas available from this project the developer would have to retrofit all three boilers. Because the gas-to-total-fuel ratio is well over 8 percent (it is about 66.4 percent, see Appendix D), the environmental benefits are worth somewhat less on a unit basis as discussed in Section 2.3.1. Table A-3 in Appendix A calculates a CMM sales price of $1.53 per mmBtu for a CMM-to-total-fuel ratio in the 61 to 70 percent range.

Appendix D contains the input table and cash flow analysis for the Enlow Fork, Bailey, Cumberland, and Emerald 1 to PPG Industries case. It shows a project capital cost of $12.4 million which includes $5 million for the dedicated pipeline and a 15% contingency factor. Additionally, a 15% contingency factor is applied to the operating cost for all of the industrial boiler cases because they tend to involve more entities and uncertainty, and may require greater management costs. The preliminary economic analysis indicated an IRR of 36.7 % and an NPV of $18.6 million.

### *5.2.2 Results of Other Industrial Boiler Cofiring Cases*

Table 4 presents the preliminary financial results of six industrial cases analyzed by the screening model. Three are located in Alabama and three are in the Pennsylvania – West Virginia region.

**Table 4**
**Mines to Industrial Boilers**
**Financial Analysis**

| Industrial Boilers | | Mines | Estimted Distance (miles) | IRR (%) | NPV ($thousands) |
|---|---|---|---|---|---|
| **Alabama** | | | | | |
| | Amoco, American Fructose, Monsanto North, Champion | Oak Grove, Shoal Creek, Blue Creek 4, 5, 7 | 112 | 47.1 | 66,735 |
| | Hunt Oil, Gulf States, James River | Blue Creek 4, 5, 7 | 89.2 | 39.9 | 34,808 |
| | Kimberly-Clark | Oak Grove, Shoal Creek | 54.0 | 18.4 | 4,852 |
| **Northern Appalachia** | | | | | |
| | PPG Industries | Blacksville 2, Loveridge, Federal 2 | 48.8 | 25.2 | 10,627 |
| | PPG Industries | Enlow Fork/Bailey, Cumberland/Emerald 1 | 32.0 | 36.7 | 18,565 |
| | Weirton Steel | Enlow Fork/Bailey, Cumberland/Emerald 1 | 47.2 | 46.7 | 33,073 |

The results, as expressed by each case's IRR, fall into two general categories:

- 5 economically attractive cases (i.e., after-tax IRR above 25 percent).
- 1 marginally attractive case (i.e., after-tax IRR above 15 but below 25 percent).

As with the utility boiler cases, the industrial cofiring cases are heavily influenced by the same three major factors: length of pipeline, quantity of CMM flow, and sales price.

## 6.0 LIMITS TO THE ANALYSIS

One must view the results of the screening model as very preliminary, partially due to the fact that little direct (site-specific) information was available on which to base the cases. Instead, this analysis applied best-case assumptions to see if the results warranted further analysis. Many cases fall into that category and are candidates for further attention using more refined input data.

Some analytical uncertainties include:

- Scale*.* Many industrial boiler cases, especially in Alabama, tended to exceed the scale of more typical, small-scale, dedicated pipe projects from which the simple cost estimating techniques and rules of thumb used in this analysis derive.

- Complex Pipelines*.* Not only are the pipelines quite long, but there are complexities brought about by clustering of both gob gas producers and industrial users. For example, the only section of line that contains gob gas flowing at full capacity is from the last mine to the first user. The less-used sections at either end may cost more per mmBtu. More estimating work is necessary to reduce this potential analytical uncertainty to an acceptable level.

- CMM Availability*.* All of the potential cases assume available CMM flows of 40 percent of the total 1996 volume of CMM liberated (ventilation emissions plus CMM drainage). This CMM may already be in use. Jim Walter Resources mines, for example, sell about 46 percent of the volume of CMM liberated according to a U.S. EPA report (U.S. EPA, 1997a). This is true to a lesser extent at some of the other mines.

## 7.0 CONCLUSION

This preliminary report shows that a substantial number of economically viable CMM cofiring projects may exist in Appalachia and Alabama. U.S. EPA hopes that mine operators and developers will consider these potentially profitable project options.

**Technical Advantages**

Gob gas is a fuel that is well suited for cofiring with a primary fuel (e.g., coal, oil, and natural gas) in a variety of existing combustion units including boilers, furnaces, and kilns.

Gob gas cofiring offers a project many benefits:

- Only modest processing is required.
- Markets may tolerate fluctuations in flow and quality
- Cofiring yields operational benefits.
- Cofiring yields substantial NOx and SOx reductions.

**Project Economics**

These benefits plus the technical simplicity of a cofiring system result in opportunities for many feasible and potentially profitable projects. The major characteristics of a successful project are:

- Proximity between the mine and boiler.
- Substantial gob gas flows.
- Reasonable value for the CMM.

**Potential Projects**

A preliminary economic screening performed for this report shows that over half of the 46 projects examined would yield internal rates of return of over 25 percent. Many other project possibilities may be feasible.

**Potential for Development**

An alternative energy project developer normally requires assurance that a project can pass three tests. It must be technically feasible, economically viable, and practical to install. Many, but not all, candidate gob gas cofiring projects will meet those tests:

1. Cofiring gob gas is technically uncomplicated and very feasible, and many projects using natural gas, landfill gas, and other fuels have fully demonstrated the concept.

2. Economic analyses in this report demonstrate that cofiring projects can be very profitible if the pipeline distance is proportional to the flow of CMM and the market price is fair. Using conservative cost and revenue projections, most of the projects studied indicated strong after-tax returns on investment.

3. In many cases, the cofiring technique can be quite practical and have a good chance of success. If the developer can secure rights-of-way for the dedicated pipeline, obtain a substantial and steady flow of CMM, and negotiate a realistic price for the fuel, there may be few barriers to implementation. If, however, the pipeline must pass through many land parcels, gas flows are inadequate or not secure, or energy customers are unwilling to pay full value for the fuel, the project will face an uncertain future.

The reader is invited to make use of the report by:

- Using the methodologies presented and applying them to new mine-boiler combinations.

- Modifying the profiled cases with more accurate data and more realistic system configurations.

U.S. EPA welcomes inquiries from potential developers and is available to support further analysis of these projects within its capabilities and charter. For example, to benefit project developers, U.S. EPA offers assistance in using the model developed for this report to analyze actual field data and or in running sensitivity analyses on key parameters.

See Appendix G for more information.

# APPENDIX A

## MODELING ASSUMPTIONS

# APPENDIX A

This appendix provides a brief explanation of the steps involved in analyzing candidate cofiring cases. Tables A-1 through A-4 list specific data, assumptions, and formulae used in the model.

## Model

The analysis employed a very simple Excel spreadsheet model for the utility cofiring cases and modified it slightly for the industrial boiler cases. Each model consists of an input table and an associated discounted cash flow analysis. The tables and cash flow analyses are linked electronically so that changes to any input parameter will recalculate the IRR and NPV. Where several gob gas sources are cofiring candidates for a single energy market, they are grouped onto one table, and each individual cash flow follows sequentially on the same worksheet.

## Data Input

To apply the models, data is input as follows:

- <u>First, enter the assumptions shown in Table A-1.</u> These normally remain constant throughout the development of all cases unless there are special circumstances or the analyst possesses actual field data.

- <u>Next, enter the CMM flow and distance data found in Tables 1 and 3 from the report.</u> Knowing the daily CMM flow determines the appropriate value for the number of satellite compressors, water separation, and dehydration units from Table A-2. Other required data include boiler sizes, terrain factors, and the price of displaced natural gas or oil. When coal is the displaced fuel, use Table A-3 to find the appropriate enhanced fuel value which includes potential and operational credits. In some cases this analysis assumed the retrofit of a second or third boiler to keep the fuel replacement ratio below 8 percent to maximize the NOx credit.

## Sales Compressor Power

The calculations for pressure drop in the dedicated pipeline and the horsepower needed to transport the gob gas are shown in Table A-4. These computations are more complex and were carried out separately from the model. The analysis solved for total horsepower for all stages and divided by 800, the nominal size of the assumed compressor unit. After rounding up to the nearest integer, the number of units was entered into the cases.

## Results

The resulting IRR's and NPV's are presented at the bottom of the cash flow sheets. Observing when the cumulative cash flow changes to a positive indicates Payback, expressed in years.

**Table A-1**
**Modeling Assumptions for Cofired Boiler Model**
(Assumptions Based on U.S. EPA Estimates and Reasonable Allowances)

| Item | Description | Cost |
|---|---|---|
| Gas Quality | Range between 50% and 90% methane. Gas flow calculations use a 75/25 methane/air blend. | N/A |
| **Capital Cost Assumptions** | | |
| Project Development Cost | Fixed cost regardless of project size. Includes all legal, engineering, transaction, and other project development and financing costs. | $350,000. |
| Gathering Lines | High density polyethylene pipelines. Allowance of 30,000 feet of pipe for each satellite compressor. | $5.25/foot |
| Satellite Gas Compression | Compressors purchased. Approximately one satellite compressor per 2.1 mmcfd recovered CMM. | $280,000/unit |
| Gob Gas Upgrade | Water and moisture are removed with water separation and dehydration units. Each unit can treat approximately 4.2 and 3.5 mmcfd (CMM), respectively. | $20,000/unit<br>$25,000/unit |
| Monitoring and Metering | Allowance based on daily CMM flow. | $20,000/mmcfd |
| Pipeline to Sales Compressor | Six inch high density polyethylene (HDPE). Allowance of 30,000 feet per project. | $6.50/foot |
| Sales Compressor Site Construction | Capital costs include site preparation and installation of a power line to the site. | $60,000/unit |
| Dedicated Pipeline | Six inch steel pipe. | $25.00/foot |
| Boiler Conversion | Assumed equal cost per MW for all boiler types. One boiler converted unless more capacity required to remain below 8% replacement limit to maximize NOx reduction credits. | $3,000/MW |
| **Annual Operating Costs** | | |
| Sales Compressors | See separate calculation for sales compressor power requirements. Units are fueled with gob gas. Cost of each leased unit (about 800 hp) includes O & M costs. This rate is not escalated | $10,100/month |
| Project Labor and Operational Costs | Budgeted annual cost based on methane flow. Includes labor, expenses, and overheads at both the mine and boiler plant. | $51,840/mmcfd |
| Satellite Compressor Operating Costs | Budgeted annual costs includes O & M costs. | $18,000/unit |
| Royalties | Assumed as a percentage of gross revenue. | 12.5% |
| Compressor Fuel | Gob gas at no cost to the project. | 0 |
| **Financial Information** | | |
| Capital Source | All equity, no debt. | N/A |
| Project Life | 10 years. | N/A |
| Inflation Rate | Four percent annually. | N/A |
| Depreciation | Straight line method over life of project. | N/A |
| Taxation | Tax allowance is 40 percent of income net of depletion allowance (includes state, local, and U.S. taxes). | N/A |
| NPV | Calculated at 10 percent. | N/A |

**Table A-2**
**Compression and Processing Unit Assumptions**
(Source: U.S. EPA Estimates)

| Total Methane Flow (mmcfd) Greater Than: | Satellite Compressor | Water Separation Unit | Dehydration Unit |
|---|---|---|---|
| 0 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 |
| 2 | 1 | 1 | 1 |
| 3 | 2 | 1 | 1 |
| 4 | 2 | 1 | 2 |
| 5 | 3 | 2 | 2 |
| 6 | 3 | 2 | 2 |
| 7 | 4 | 2 | 2 |
| 8 | 4 | 2 | 3 |
| 9 | 5 | 3 | 3 |
| 10 | 5 | 3 | 3 |
| 11 | 6 | 3 | 4 |
| 12 | 6 | 3 | 4 |
| 13 | 7 | 4 | 4 |
| 14 | 7 | 4 | 4 |
| 15 | 8 | 4 | 5 |
| 16 | 8 | 4 | 5 |
| 17 | 9 | 5 | 5 |
| 18 | 9 | 5 | 6 |
| 19 | 10 | 5 | 6 |
| 20 | 10 | 5 | 6 |
| 21 | 10 | 6 | 6 |
| 22 | 11 | 6 | 7 |
| 23 | 11 | 6 | 7 |
| 24 | 12 | 6 | 7 |
| 25 | 12 | 7 | 8 |
| 26 | 13 | 7 | 8 |
| 27 | 13 | 7 | 8 |
| 28 | 14 | 7 | 8 |
| 29 | 14 | 7 | 9 |
| 30 | 15 | 8 | 9 |
| 31 | 15 | 8 | 9 |
| 32 | 16 | 8 | 10 |
| 33 | 16 | 8 | 10 |
| 34 | 17 | 9 | 10 |
| 35 | 17 | 9 | 10 |
| 36 | 18 | 9 | 11 |

**Table A-3**
**Enhanced CMM Price as a Function of**
**Percent of Boiler Coal Input**
(Source: U.S. EPA Estimates)

| Methane Input Range (% of Total) | Value of Coal Replaced (Avoided) ($/mmBtu) | ΣValue of SOx Reduction and Operational Benefit ($/mmBtu) | Value of NOx Reduction Benefits ($/mmBtu) | Total Value of Cofired Methane ($/mmBtu) |
|---|---|---|---|---|
| 1 – 7.99 | 1.30 | 0.14 | 0.56 | 2.00 |
| 8 – 12.99 | 1.30 | 0.14 | 0.41 | 1.85 |
| 13 – 20.99 | 1.30 | 0.14 | 0.29 | 1.73 |
| 21 – 30.99 | 1.30 | 0.14 | 0.19 | 1.63 |
| 31 – 40.99 | 1.30 | 0.14 | 0.15 | 1.59 |
| 41 – 50.99 | 1.30 | 0.14 | 0.12 | 1.56 |
| 51 – 60.99 | 1.30 | 0.14 | 0.10 | 1.54 |
| 61 – 70 | 1.30 | 0.14 | 0.09 | 1.53 |

**Table A-4**
**Formulae for Pressure and Horsepower**
**Of Sales Compressors**

| | |
|---|---|
| Formula to find Pressure | $P_1 = [P_2^{\,2} + L * ((Q*G^{0.425})/(2826*D^{2.725}))^{1.739}]^{0.5}$ |
| Formula to find Horsepower | $Hp = 0.0838\ K^{-1} * q * T *(C^{K} - 1)$ |

Where:
- $P_1$ = inlet pressure, psia
- $P_2$ = outlet pressure, psia
- Q = gas flow rate in standard cubic feet per hour, scfh
- G = specific gravity
- L = pipeline length, feet
- D = inside diameter, inches
- Hp = horsepower per stage
- q = volume flow rate in mmscf
- T = gas temperature in degrees Rankine (520 stage 1; 553 other stages)
- C = compression ratio (P outlet / P inlet)
- K = (Cp/Cv – 1) / (Cp/Cv); (assumed Cp/Cv for 75 % gob gas = 1.325)

# APPENDIX B

## MINE TO UTILITY BOILER ECONOMIC ANALYSIS

## Illustrative Case #1 - Parameters

# *Hatfield's Ferry Power Plant*

| Parameters | Units | Unit Costs | **Mines** Bailey/Enlow Fork Combined |
|---|---|---|---|
| Methane Recovered | mmcfd | | 9 |
| | mmcfy | | 3,285 |
| Gathering Infrastructure and Gob Gas Cleanup | | | |
| Gathering Pipelines | feet | | 150,000 |
| Water Separation Units | | | 3 |
| Dehydration Unit | | | 3 |
| Satellite Compressor | | | 5 |
| Pipeline to Sales Compressor | feet | | 30,000 |
| Gob Gas Transport | | | |
| Sales Compressor | | | 3 |
| Dedicated Transportation Line | feet | | 132,000 |
| Terrain Factor for Transport Line | | | 1.1 |
| Boilers | | | |
| Coal Replacement | %/Bcf | | 6.5% |
| Boiler Size | MW | | 576 |
| No. of Boilers Converted | | | 1 |
| Royalty Payments | | | 12.5% |
| Inflation Rate | | | 4% |
| Tax Rate | | | 40% |
| Enhanced Gas Value | $/mmBtu | | 2.00 |
| Capital Cost | | | |
| Development Costs | $/project | 350,000 | 350,000 |
| Gathering Pipelines | $/foot | 5.25 | 787,500 |
| Water Separation | $/Unit | 20,000 | 60,000 |
| Dehydration Unit | $/Unit | 25,000 | 75,000 |
| Satellite Compressors | $/Unit | 280,000 | 1,400,000 |
| Monitoring/Metering | $/mmcfd | 20,000 | 180,000 |
| Pipeline to Sales Compressor | $/Unit | 6.50 | 195,000 |
| Sales Compressor | $/Unit | 60,000 | 180,000 |
| Dedicated Transportation Line | $/Unit | 25.00 | 3,630,000 |
| Boiler Conversions | $/MW | 3,000 | 1,728,000 |
| Subtotal | | | 8,585,500 |
| Contingency | | 15% | 1,287,825 |
| Total | | | 9,873,325 |

# Illustrative Case #1 - Cash Flow Analysis

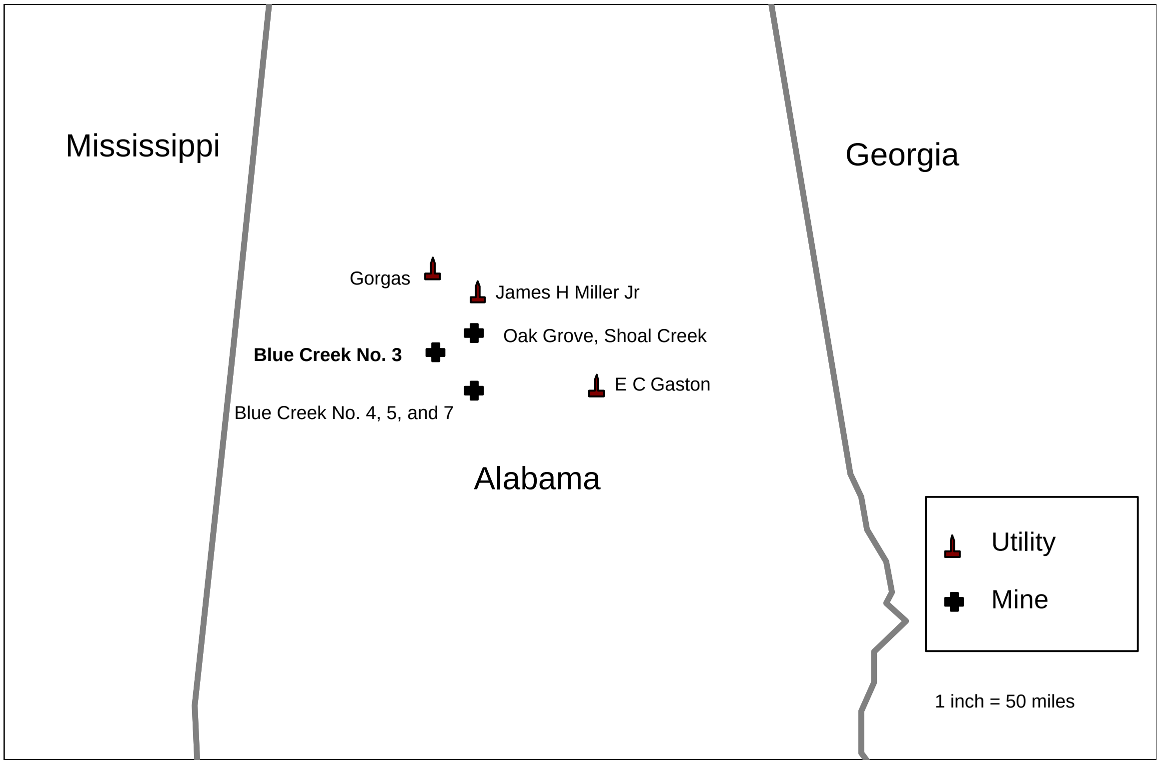
| **Bailey/Enlow Fork to Hatfield's Ferry** | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Revenue** | 000 | | | 5,913 | 6,150 | 6,396 | 6,651 | 6,917 | 7,194 | 7,482 | 7,781 | 8,092 | 8,416 |
| **Operating Costs** | | | | | | | | | | | | | |
| Satellite Compressor O&M | | 18,000 | $/Unit | 90,000 | 93,600 | 97,344 | 101,238 | 105,287 | 109,499 | 113,879 | 118,434 | 123,171 | 128,098 |
| Sales Compressor Lease | and Operation | 121,200 | $/Unit | 363,600 | 363,600 | 363,600 | 363,600 | 363,600 | 363,600 | 363,600 | 363,600 | 363,600 | 363,600 |
| System Operations | | 51,840 | $/mmcfd | 466,560 | 485,222 | 504,631 | 524,817 | 545,809 | 567,642 | 590,347 | 613,961 | 638,520 | 664,060 |
| Total Operating Costs | | | | 920,160 | 942,422 | 965,575 | 989,654 | 1,014,696 | 1,040,740 | 1,067,826 | 1,095,995 | 1,125,291 | 1,155,758 |
| | 000 | | | 920 | 942 | 966 | 990 | 1,015 | 1,041 | 1,068 | 1,096 | 1,125 | 1,156 |

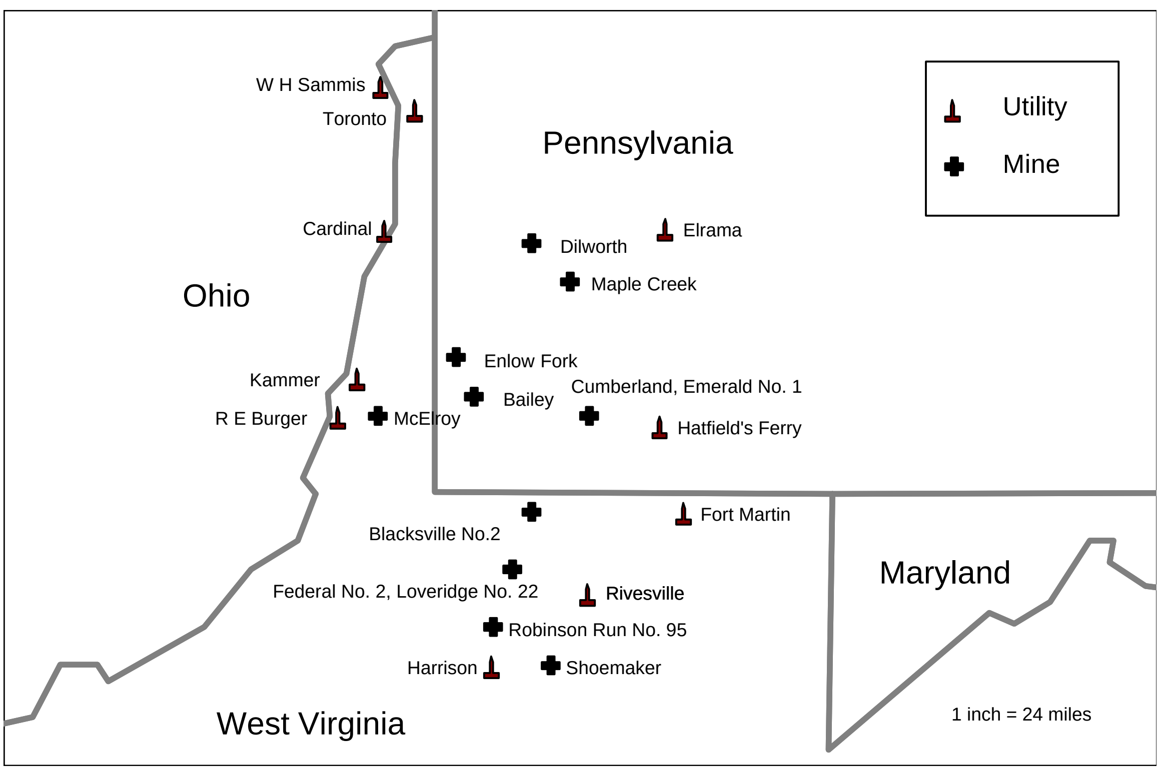
| | | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gross Revenue | | | 5,913 | 6,150 | 6,396 | 6,651 | 6,917 | 7,194 | 7,482 | 7,781 | 8,092 | 8,416 |
| Capital Costs | | (9,873) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Operating Costs | | | (920) | (942) | (966) | (990) | (1,015) | (1,041) | (1,068) | (1,096) | (1,125) | (1,156) |
| Royalty Payments | | | (739) | (769) | (799) | (831) | (865) | (899) | (935) | (973) | (1,012) | (1,052) |
| | | | | | | | | | | | | |
| Gross Income | | | 4,254 | 4,438 | 4,630 | 4,830 | 5,038 | 5,254 | 5,479 | 5,712 | 5,956 | 6,208 |
| Depreciation | Straight Line Method | | (987) | (987) | (987) | (987) | (987) | (987) | (987) | (987) | (987) | (987) |
| Depletion Allowance | | | (887) | (922) | (959) | (998) | (1,038) | (1,079) | (1,122) | (1,167) | (1,214) | (1,262) |
| Net Income | | | 2,379 | 2,529 | 2,684 | 2,845 | 3,013 | 3,188 | 3,369 | 3,558 | 3,754 | 3,959 |
| Taxes | | | (952) | (1,011) | (1,074) | (1,138) | (1,205) | (1,275) | (1,348) | (1,423) | (1,502) | (1,583) |
| | | | | | | | | | | | | |
| Cash Flow | | (9,873) | 3,302 | 3,427 | 3,557 | 3,692 | 3,833 | 3,979 | 4,131 | 4,289 | 4,454 | 4,625 |
| Pay Back | | | (6,571) | (3,144) | 413 | 4,105 | 7,937 | 11,916 | 16,048 | 20,337 | 24,791 | 29,416 |
| | NPV | 13,574 | | | | | | | | | | |
| | IRR | 34.8% | | | | | | | | | | |

# APPENDIX C

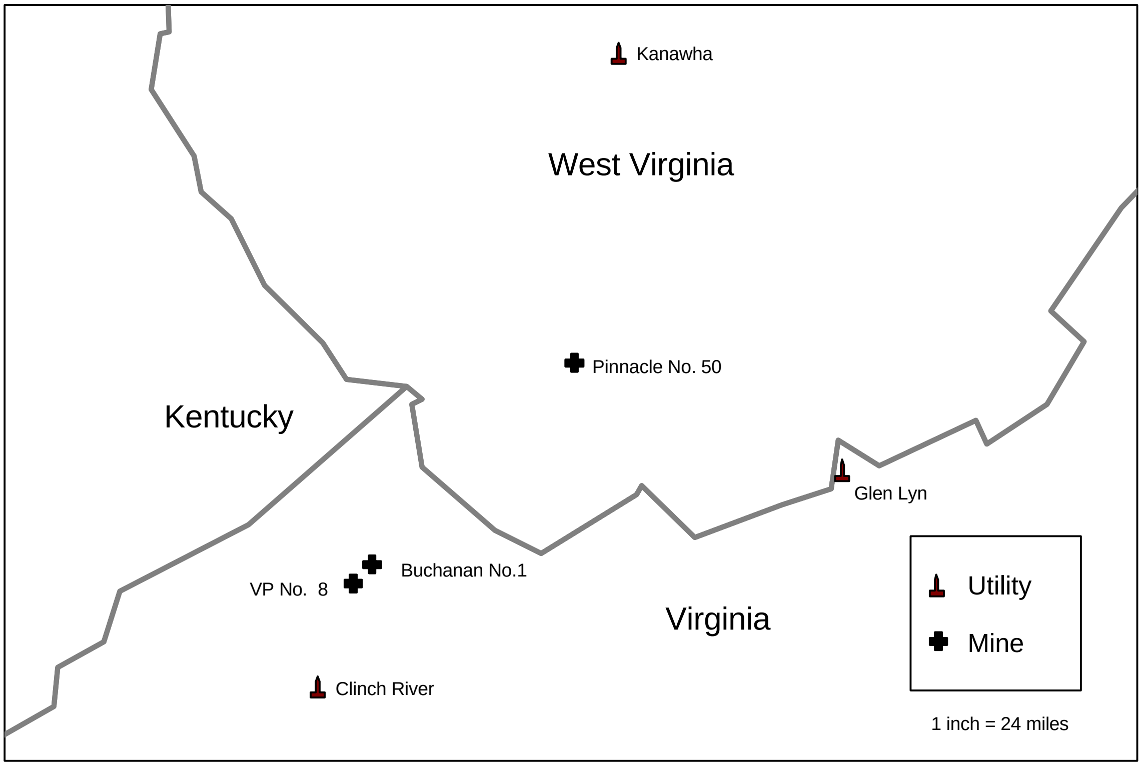
## MINE TO UTILITY BOILER MAPS

## Mine to Utility Boiler Maps



## Mine to Utility Boiler Maps



# APPENDIX D

## MINE TO INDUSTRIAL BOILER ECONOMIC ANALYSIS

## Illustrative Case #2 - Parameters

## *PPG Industries*

| Parameters | Units | Unit Costs | Mines<br>Enlow Fork/Bailey, Cumberland/Emerald |
|---|---|---|---|
| Methane Recovered | mmcfd | | 17.2 |
| | mmcfy | | 6,278 |
| Gathering Infrastructure and Gob Gas Clean Up | | | |
| Gathering Lines | feet | | 270,000 |
| Water Separation Units | each | | 5 |
| Dehydration Units | each | | 5 |
| Satellite Compressors | each | | 9 |
| Pipeline to Sales Compressor | feet | | 30,000 |
| Gob Gas Transport | | | |
| Sales Compressors | each | | 6 |
| Dedicated Pipeline | feet | | 168,960 |
| (diameter) | inches | | 6 |
| Terrain Factor for Transport Line | | | 1.19 |
| Boilers | | | |
| Coal Replacement | % | | 66.4% |
| Total Boiler Size | MW | | 108 |
| Royalty Payments | | | 12.5% |
| Inflation Rate | | | 4% |
| Tax Rate | | | 40% |
| Enhanced CMM Value | $/mmBtu | | 1.53 |
| Capital Cost | | | |
| Development Costs | $/project | 350,000 | 350,000 |
| Gathering Pipelines | $/foot | 5.25 | 1,417,500 |
| Water Separation | $/Unit | 20,000 | 100,000 |
| Dehydration Unit | $/Unit | 25,000 | 125,000 |
| Satellite Compressor | $/Unit | 280,000 | 2,520,000 |
| Monitoring/Metering | $/mmcfd | 20,000 | 344,000 |
| Pipeline to Sales Compressor | $/foot | 6.50 | 195,000 |
| Sales Compressor | $/Unit | 60,000 | 360,000 |
| Dedicated Transportation Line | $/foot | 25.00 | 5,026,560 |
| Boiler Conversions | $/MW | 3,000 | 324,000 |
| Subtotal | | | 10,762,060 |
| Contingency | | 15% | 1,614,309 |
| Total | | | 12,376,369 |

# Illustrative Case #2 - Cash Flow Analysis

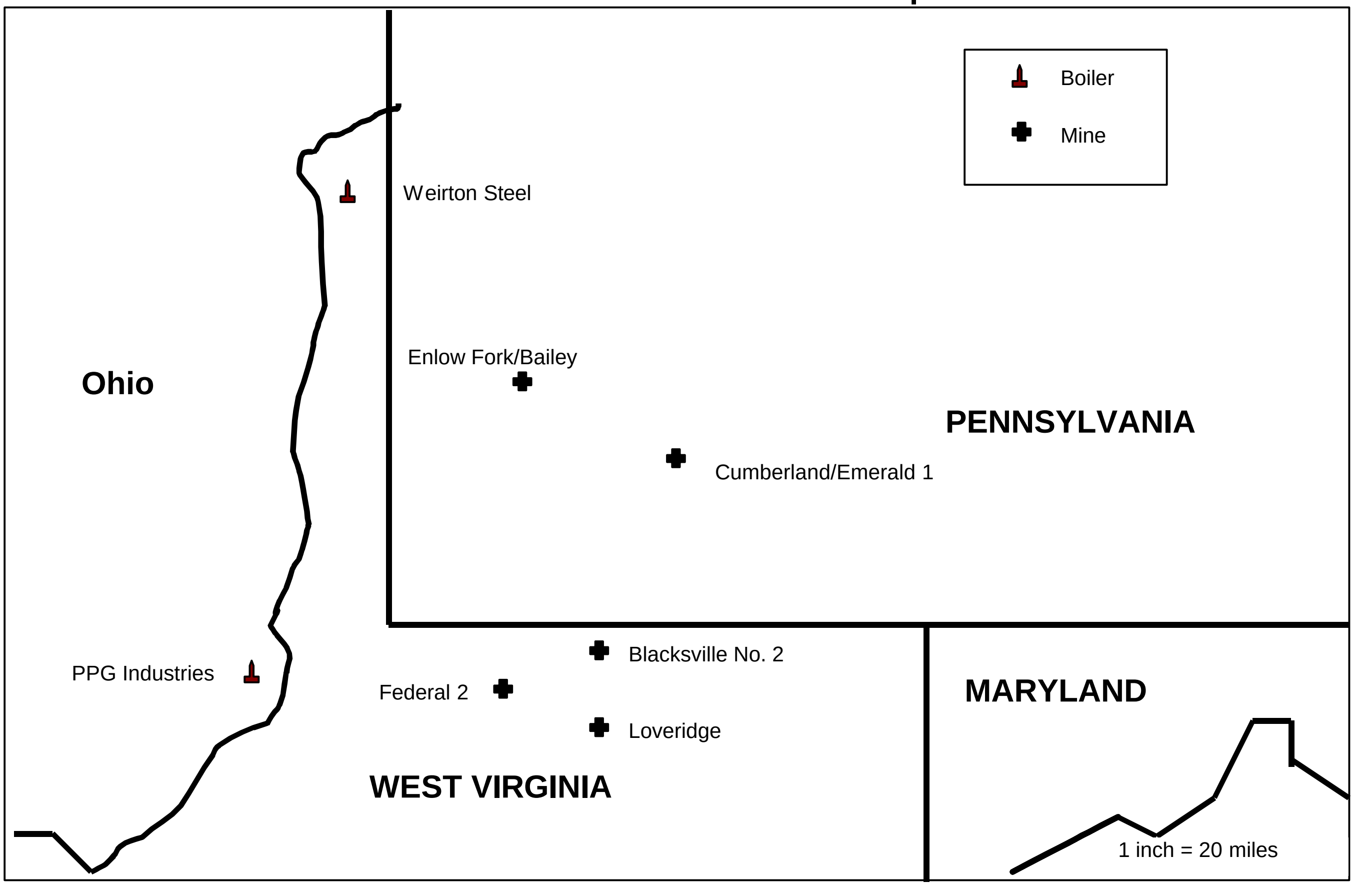
| **Enlow Fork/Bailey, Cumberland/Emerald Mines - PPG Industries** | | | | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Revenue** | 000 | | | 8,991 | 9,350 | 9,724 | 10,113 | 10,518 | 10,938 | 11,376 | 11,831 | 12,304 |
| **Operating Costs** | | | | | | | | | | | | |
| Satellite Compressor O&M | | 18,000 | $/Unit | 168,480 | 175,219 | 182,228 | 189,517 | 197,098 | 204,982 | 213,181 | 221,708 | 230,577 |
| Sales Compressor Lease and Operation | | 121,200 | $/unit | 727,200 | 727,200 | 727,200 | 727,200 | 727,200 | 727,200 | 727,200 | 727,200 | 727,200 |
| System Operations | | 51,840 | $/mmcfd | 927,314 | 964,406 | 1,002,983 | 1,043,102 | 1,084,826 | 1,128,219 | 1,173,348 | 1,220,282 | 1,269,093 |
| Subtotal | | | | 1,822,994 | 1,866,826 | 1,912,411 | 1,959,819 | 2,009,124 | 2,060,401 | 2,113,729 | 2,169,190 | 2,226,870 |
| Contingency | | | 15% | 273,449 | 280,024 | 286,862 | 293,973 | 301,369 | 309,060 | 317,059 | 325,379 | 334,030 |
| Total | | | | 2,096,443 | 2,146,850 | 2,199,272 | 2,253,792 | 2,310,492 | 2,369,461 | 2,430,788 | 2,494,569 | 2,560,900 |
| | 000 | | | 2,096 | 2,147 | 2,199 | 2,254 | 2,310 | 2,369 | 2,431 | 2,495 | 2,561 |

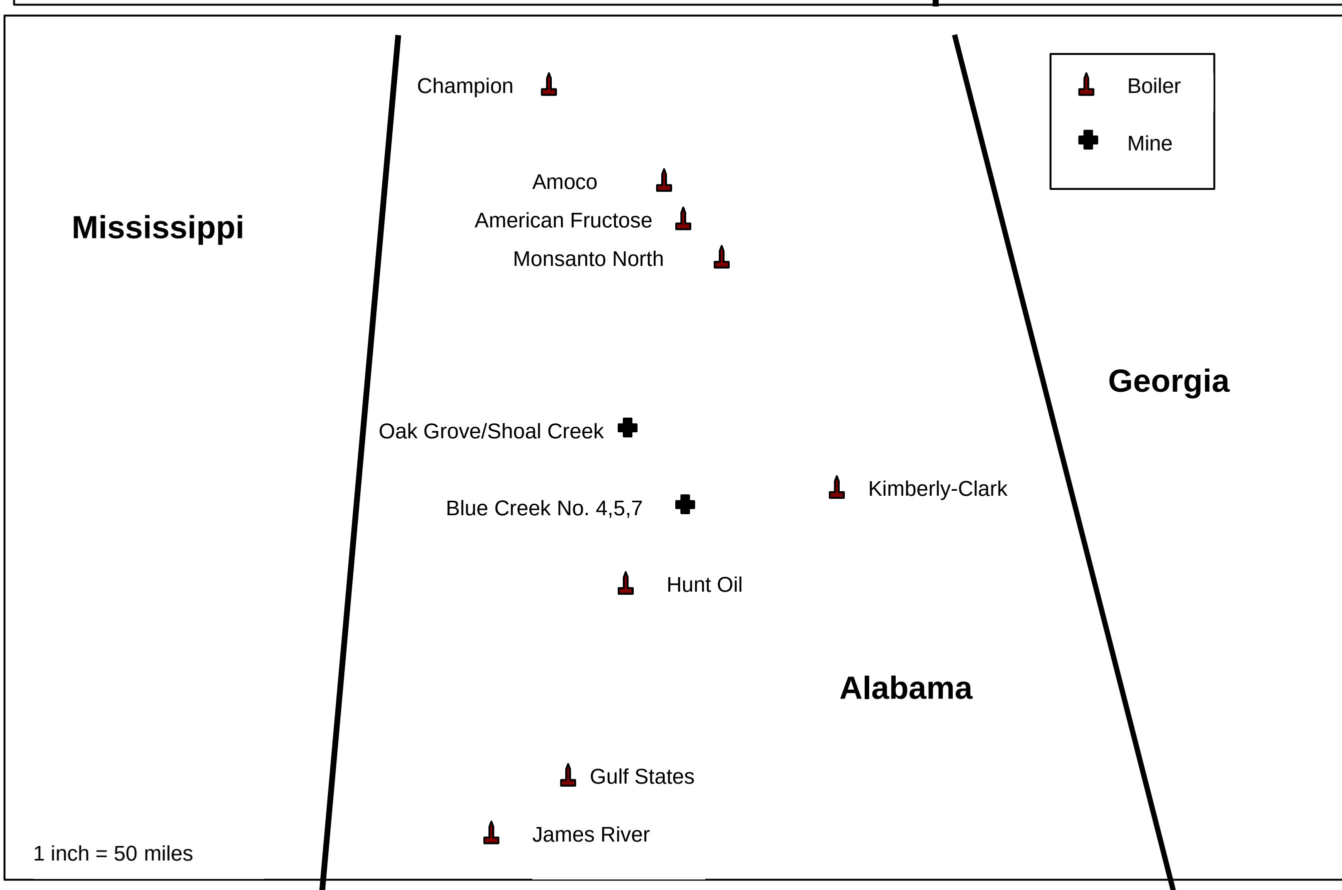
| | | 0 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Gross Revenue | | | 8,991 | 9,350 | 9,724 | 10,113 | 10,518 | 10,938 | 11,376 | 11,831 | 12,304 |
| Capital Costs | | (12,376) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Operating Costs | | | (2,096) | (2,147) | (2,199) | (2,254) | (2,310) | (2,369) | (2,431) | (2,495) | (2,561) |
| Royalty Payments | | | (1,124) | (1,169) | (1,216) | (1,264) | (1,315) | (1,367) | (1,422) | (1,479) | (1,538) |
| | | | | | | | | | | | |
| Gross Income | | | 5,770 | 6,035 | 6,309 | 6,595 | 6,893 | 7,202 | 7,523 | 7,858 | 8,205 |
| Depreciation | Straight Line Method | | (1,238) | (1,238) | (1,238) | (1,238) | (1,238) | (1,238) | (1,238) | (1,238) | (1,238) |
| Depletion Allowance | | | (1,349) | (1,403) | (1,459) | (1,517) | (1,578) | (1,641) | (1,706) | (1,775) | (1,846) |
| Net Income | | | 3,184 | 3,394 | 3,613 | 3,841 | 4,077 | 4,323 | 4,579 | 4,845 | 5,122 |
| Taxes | | | (1,274) | (1,358) | (1,445) | (1,536) | (1,631) | (1,729) | (1,832) | (1,938) | (2,049) |
| | | | | | | | | | | | |
| Cash Flow | | (12,376) | 4,497 | 4,677 | 4,864 | 5,059 | 5,262 | 5,472 | 5,692 | 5,919 | 6,157 |
| Pay Back | | | (3,556) | 1,121 | 5,985 | 11,044 | 16,305 | 21,778 | 27,469 | 33,389 | 39,545 |
| | NPV | 18,565 | | | | | | | | | |
| | IRR | 36.7% | | | | | | | | | |

# APPENDIX E

## Mine to Industrial Boiler Maps

# Mine to Industrial Boiler Maps



# APPENDIX F

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# APPENDIX G

## CMOP CONTACT INFORMATION

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CMOP can offer technical expertise to analyze specific cofiring cases for gob gas producers interested in estimating gas valuations. To obtain such technical assistance, or for more information on coal mine methane recovery experiences, project potential, a full listing of reports, or program activities and accomplishments, contact::

Coalbed Methane Program Manager
U.S. Environmental Protection Agency
Atmospheric Pollution Prevention Division
401 M Street, SW (6202-J)
Washington, DC 20460

Facsimile: 202 565-2077
Email: fernandez.roger@epa.gov
schultz.karl@epa.gov

Homepage: http://www.epa.gov/coalbed

To Order Documents: Call 1-888-STAR-YES