DOE/MC/32186 -- 5147

Low NO_X Turbine Power Generation Utilizing Low Btu GOB Gas

Final Report
June - August 1995

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Work Performed Under Contract No.: DE-AC21-95MC32186

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
United Energy Development Consultants, Inc.
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DISCLAIMER

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ABSTRACT

Methane, a potent greenhouse gas, is second only to carbon dioxide as a contributor to potential global warming. Methane liberated by coal mines represents one of the most promising underexploited areas for profitably reducing these methane emissions. Furthermore, there is a need for apparatus and processes that reduce the nitrogen oxide (NO_x) emissions from gas turbines in power generation. Consequently, this project aims to demonstrate a technology which utilizes low grade fuel (CMM) in a combustion air stream to reduce NO_x emissions in the operation of a gas turbine. This technology is superior to other existing technologies because it can directly use the varying methane content gases from various streams of the mining operation. The simplicity of the process makes it useful for both new gas turbines and retrofitting existing gas turbines.

This report evaluates the feasibility of using gob gas from the 11,000 acre abandoned Gateway Mine near Waynesburg, Pennsylvania as a fuel source for power generation applying low NO_x gas turbine technology at a site which is currently capable of producing low grade GOB gas ($\cong$ 600 BTU) from abandoned GOB areas. From the US Bureau of Mines, Waynesburg, Sewickley, and Pittsburgh coal desorption data on the Gateway Mine was used in conjunction with mine maps from Jesmar Energy and geologic information from Pennsylvania's Bureau of Topographic and Geologic Survey to assess the remaining methane gas resource and model the reserve potential of the mine. Structure and pressure relationships were deemed significant in determining methane production rates, which are more than adequate to meet the turbine requirements of 1000 mcf/day.

A profitable process design using two 1700 kW gas turbines was based on using some mine ventilation air for the turbine combustion air, supplying waste heat to the SCI-Greene prison facility to replace natural gas currently used for comfort heating and laundry, selling electricity to the adjoining Lazarus mine, SCI-Greene, and West Penn Power, and producing and delivering the 60% methane gas at a reasonable price. The gob gas is diluted with inerts rather than with air which will reduce the emissions of nitric oxide when it is burned. The mine and prison requirements can be supplied at a price of $0.04 per kWhr as compared to the $0.046 that SCI-Greene, and probably the mine now pay. Excess power can be sold to West Penn Power at their energy cost of $0.017 per kWhr. Safety considerations, enthalpy and coalbed methane utilization, and a construction and operation plan were also addressed.

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UEDC would like to thank the people at the following organizations for their contribution to this effort:

Name	***Organization***
Patrick Diamond	US Bureau of Mines
Fred Garcia	US Bureau of Mines
David Damon	Consolidated Natural Gas
David Uhrin	Geologic consultant on coal desorption
Mark Leidecker	Jesmar Energy
Christopher Laughrey	PA DER Bureau of Topographic and Geologic Survey
James Bandish	Mining Safety and Health Administration (MSHA)

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I. Summary/Introduction

The Gateway mine (Pittsburgh seam), located in Greene County, Pennyslvania, was primarily mined by room and pillar methods, but prior to closing, long-wall mining methods were employed. While the Gateway mine itself has been closed, a new mine within the limits of the Gateway mine boundary has been opened (Lazarus), see Figure No. 12. This mine is located on extreme eastern boundary of the Gateway mine proper. The Lazarus mine has experienced high levels of methane "outbursts" from the seals of the Gateway mine.

The property is located within West Penn's electric grid and adjacent to Pennsylvania's State Correctional Institution, (SCI - Greene). This is a new facility and does have a large electric power and heat load.

UEDC evaluated the gas reserve and economic potential and ESA evaluated the turbine applications for this project. Overall, a project as outlined below will yield positive economics.

Mine Gas Potential

Based on UEDC's evaluation of the 8,735 acre abandoned mine, the following assessment was made:

- Approximately 50% of the Pittsburgh coal remains, but in addition, overlying coals which remain below cover are also present. An estimated total of 30 feet of coal remain. (See Table No. 8 below.)
- UEDC obtained desorption data from CNG (Consolidated Natural Gas) on two core holes drilled within the mine boundary in 1987. This desorption data, in additon to data obtained from the USBM, were utilized in estimating gas in place and reserve potential.
- An estimated 40 to 119 BCF of gas remain in place (see Figure No. 29).

UEDC used these mine measurements, as well as existing DOE, EPA, USBM, USGS, MSHA, and other pertinent government and industry data and documents relevant to domestic coal mine emissions, to assess the source and magnitude of the methane gas stream associated with the proposed project operation. The data is incorporated in the text of this Phase I Report.

Coal Mine Methane Reserves

UEDC developed an analytical model to predict gas production (reserves) as a function of GOB and atmospheric pressure fluctuations. This model utilized, as a basis, work performed by Foster and Miller[1] on behalf of the USBM and work by Layne[3],et.al.,. at the DOE (METC). The model incorporates desorption data which were provided by CNG. Several model predictions were performed at varying GOB and atmosperhic conditions.

- Estimated reserve potential ranges from 2 to 14 BCF.

Reserves are based on economic operating conditions, i.e., operating and maintanence costs with respect to revenues from gas sales. UEDC utilized no inflation factors for gas revenues in the reserve assessment. Reserves were projected for 25 years only. (Practically, the impact of revenue beyond 15 years does not have a large impact on IRR- interal rate of return.)

Currently, three vent (gob) wells are emitting over 1,000 MCFD to the atmosphere; by the installation of the GOB/turbine system, this will be elminiated. In addtion, once the infrastructure in installed, incremental addtions of waste gas can then become practical.

Capital investments for drilling, construction of pipelines and compression were obtained from Jesmar, and Cardinal compression. UEDC feels that the capital cost numbers are realistic and overall economics are conservative, i.e., no gas price inflation. A summary of the economic assumptions are presented in the economic section below.

UEDC evaluated drilling only 10 and 20 GOB wells to achieve these reserve projections. The reason for this is that as the gas desorbs from the overlying coals, the desorption rate decreases with respect to the cumulative gas molecules remaining to be desorbed. Therefore drilling of additional wells may not be economically prudent. An example is presented below.

UEDC utilized a 60% GOB quality based on the fact that the Gateway mine is closed. In normal mining operations, the GOB gas quality is affected by atmospheric pressure fluctuations of mine air leaking across seals into the GOB. Conversely, if an insufficient number of GOB or VVH wells have not been drilled to reduce the methane and pressure accumulation from the overlying desorbing coals, methane from the GOB will invade the mine, therefore increasing methane concentrations above those permitted by MSHA.

UEDC evaluated the methane gas reserve associated with the abandoned mine for the proposed project to characterize the potential fuel or feedstock source. This effort included an assessment of :

1.) *existing methane drainage techniques (including gob-well vent systems)*, - An excellent study performed by the USBM[2] (Garcia, et.al.) evaluated methane emissions from Gateway and its affect on the Lazarus mine. UEDC developed an analytical model to predict methane emissions across the seals based on this work. As mentioned, three relief boreholes exist on the mine.

2.) *opportunities for improving methane drainage effectiveness*, - UEDC expects that by drilling 10 to 20 additonal GOB wells, substantial volumes of methane will be produced thus reducing methane "outbursts" into adjacent mines.

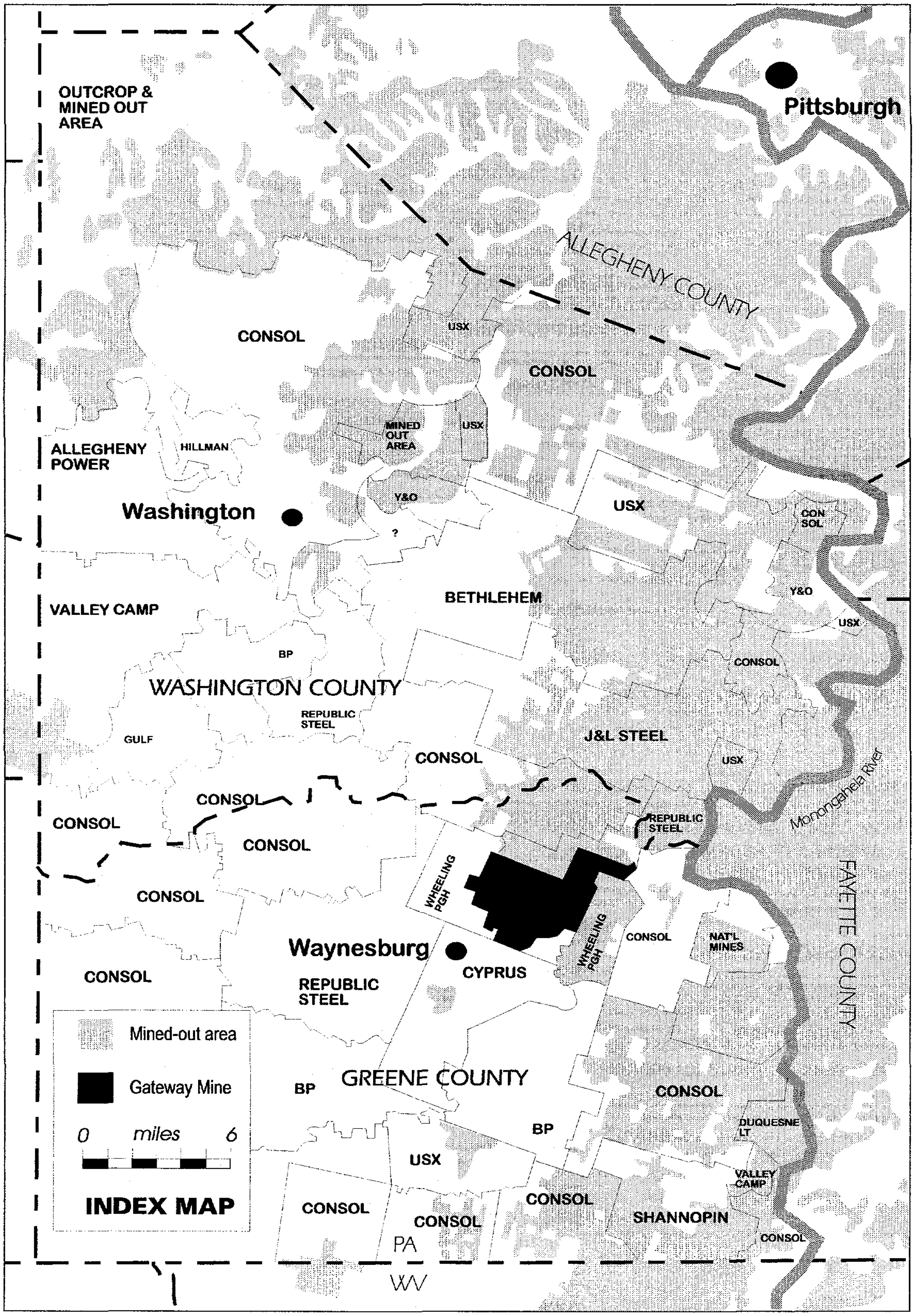
3.) *coal mine characteristics*, - A detailed geologic evaluation was performed by UEDC in order to evaluate overlying coals, depth of cover and topographic constraints on drilling and methane development. Topographic considerations will limit or effect the cost of development. This is included in the geologic section.

4.) *environmental considerations*, - UEDC feels that by implementation of this project, substantial volumes of methane emissions will be precluded in future years (>100 BCF) and the impact of adjacent mines to methane outbursts will be reduced.

and

5.) *gas ownership implications*. Jesmar has leases on the Gateway Mine property to drill and develop GOB gas. There are no adverse ownership implications.

Figure 1: Index Map



Technology Application

Design Trade-Off of Cost --

The cost of the electricity is a function of the capital cost, the cost of money and the life of the project, the operating and maintenance costs, the use of methane in mine ventilation air for part of the fuel, and the use of part of the waste energy from the gas turbine to replace fuel as a heat source (cogeneration). This preliminary evaluation resulted in a process design which would be profitable. The process is based on using some mine ventilation air for the combustion air for a turbine, supplying waste heat to the SCI-Greene facility to replace natural gas that is currently used for comfort heating and laundry, selling electricity to the Lazarus mine, to SCI-Greene, and to West Penn Power, and producing and delivering the 60% methane gas at a reasonable price.

Supplying all of the mine and prison requirements at a price of $0.04 per kWhr as compared to the $0.046 that SCI-Greene, and probably the mine now pay, and selling power which is produced in excess of that being used by these two customers to West Penn Power at their energy cost of $0.017 per kWhr becomes the foundation for the profitable operation. Two gas turbines of 1700 kW each were chosen so that when one was out of service the other would be large enough to operate both the prison and the mine. The lower-priced electricity would be about 50% of the total when both turbines are operating, but since no electricity will be sold to West Penn Power when one of the units is out of service, the total sold at the lower rate will be about 42% over the year.

West Penn Power has excess capacity and only pays for avoided fuel cost so they should be paying a constant rate for delivered power irrespective of the swings in the delivery rate. Initially, West Penn Power will receive 42% of the electrical power but will supply only 23% of the electrical revenue. But as the SCI and mine loads increase, sales to West Penn will decrease, as discussed in the economics section. Of the total revenues, including the thermal sales to SCI-Greene, West Penn Power will supply only 20%. Nevertheless, at this time it seems best to size the equipment so that the prison and mine power will need to be purchased from West Penn Power at only rare times, since it is anticipated that significant demand charges will be made.

With the thermal load at SCI-Greene, it seemed important to locate one turbine there so waste heat could be recovered and used to replace the natural gas that is currently used for heating, laundry, and thermal loads. The approximately 6.55 miles between the prison and the Lazarus mine is probably too far to transport steam or ventilation air. Since one of the turbines would have more than enough waste heat to supply the heating load, it is not necessary to locate both turbines at SCI-Greene. The other turbine would be located at the mine where it could use ventilation air and save on fuel by burning the methane in the ventilation air. Electrical lines would be needed between the two turbines so that either could supply the mine or the prison and so that only one connection to the power company would be required.

With the above arrangement, the average price of electricity would be $0.030 per kWhr. At this average sale price, with 10% of the energy being supplied through the ventilation air, at no cost, and an additional $116,400 per year coming from the sale of recovered thermal energy, the operation would break even at a burner tip gas price of $1.50 per million Btu.

Other designs may also work, but this seems to be a very attractive design to consider. This will be evaluated in Phase II (final design).

Cost Per kW-hr of Electricity

The cost per kWhr of electricity is found parametrically, based on the fuel price, total plant capital cost, and the amount of energy obtained from the ventilation air. Three of the figures in Section III show electrical price as a function of burner tip gas price. In general, it would seem to be very difficult to generate electricity for West Penn Power's avoided cost of $0.017 per kWhr. The price paid by SCI-Greene, $0.047 per kWhr, would allow a plant to pan the necessary costs for the gob gas and sell electricity at a profit.

Electricity Sales --It is anticipated that SCI-Greene will soon be filled to capacity and at that time the electrical and thermal energy demands will be 25% greater than they were in the last part of 1994 and the first part of 1995. At that point it is expected that the demand would average 1375 kW. By comparing some of the mine parameters to some other mines, we have estimated that the Lazarus mine uses 300 kW of electricity. The total of these are the estimate of the higher priced electrical sales.

West Penn Power has sufficient capacity and is not paying for capacity. They are paying the avoided cost of $0.017 per kWhr. This price is probably not high enough to justify a gas turbine power plant if West Penn is the sole customer. However, the power company would be obliged to buy any amount of power offered at this price.

Safety Considerations --

The most important safety consideration is that neither the mine nor the plant suffer a power interruption. Even though we plan for a back-up gas turbine, some third source will be required. Perhaps the mine, the prison, or both now have emergency power generators which could supply power in case both turbine-generator sets were out of service. Otherwise, the mine and prison will need to remain connected to West Penn Power for emergencies.

Procedures will be implemented to insure that the gob gas does not infuse air to a degree that will cause it to be explosive. It would need to draw in about 6 times its volume of air before there would be enough oxygen to make the mixture explosive.

The ventilation air is very dilute and not over 1% methane. The lower explosive limit of methane is five times this value. The safety of the mine and the miners depends upon maintaining the methane in the ventilation air at a safe level. The mine, by law, uses continuous analyzers to assure that the ventilation air does not reach explosive limits.

Enthalpy and Coalbed Methane Utilization --

The gob gas is diluted with nitrogen, carbon dioxide and other gases, with very little oxygen. The gob gas has 43 to 62% methane. This is sufficient for almost all uses; however, it is not of pipeline quality. It must, therefore, be improved or used within a short distance of its origin. With 400 to 650 Btu per cubic foot, this gas is excellent gas turbine fuel. The fact that it is diluted with inerts rather than with air will reduce the emissions of nitric oxide when it is burned.

Ventilation air has 0.25 to 1.0% methane in it. This methane is as useful as any other methane as long as there is a requirement for a fire big enough to consume all of the ventilation air. Gas turbines operate with a large excess of air, and as such would use more ventilation air per unit of electricity produced than other power systems. With the system planned, we would use only about 20% of the ventilation air from the Lazarus mine. The air has 0.6% methane in it and would supply about 22% of the energy for a turbine in which it were used. The ventilation air with methane in it distributes part of the combustion to areas where the temperature will be much lower than the temperatures where nitric oxides are formed. This will reduce the No_x emissions.

Business Plan to Build/Operate --

The proposed project plan is summarized below. At this stage of the project, negotiations are required to be completed.

Project economics include electric power sales to West Penn Power at distressed (avoided) rates and to non-regulated entities. Positive economic results were achieved, under different risk assessments. The most likely case IRR is 23.3%.

The operation as envisioned here would be economical as a result of the electrical and thermal energy sales to SCI- Greene. In the text it was presented as break-even when the gob gas was available at the burner tip at $1.51 per million Btu. Another way to express this would be as payout period. Without showing capital recovery nor interest payments, the net revenue per year divided into the capital cost would give the payout period. Using the example in **V., C. Turbine Economic Evaluation**, and the $1.51 per million BTUs the payout period is 7.5 years. The general relationship with all of the fixed conditions given above is:

Payout in years = 9.4/(2.77 - Fuel cost in $/million Btu)

Burner Tip Gob gas price $/MMBtu	Payout, years

$0.00	3.4
$1.00	5.3
$1.51	7.5
$2.00	12.2

From this, one can see that even with the cogeneration, the ventilation air, and the favorable electrical rate, gas prices of around $2.00 per million Btu probably cannot be supported. Thus, this operation could not afford to purchase its main fuel supply from a pipeline supply. Also, if the gob gas was of a quality to enter a pipeline, this power production might not be competitive with such a use of gob gas.

However, the use of this process is not dependent upon prisons or other outside power users, as attractive as they might be. Some mines are much larger than the Lazarus mine and may use as much as 3,000 kW. An economical process which involved only the mine could be arranged. The mine would supply the gob gas and the ventilation air and use the power.

It is hard to envision how the process could be developed with a local power company which has low cost power from inexpensive coal as the power purchaser. An operation where the power is wheeled through the local power company and sold at a higher price to some remote company, probably located in a region where little or no coal is mined, would be attractive.

These gas turbines in the range of 500 to 4,500 kW are readily available and find many uses in power production all over the world. They are used to supply power for remote villages, for military operation, for industrial uses, and point on large power grids where a small amount of power is needed for voltage or phase angle control. Most of them are outgrowths of aircraft jet engine manufacturing and are very reliable. GE produces small gas turbines as an outgrowth of their aircraft engine operations. Solar, Allison, Royals Royce and others produce gas turbines in this size range as a result of their aircraft engine experience.

ABB produces and sells a gas turbine with low NO_x burner where the natural gas fuel is introduced into the combustion air all along the combustor can. This process functions thermally, and kinetically the same as the process patented in US Patent 5,216,876 and would have the same safety but NO_x emissions problems.

The use of ventilation air with a methane component as the combustion air for a gas turbine will reduce the emissions of coalbed methane. This is an economical and nonintrusive method of reducing greenhouse gases. It is also environmentally helpful since it replaces the use of other fuel which must be produced and burned to produce power.

In terms of the greeenhouse effect, the use of gob gas has the same advantage as using the ventilation air since much of the gob gas is vented to the atmosphere without incineration.

The particular gob gas which was found in the Gateway mine residue is diluted with inerts. This will have a reduced flame temperature and will produce less NO_x. The use of ventilation air also reduces NO_x formation. With these two energy sources we twice reduce methane emissions and we twice reduce NO_x emissions.

The business and development plans incorporate the following :

Revenue

Electric sales to

1. Lazarus Mine
2. SCI
3. West Penn (excess power at destressed price)
4. Heat load to SCI.

Project Development

1. Drill 10 to 20 wells
2. Install two (2) 1.7 MW turbines

II. Background/Methodology

A. Desorption

Desorption data for the Pittsburgh, Waynesburg, and Sewickley coals were obtained from CNG. These tests were performed in late 1987 in cooperation with Gateway Mine personnel. The principal purpose for obtaining the cores by Gateway was to evaluate the coal for ongoing mining operations. CNG requested and obtained permission to obtain desorption data for internal studies. Mr. David Uhrin performed the analysis for CNG. The desorption data is summarized on the following tables. The cores were obtained in actively mined areas and the resulting gas content was lower than expected from virgin areas, but this data was used for resource predictions in this evaluation because they represent the state of coals in the GOB areas.

The data obtained is evaluated, tabulated, and presented to microscopically evaluate the desorption mechanisms and their relationship to anticipated well performance with atmospheric and gob pressure variations. Much has been written and summarized with respect to the properties of coal. The development of the GOB Well Analytical incorporates concepts previously presented. A summary of these studies follows:

1. Background

a) Physical Structure Of Coal

Coal is generally considered to be a dual porosity system very similar to that described by Warren and Root. Coal is made up of matrix elements, surrounded by orthogonal fracture (commonly called "cleats").

(1) Coal Matrix Properties

- The coal matrix contains a very fine micro-pore structure with pore diameters of 5 to 10 Angstroms.
- The coal matrix provides a very high storage capacity for methane gas. Methane molecules are physically attached (i.e. adsorbed) to the micro-pore walls of the coal matrix.
- The amount of gas stored in coals is quite large compared to single-porosity gas sands. A typical concentration of adsorbed methane is about 15 scf/cu ft (375 scf/ton) of coal which is equivalent to a porosity of 51% at 400 psi and a porosity of 13% at 1600 psi. Thus, the coal matrix contains 90 to 100% of the stored gas in coal seams.
- Flow through the coal matrix is a diffusional process; i.e., some combination of molecular, Knudsen and surface diffusion.
- The coal matrix has an extremely low flow capacity. In terms of an effective diffusion coefficient, values range from about 10^-6 to 10^-9 ft^2/day.
- By equating Fick's Law of Diffusion with Darcy's Law, it is possible to obtain an equivalent permeability; the diffusion coefficient range given above corresponds to a permeability range of 10^-9 to 10^-12 md at a pressure of 400 psia.
- Due to the low flow capacity but very high storage capacity of the coal matrix, a "dual-porosity" reservoir model is required in order to accurately represent the flow behavior of coalbed methane wells.
- For water-saturated seams, a dual-porosity model can correctly predict the negative gas production rate decline associated with these wells.

(2) Coal Fracture Properties

- Coal seams are characterized by a regular fracture network commonly referred to as a "cleat system."
- The cleat system consists of two essentially perpendicular sets of fractures. the more pronounced set of fractures or fissures is known as the "face cleat" system, while the less pronounced or secondary set of fractures is called the "butt cleat" system. The face cleat

system is generally continuous whereas the butt cleats often terminate at intersections with face cleats.

- The face and butt cleats provide a low volume, relatively high permeability flow network. the permeability of the cleat system typically ranges from one to greater than 50 millidarcies.
- The cleat system must intersect a wellbore and/or hydraulic fracture in order to provide a productive well.
- The porosity of the cleat system is low; typically 1 to 4% (e. g., 2% porosity, 40-acres and a 5 ft. coal seam gives a cleat volume of 174,240 bbls.).
- The clean system normally contains a high water saturation at initial conditions (90 to 100%); therefore, gas storage in the cleat system is very small (typically less than 10% of total gas in-place).
- Short term well tests (e. g., slug injection tests, interference test, etc., of 1 to 30 days duration) can be used to determine the permeability of the cleat system.

(3) Coal Cleat Characteristics

- Coal cleats or fractures provide flow paths to a wellbore or induced fracture.
- According to Ertekin and King, the major cleat system is believed to have dimensions on the order of microns (1 micron = 10^-6 m or 0.0001 cm).
- Dabbous, Reznik, et. al. reported equivalent pore radii of 0.01 to 200 microns based on capillary pressure measurements on samples of the Pittsburgh coal.
- By comparison, micropores within the coal matrix have pores as small as 5 to 10 Angstroms (1 Angstrom = 10^-8 cm).
- Since the cleat systems in most coal seams are water saturated, a two-phase (gas-water) flow regime exists during most of the producing life of a coal gas well.
- The flow of gas and water in the coal cleat system is described in terms of Darcy's Law.

b) Origin of Darcy's Law

- In 1856, a Frenchman named Henry Darcy investigated the flow of water through sand filters for water purification.
- Darcy's objective was to quantify the flow rates that could be obtained for various diameter sand packs and applied pressures.
- Darcy discovered that, for vertical flow of water through a given sand pack, there was a proportionality constant (k) between flow rate per unit area (Q/A) and the applied pressure gradient; i.e.

$$Q/A = k \ (h1 - h2) / L$$

Where:

h1 - h2 = net hydrostatic pressure across sand pack
L = length of sand pack

(1) Assumptions in Darcy's Law

- This relationship became known as Darcy's Law and was found to be applicable to flow in any porous media (consolidated or unconsolidated), provided the following assumptions hold:
  1) A single-phase fluid of constant viscosity completely fills the connected pore volume of the porous medium
  2) Conditions of viscous or laminar flow exist throughout the complex inner pore structure of the porous medium
- These assumptions are identical to those of Poiseuille's Law for flow through capillary tubes. A convenient form of Poiseuille's equation is:

$$Q/A = r^2/8 \ (P1 - P2) / (mu \ L)$$

Where:

r = radius of circular tube
mu = viscosity of fluid

L = length of tube
P1 - P2 = pressure drop across length, L

c) Diffusional Flow

Flow through the coal matrix is a diffusional process which can be described by Fick's Law. Due to the low flow capacity but very high storage capacity of the coal matrix, a "dual-porosity" reservoir model is required.

Diffusion - Basic Concepts

- Diffusion is the process whereby matter is transported from one part of a system to another as a result of random molecular motions.
- Diffusion of methane molecules occurs within the microporous structure of the coal matrix.
- Consider a slice of coal matrix between face cleats as in the following figure. For purposes of illustration, the matrix is subdivided into a high and low concentration region, as would exist in the reservoir during depletion.
- Since the concentration of methane molecules in the left half is greater than on the right, there will be a net transfer of molecules from left to right; i.e.,
  - A. Due to random molecular motion, the same fraction of existing molecules will cross from left to right and from right to left.
  - B. Since there are more molecules in the left partition, there will be more molecules moving from left to right than from right to left, giving a net flow of gas due to the concentration gradient.
- Diffusion in the micropores of coal matrix can occur via three mechanisms
  1) Bulk diffusion, where molecule-molecule interactions predominate (as described above)
  2) Knudson diffusion, where molecule-surface interactions predominate, or
  3) Surface diffusion, where adsorbed molecules migrate along the walls of the micropores
- Regardless of the type of diffusion, Fick's Law is used to describe the resulting mass transport.
- Fick's Law can be simply stated as follows: The rate of flow of a substance per unit area is directly proportional to the concentration gradient normal to the direction of flow.
- The proportionality constant in Fick's Law is called the "diffusion coefficient" and is denoted by "D."

$$Q/A = -D \; dC/dX$$

- The coal matrix can be modeled as a "lump" having a single average methane concentration, or, alternatively, as a continuum.
- In the latter case, the matrix must be subdivided into 10 to 15 discrete subelements in order to numerically solve for the diffusion of methane to the cleat faces.
- It has been shown by Kolesar and Ertekin that the "lump" approach is sufficient for most practical engineering purposes.
- Treating the matrix as a single entity (so far as methane concentration is concerned) is precisely the classical Warren & Root pseudo-steady-state (PSS) flow assumption.
- King, Ertekin, and Schwerer have shown that the PSS flow rate of methane from matrix to fractures can be expressed in terms of a "sorption time", the boundary concentration, and the average matrix concentration.
- Sorption time is a function of the matrix size and shape and the effective diffusion coefficient, D, discussed above.

d) Adsorption/Desorption Mechanisms

Adsorption is the "adhesion of a single layer of gas molecules to the internal micro-pore surfaces of the coal matrix."

Desorption is "the process whereby adsorbed gas molecules become detached from pore surfaces and take on the kinetic properties of free gas." The above concept of "physical adsorption" must be distinguished from "chemisorption" in which chemical bonds are formed.

- Langmuir developed a very simple theory of physical adsorption by assuming that the solid surface is capable of holding a layer only one molecule thick.
- Langmuir postulated the following:

A) The rate of adsorption is proportional to the rate of collisions with the surface, which, in turn, is proportional to the gas pressure (P) and to the fraction of the surface (1 - F) which is unoccupied by adsorbed molecules; i.e., Rate of Adsorption = K1 . P . (1 - F)

B) The rate of desorption is proportional to the fraction of surface occupied (F); i.e., Rate of Desorption = K2 . F At equilibrium, the two rates must be equal, which gives
F = K1 . P/ (K1 . P + K2)

- Observing that the mass of gas adsorbed per unit mass of the solid (C) is proportional to F (i.e. C = K3 . F) gives, after some manipulation,
  C = AP/ (1 + BP)
  Where "A" and "B" are constants.
- The above relationship can be put into the form of a <u>linear equation</u> by the following rearrangement:
  P/C = 1/A + (B/A) . P
- However, the concentration vs. pressure relationship is more commonly presented in the form:
  C = VL . P/ (P> + P)
  Where
  VL = A/B and PL = 1/B
  The parameters "VL" and "PL" are known as "<u>Langmuir Coefficients</u>."
- The Langmuir coefficients have the following characteristics:
  VL = Maximum adsorptive capacity; i.e., the upper limit of adsorption as pressure approaches infinity
  PL = Pressure at which adsorbed gas concentration is one-half the maximum; i.e.,
  C = VL/2

(1) Desorption of Methane in Coal Seams

Desorption occurs in coal seams at the cleat-matrix interface due to pressure reduction in the cleats. As molecular diffusion occurs from within the coal matrix, desorption also occurs at the internal micro-pore surfaces. the adsorptive properties of individual seams depend upon the chemical nature of the coal. In general, the sorption capacity increases with the fixed carbon content of a coal and also with depth.

- Adsorbed gas on the internal micro-pore surfaces accounts for a very large percentage of the total gas content.
- According to Kolesar and Ertekin, the internal surface area of the coal micro-pore structure is typically 100 to 300 m^2/gm.
- The simple equilibrium theory of Langmuir indicates that adsorption (increasing pressure) followed by desorption (decreasing pressure) should give identical results provided sufficient care is taken to obtain equilibrium at each pressure.

(2) Desorption Pressure and Gas Content

It is possible for coal seams at "virgin" conditions to contain much less gas than the appropriate isotherm would predict at initial coal seam pressure.

- <u>desorption pressure</u> is that pressure at which gas desorption begins, or alternatively, that pressure above which no gas is liberated from the coal.
- When gas content is known, desorption pressure, Pd, may be obtained by observing the pressure corresponding to the gas content on the <u>desorption</u> isotherm.
- Alternatively, if desorption pressure is known from well tests, then gas content can be determined by the corresponding point on the desorption isotherm.
- In extreme cases, desorption pressure may be less than 30% of the initial reservoir pressure.

e) *Mechanisms of the Ventilation of Sealed GOB's*

Abandoned underground coal mine areas must either be sealed or ventilated to comply with federal mine regulations. Ventilation of these abandoned areas is often impractical due to roof falls and inadequate primary mine ventilation. If the area is sealed, a very complex ventilation system is set up, in which the gob "breathes" in and out due to barometric pressure fluctuations. *Foster and Miller*[1] under contract to the USBM developed a simulation methodology to predict air flows into and out of a sealed mine area. This is important in order to reduce methane in the returns and reduce spontaneous combustion potential within the sealed area, and minimize the amount of time that the gob gas is in the explosive region. This work provides the fundamental principles upon which the mechanisms of GOB production are described below.

Sealing abandoned mine areas can reduce the primary ventilation required to maintain safe methane levels in bleeders and returns, when ventilation boreholes are used. Sealing can also reduce the potential of spontaneous combustion in abandoned mine areas by reducing barometric-induced airflow. Prediction of the benefits of sealing an area has in the past been mostly guesswork. Unsafe methane levels in returns, spontaneous combustion, and explosive gas mixtures can still occur in sealed areas.

(1) Governing Equations:

The flow into and out of a gob area will obey the laws of the conservation of mass (mass flow in = mass flow out). This flow has been observed to be linear with respect to change in pressure across the seal in American coal mines. This linearity follows Darcy's basic flow laws for horizontal flow even at the low pressures which were observed across the seals (normally measured in inches - Water gauge -Wg.).

Figure 2: Sketch of a Simple GOB Area.

Pressure - **P**
Volume - **V**
Gas Make - $\mathbf{Q}_m$
Density - $\wp$
of gob gas

Leakage Flow OUT $Q= C(P-P_v)$

C = Seal Leakage Constant
P_v = Mine Ventilation Pressure

Gas flow into and out of a sealed gob area will obey the laws of conservation of mass.

$$DMass / dTime = \wp * (Q_m - Q)$$

where;

Q_m= Gas Make (methane desorbing from adjacent coal strata)
Q = Quantity due to pressure across the seal

Given the Universal Gas Law;

$$PV = MRT \quad \text{or Moles (M), } M = [PV / RT]$$

Therefore;

$$[V / RT] [d / dt (P)] = \wp \times [Q_m - C(P-P_v)]$$

$$[dP / dt] = \wp \times [RT / V] \times [Q_m - C(P-P_v)]$$

The change in pressure with respect to time may be broken down into two major variables: gas make (A1) and time constant (A2).

$$[dP / dt] = A1 - A2 * (P - Pv)$$

where;

$$A1 = [\wp * R * T]/ V * Qm = [P/ V] * Q_m$$

and

$$A2 = [\wp * R * T]/ V -* C = 1/Tau(\tau)$$

Integration of the above equations for actual barometric data (P_v) results in the calculation of the gob pressure. Conversely, if the gob pressure has been measured, the seal leakage coefficient (C) may be determined. Flows into and out of the sealed area may be determined with the following flow equation during the integration process:

$$Q = [A2 * (P - Pv) * V] / P_{avg}$$

where; average pressure (P_{avg}) is determined from the gob's elevation

These equations describe the pressure (P) inside the gob area and the leakage flow (Q) into and out of the gob area. The gas make (Q_m) of a gob area is very small in relation to barometric induced flows. The primary effect of gas make (Qm) is on the gob gas methane concentration. The governing variables in the above equations are the barometric pressures, and the time constant of the gob (τ).

The time constant of the gob (τ) is determined by the volume of the gob (V), the seal quality (C), and the gob pressure (P). The time constant of the gob area determines how long it takes the gob pressure (P) to respond to the driving function (barometric pressure, P_v). The greatest flows into and out of a gob area occur when the gob pressure is lagging behind the barometric pressure (delta pressure across the seals is large).

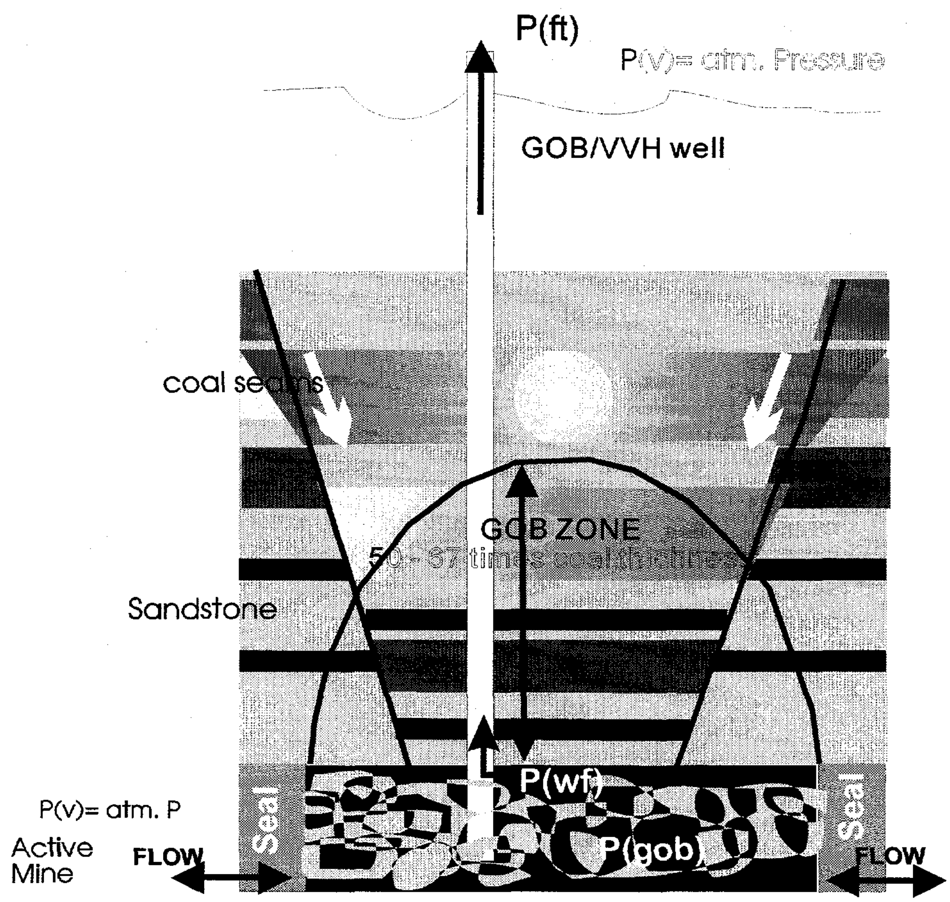
Barometric induced flows into and out of complex gob areas (Several interconnected areas, openings on multiple returns, boreholes, etc.) obey the same general principles as simple gob areas, with slight modification and rearrangement of the equations.

This is the simple form of Darcy's horizontal flow equation which is a linear plot of Q vs P(f), {(Pgob-Pv)/Pavg}. The slope is equal to C (leakage coefficient) in the case of the gob or in the petroleum engineering case $kA/ \mu L$. Where:

k = permeability
A = cross sectional area
μ = viscosity
L = length

The following Figure No. 3 shows a GOB well in schematic. The flow across the seals is related to the barometric pressure P(v) and the gob pressure.

Figure 3: GOB Well Schematic



Q = C * (Pgob-Pv)/Pavg

Changes in barometric pressure will either cause gob gas to flow from the gob into active mine workings or up the GOB/VVH well to be vented at the surface or both. Flow up the borehole is controlled by the P(gob), friction and gas head, seal coefficient, and mine ventilation pressure. Methane concentration in the gob will continue to increase as a function of the desorption characteristics of overlying strata, coals etc. Gas migration into the gob is through induced fractures from collapse of the roof, uncased well bores penetrating overlying strata and in communication with the GOB. Total methane emissions from the mine is described by the following:

$$Q_{(t)} = Q_{(ug)} + Q_{(vvh)}$$

Where:

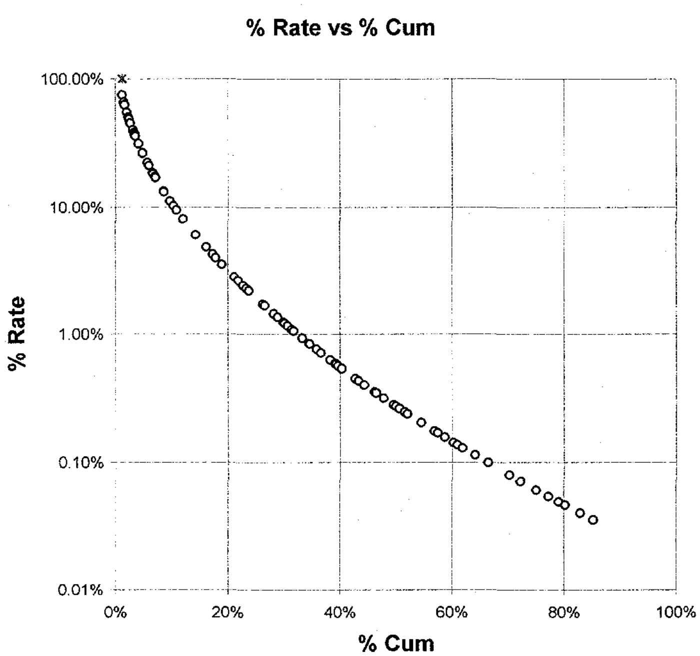
$Q_{(t)}$ = total methane emissions
$Q_{(ug)}$ = underground methane emissions
$Q_{(vvh)}$ = methane emissions via gob or vvh wells.

Underground methane emissions are directly related to P_v, P_{gob}, P_{mine} and C (seal coefficient). P_{mine} which are controlled by the amount of ventilation installed in the mine. During very low barometric pressures, if the differences in pressure (P_{ft}-P_{wf}) of the gob well are less than the P_{gob} across the seal, then the mine will experience outflows of gob methane into the mine workings. Conversely, if gob well pressure is greater than the seal pressure differential pressure, mine ventilation air will inflow into the gob and reduce methane concentration.

f) Effect of Non-homogeneous Factors

It has been shown[4] that unless a reservoir is known to be homogeneous, the unit-recovery factor should be corrected for the fact that depletion may progress more rapidly in the higher permeability (desorption) gas bearing zones than in the lower quality zones. Also, it has been shown that the fractional production rate from all layers can be related to the cumulative production from all layers as a fraction of the total gas in place for all layers (see Figure below). Desorption data in the following section was evaluated to determine if this relationship is applicable to coal desorption data.

Figure 4: Rate vs. Cum Relationship Non-homogeneous Production

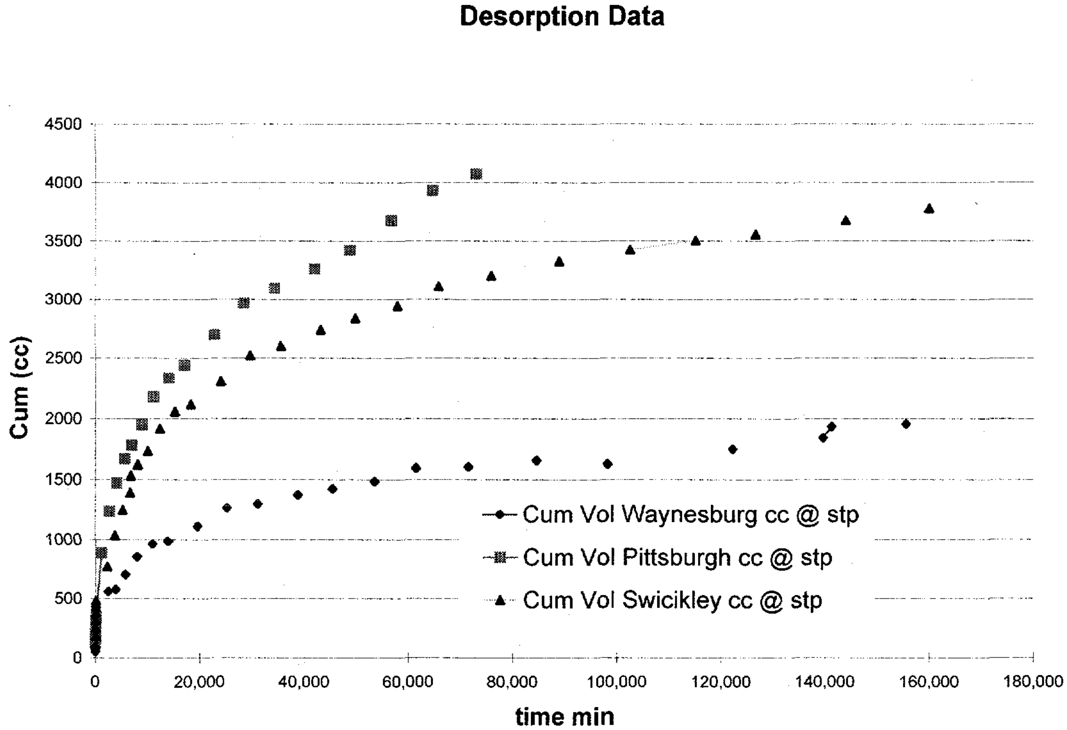


2. Desorption Data Analysis

As mentioned, desorption data was obtained by CNG in cooperation with Gateway Mine personnel. Mr. David Urhin conducted tests on the cores on behalf of CNG. The data is presented in tabular form on Table 1: to Table 3: .

The following Figure 5: shows cumulative volume with respect to time. As mentioned, the Pittsburgh desorption was curtailed due to mine requirements for the core for other analyse.

Figure 5: Desorption Data Cum (cc) vs. Time



The following Figures Nos. 6, 9, 10, and 11, are graphs of the (dQ) flow rate(cc/m) vs. time for the desorption data. As expected, the incremental flow rate decreases with time. This decline in very much like decline from conventional gas or tight sand production. The production decline can either be hyperbolic or exponential in its decay as described by Layne[3].

Figure No. 7 shows the rate relationship with the P(f). The pressure function is defined as the $(P - P_v)/P_{avg}$ for the core samples. Desorption rates are very small with respect to the P(f). This function used in the evaluation of mine data, which follows, is defined as $(P_{(gob)}-P_{(v)})/P_{avg}$. $P_{(avg)}$ used for the mine analysis is the pressure at elevation for the mine.

Figure No. 8 shows the relationship of the cumulative desorption volume with respect to rate as of percent of initial rates. As shown, a fit of the data presents a reasonable fit of all the data plotted. This equation was used as the basis for the analytical model used below to predict gas production with respect to the pressure function.

Figure 6: Desorption Flow (cc/m) vs. Time

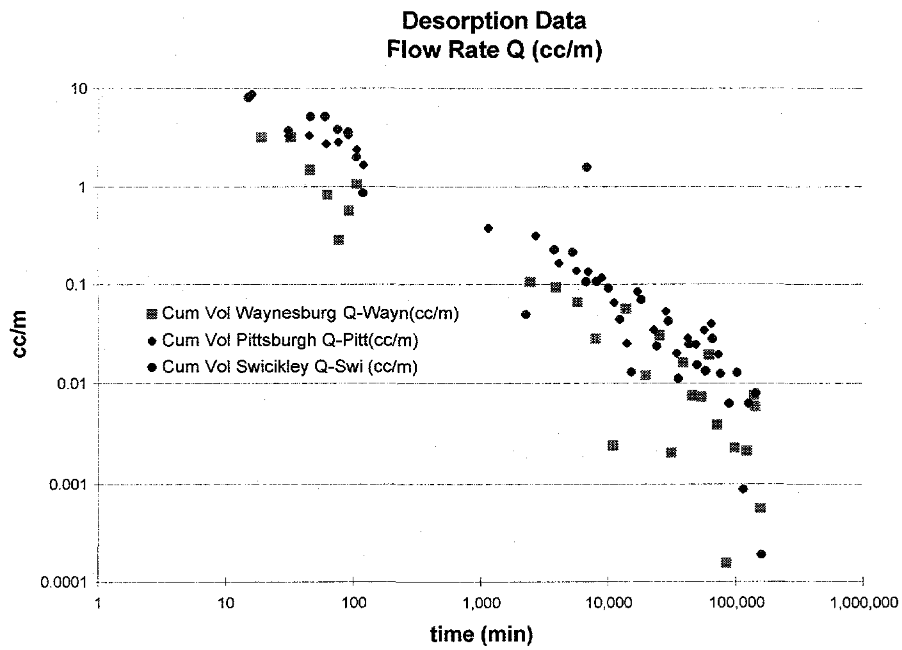


Figure 7: Desorption Data Cum (scf/d) vs. P(f)

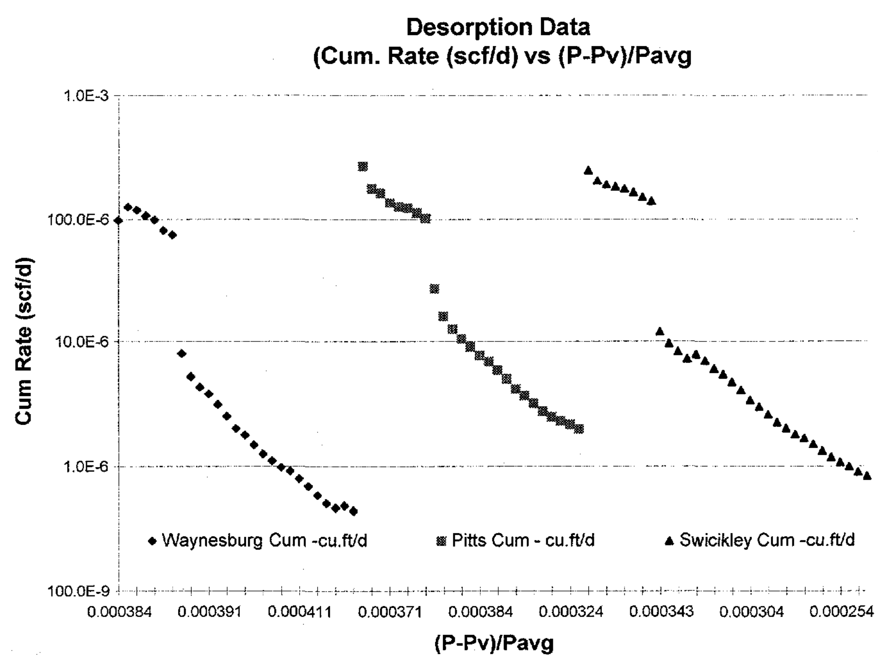


Figure 8: Desorption Data % Rate vs. % Cum

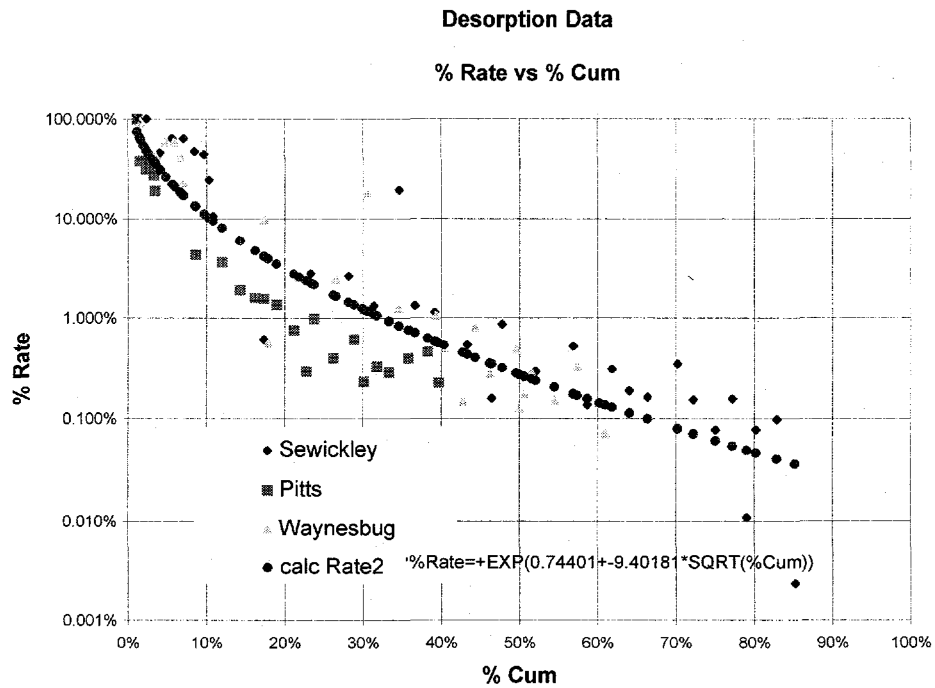


Figure 9: Pittsburgh Data Rate vs. Time

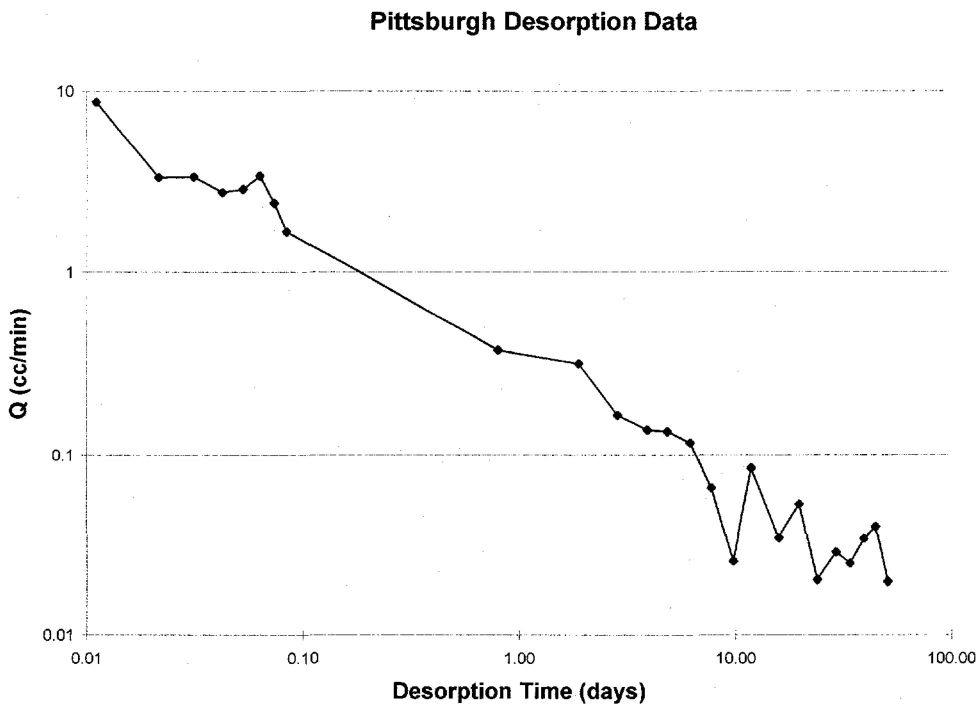


Figure 10: Waynesburg Data Rate vs. Time

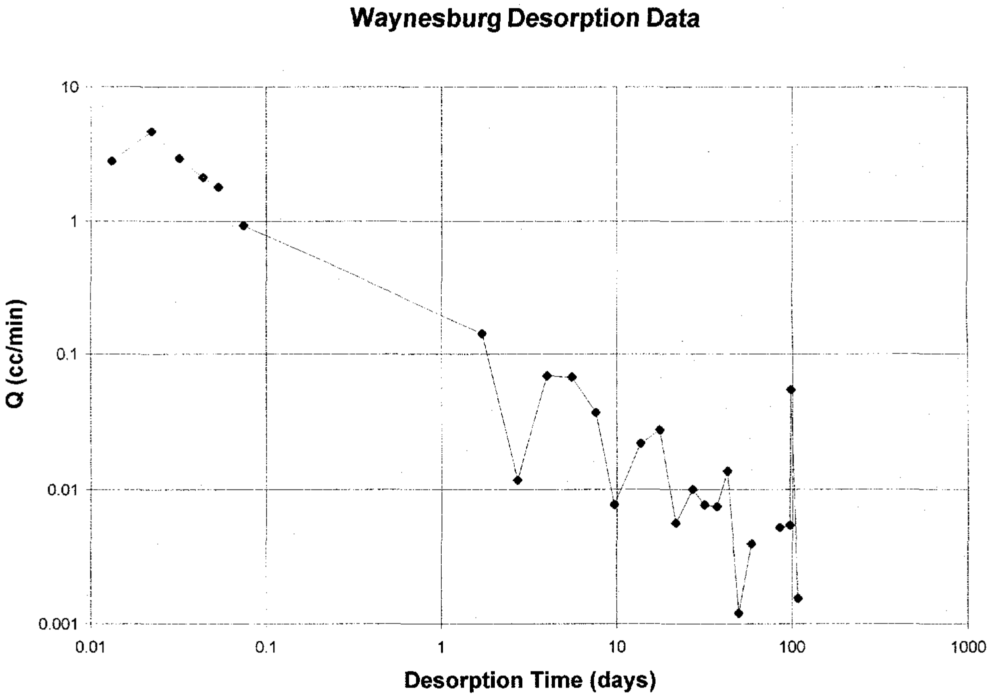


Figure 11: Sewickley Data Rate vs. Time

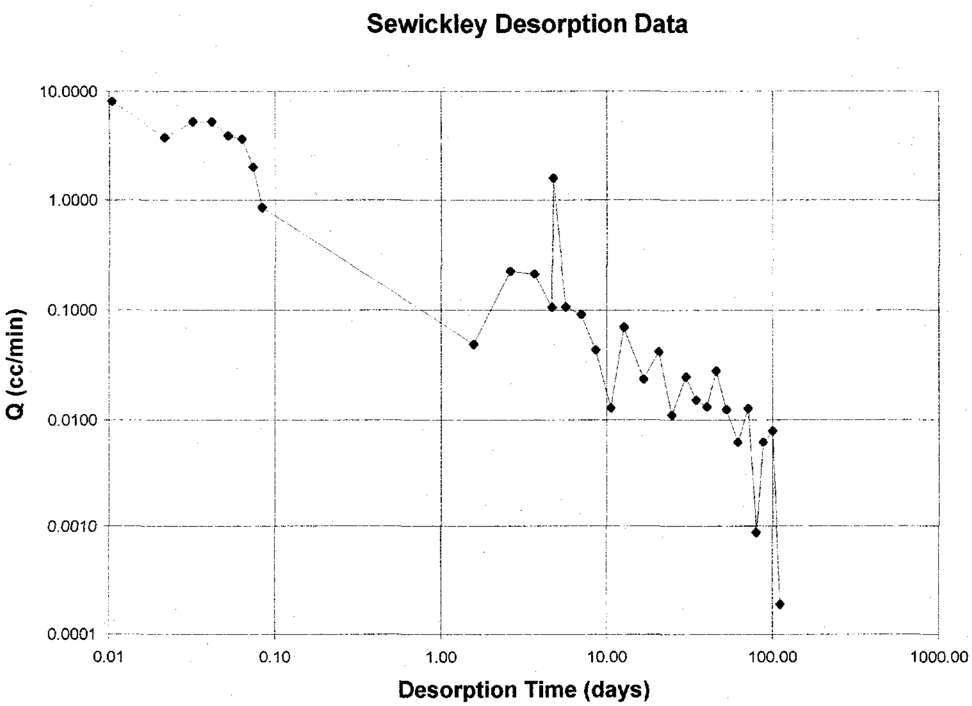


Table 1: Waynesburg Desorption Data

GATEWAY COAL COMPANY PROPERTY
GREENE COUNTY, PENNSYLVANIA
DESORPTION TESTS AND ANALYSES

WAYNESBURG

	ID No. 6D157826		Weight of Core gms		1768				
Date	Atm. pressure cm Hg	Temp. Deg. F	Volume Measured cc	Volume Corrected cc @ stp	Volume Accumulated cc @ stp	Volume Before STP	Time	Elapsed Time Days	Hr:Min
7/30/87	73.05	90	61	53	53	61	18:17	0	0:19
7/30/87	73.05	88	42	61	114	103	18:30	0	0:32
7/30/87	73.05	86	21	41	155	124	18:44	0	0:46
7/30/87	73.05	84	14	36	191	138	19:01	0	1:02
7/30/87	73.05	82	4	25	216	142	19:15	0	1:16
7/30/87	73.05	83	9	-3	213	151	19:31	0	1:32
7/30/87	73.05	83	15	13	226	166	19:45	0	1:47
8/1/87	73.41	75	250	332	558	416	10:55	1	7:57
8/2/87	73.10	83	135	17	575	551	10:54	2	7:56
8/3/87	73.05	81	122	128	703	673	17:44	3	14:46
8/5/87	73.00	72	63	151	854	736	6:58	5	4:00
8/7/87	74.17	68	7	108	962	743	7:49	7	4:51
8/9/87	73.05	75	169	23	985	912	9:39	9	6:41
8/13/87	73.66	72	69	126	1111	981	10:08	13	7:09
8/17/87	73.38	71	170	153	1264	1151	7:30	17	4:31
8/21/87	74.02	72	12	33	1297	1163	9:40	21	6:42
8/26/87	73.51	73	124	77	1374	1287	18:10	26	15:12
8/31/87	73.61	73	50	51	1425	1337	8:54	31	5:56
9/5/87	73.91	74	59	60	1485	1396	23:11	36	9:43
9/11/87	73.51	75	154	109	1594	1550	11:33	41	22:04
9/18/87	72.85	74	39	12	1606	1589	11:30	48	22:01
9/27/87	74.02	75	2	51	1657	1591	13:09	57	23:41
10/6/87	72.67	74	31	-30	1627	1622	23:39	68	1:11
10/23/87	74.17	74	51	124	1751	1673	16:37	84	18:09
11/4/87	73.03	71	132	93	1844	1805	17:46	96	10:18
11/5/87	74.42	70	10	92	1936	1815	22:00	97	14:32
11/15/87	74.52	69	8	22	1958	1823	20:28	107	13:00
Lost Gas (cc @ STP)				13					
Vol. Accumulated (cc		@ STP)		1959					
Residual Gas (cc @		STP)		1241					
Methane content (Cubic			Feet/Ton of Coal)	66					

Table 2: Pittsburgh Desorption Data

PITTSBURGH

	ID No. 6D158811		*Weight of*	*Core gms*	*1648*				
Date	Atm. pressure cm Hg	Temp. Deg. F	Volume Measured cc	Volume Corrected cc @ stp	Volume Accumulated cc @ stp	Volume Before STP	Time	Elapsed Time Days	Hr:Mn
7/28/87	73.20	81	139	124	124	139	13:07	0	0:16
7/28/87	73.18	82	50	32	156	189	13:22	0	0:31
7/28/87	73.18	81	47	53	209	236	13:36	0	0:45
7/28/87	73.15	82	44	27	236	280	13:52	0	1:00
7/28/87	73.15	82	43	38	274	323	14:07	0	1:15
7/28/87	73.15	82	51	45	319	374	14:22	0	1:31
7/28/87	73.13	83	36	20	339	410	14:37	0	1:46
7/28/87	73.13	84	25	11	350	435	14:52	0	2:00
7/29/87	73.46	69	388	536	886	823	8:05	0	19:14
7/30/87	73.41	78	495	350	1236	1318	10:15	1	21:24
7/31/87	73.51	76	231	237	1473	1549	9:35	2	20:43
8/1/87	73.41	75	211	197	1670	1760	11:14	3	13:22
8/2/87	73.10	78	179	113	1783	1939	9:28	4	11:37
8/3/87	73.05	81	228	168	1951	2167	17:58	5	20:07
8/5/87	73.00	72	147	228	2179	2314	7:19	7	9:27
8/7/87	74.17	69	73	159	2338	2387	7:18	9	9:26
8/9/87	73.05	76	258	103	2441	2645	9:59	11	12:07
8/13/87	73.66	72	199	256	2697	2844	10:29	15	12:37
8/17/87	73.36	71	297	268	2965	3141	7:52	19	10:00
8/21/87	73.96	72	118	130	3095	3259	9:59	23	12:08
8/26/87	73.51	73	220	168	3263	3479	18:32	28	20:41
8/31/87	73.61	73	167	159	3422	3646	11:05	33	13:14
9/5/87	73.91	74	271	255	3677	3917	23:33	38	15:12
9/11/87	73.51	75	313	254	3930	6230	11:05	44	2:43
9/17/87	73.20	74	164	145	4075	4394	6:45	49	22:24
Lost Gas (cc @ STP)				62					
Vol. Accumulated (cc		@ STP)		4075					
Residual Gas (cc @		STP)		Not Analyzed					
Methane content (Cubic Feet/Ton of Coal)				80					

Table 3: Sewickley Desorption Data

SEWICKLEY

ID No. 6D1588291 Weight of Core gms 1527

7/27/87 Date	Atm. pressure cm Hg	Temp. Deg. F	Volume Measured cc	Volume Corrected cc @ stp	Volume Accumulated cc @ stp	Volume Before STP	17:00 Time	Elapsed Time Days	Hr:Mn
7/27/87	72.95	83	121	107	107	121	17:15	0	0:15
7/27/87	72.95	81	60	75	182	181	17:31	0	0:31
7/27/87	72.95	81	78	69	251	259	17:46	0	0:46
7/27/87	72.95	81	73	65	316	332	18:00	0	1:00
7/27/87	72.95	80	58	63	379	390	18:15	0	1:15
7/27/87	72.95	80	58	52	431	448	18:31	0	1:31
7/27/87	72.95	80	30	27	458	478	18:46	0	1:46
7/27/87	72.95	79	12	23	481	490	19:00	0	2:00
7/28/87	73.36	63	106	289	770	596	6:49	1	13:49
7/29/87	73.46	69	346	264	1034	942	8:18	2	15:18
7/30/87	73.41	76	321	215	1249	1263	9:24	3	16:24
7/31/87	73.51	76	153	144	1393	1416	9:30	4	16:30
8/1/87	73.41	75	150	142	1535	1566	11:05	5	9:05
8/2/87	73.10	77	142	90	1625	1708	9:18	6	7:18
8/3/87	73.05	81	178	111	1736	1886	17:50	7	15:49
8/5/87	73.00	72	98	185	1921	1984	7:11	9	5:11
8/7/87	74.17	68	37	139	2060	2021	7:13	11	5:12
8/9/87	73.05	75	213	59	2119	2234	9:51	13	7:51
8/13/87	73.66	72	137	190	2309	2371	10:20	17	8:20
8/17/87	73.36	71	236	212	2521	2607	7:43	21	5:43
8/21/87	73.96	72	65	81	2602	2672	9:49	25	7:48
8/26/87	73.51	73	191	140	2742	2863	18:22	30	16:21
8/31/87	73.61	73	101	98	2840	2964	9:07	35	7:06
9/5/87	73.91	74	106	103	2943	3070	23:21	40	10:50
9/11/87	73.51	75	222	170	3113	3292	11:43	46	23:13
9/18/87	72.85	74	125	90	3203	3417	11:40	53	23:09
9/27/87	74.02	75	82	125	3328	3499	13:19	62	0:48
10/6/87	72.67	74	172	96	3424	3671	23:25	71	1:54
10/15/87	74.04	74	11	82	3506	3682	17:18	80	19:48
10/23/87	74.17	76	72	51	3557	3754	16:47	88	19:17
11/4/87	73.03	71	137	119	3676	3891	17:52	100	11:22
11/15/87	74.52	69	3	103	3779	3894	20:24	111	13:53
Lost Gas (cc @ STP)			74						
Vol. Accumulated (cc		@ STP)	3781						
Residual Gas (cc @		STP)	578						
Methane content (Cubic Feet/Ton of Coal)			97						

B. *Gateway Mine Analysis*

Production of methane from GOB areas has been a critical problem in conjunction with mining operations. Much effort has been spent by various researchers to attempt to understand the mechanisms, magnitude, control mechanisms and resource potential of methane production. Data collected by the USBM at the Gateway mine, which follows, was used in developing the GOB well Analytical Model.

1. USBM Gateway Testing

The U.S. Bureau of Mines[2] investigated the influence atmospheric pressure changes on methane gas migration from the Gateway mine through mine seals at the adjacent Lazarus mine site located in the Pittsburgh Coalbed. The mine gained access to a coal reserve through part of an abandoned mine (Gateway) and constructed nine seals to isolate the extensive old workings from the active mine area. Underground problems were experienced when atmospheric pressure fell, causing methane gas to migrate around the seals and into the active workings.

During mining operations, methane gas levels exceeded legal limits and coal production was halted until the ventilation system could be improved. When mining resumed with increased air flow, methane gas concentrations occasionally exceeded the legal limits and production had to be halted until the methane level fell within the mandated limit.

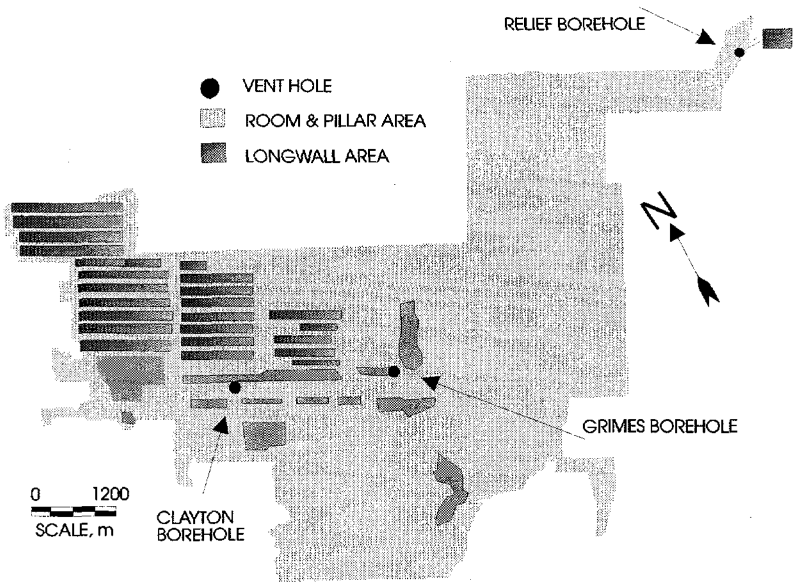
The USBM study was aimed at designing a pressure relief borehole located in the abandoned workings near the mine seals area so that the ventilation system could dilute the gas in the active workings. The amount of methane gas that migrated into the active mine workings was monitored, as well as seal pressure, during periods of low atmospheric pressure.

When the barometric pressure falls, the equilibrium pressure of the gob exceeds the pressure in the active mine. As a result, gas migrates from the gob through the seals into active mine workings where a mixture of gob gas and mine air can reach an explosive concentration (5 to 15% methane). Conversely, as barometric pressure increases, the volume of gas in the gob decreases. During these periods, inflows of oxygen-rich mine air into the gob occur, which can increase the potential for spontaneous combustion and the formation of explosive gas mixtures in the gob.

The Gateway mine has an abandoned area of approximately 36.2 Mm^2 (390 $mmft^2$) and the average coalbed thickness in the mine was approximately 1.83 m (6-ft). A large portion of abandoned workings was extracted by room-and-pillar mining with an estimated extraction percentage of about 50%. The mine was closed about four years earlier and water that accumulated in inaccessible areas reduced overall gob volume.

Once a gob is sealed, methane gas concentration rises rapidly until it approaches a steady state value. The methane gas concentration of the gob will fluctuate above and below this value with barometric pressure changes depending on the gas production. The methane gas concentration measured at the Clayton and Grimes boreholes (see Figure 12:) was 60%.

Figure 12: Gateway Mine Map



a) Prior to completion of pressure relief borehole

When the mine resumed production under the 90-Day Plan, the Clayton and Grimes boreholes located in the abandoned area were not yet enlarged. The USBM monitored methane gas flows and seal pressure during a 12-day period before a pressure relief borehole was drilled. Figure 13: shows the total methane gas inflow into the active mine during this period. Maximum inflow rate was 0.4 m^3/s (848 cfm) of methane.

Figure 13: Methane Emissions-Before Relief Well Drilled

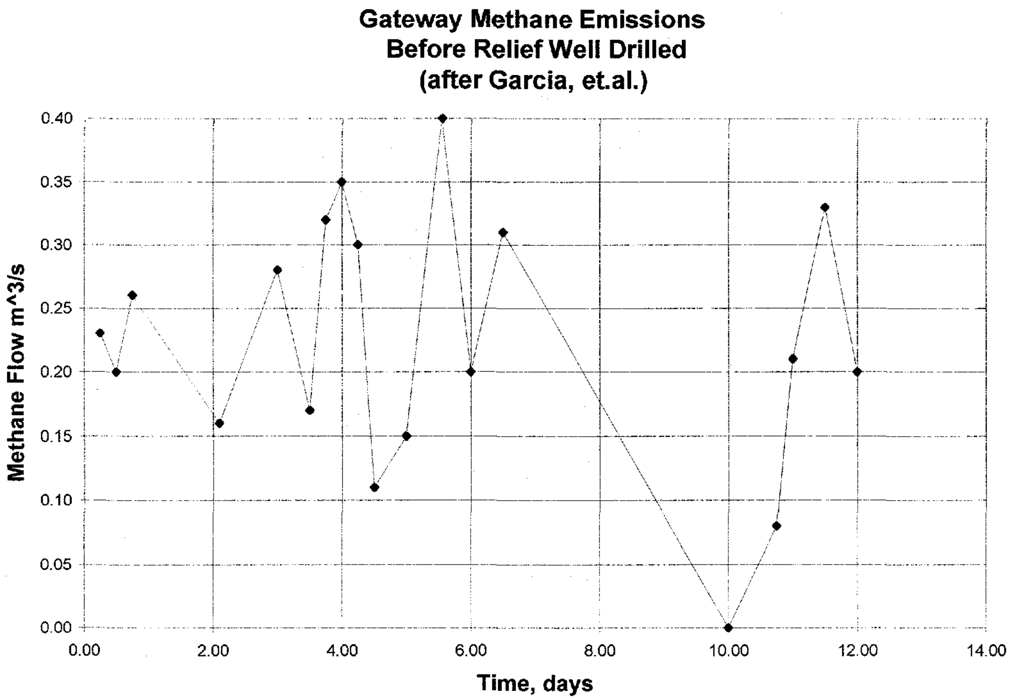
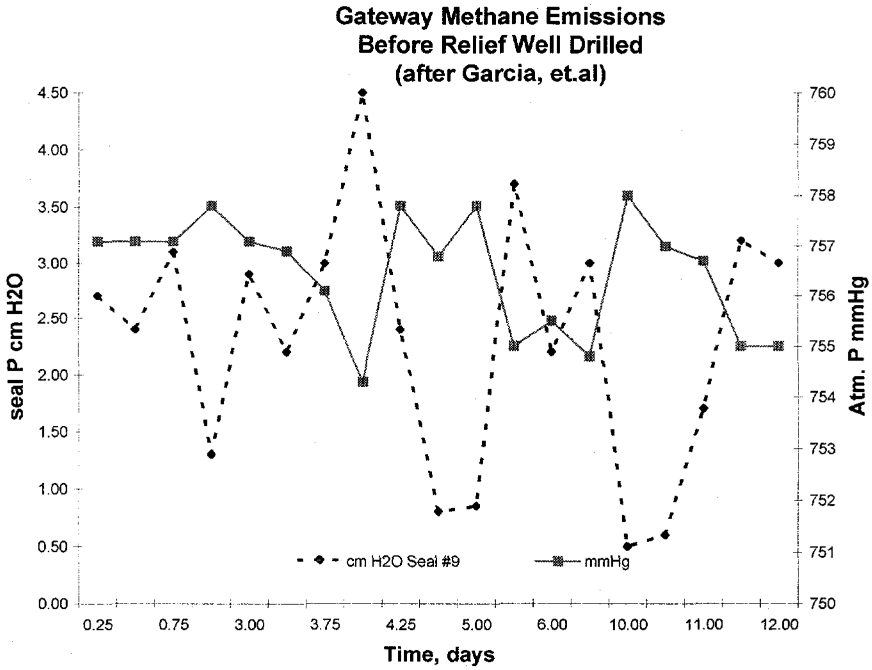


Figure 14: shows the variation of barometric pressure at the No. 9 seal during this period. The barometric pressure varied over a range of approximately 6.4 mm (0.24 in) Hg. Note that whenever the static pressure across the seal produces a negative reading, this indicates that the pressure of the mine air is higher than the equilibrium pressure in the abandoned area. Conversely a positive pressure across the seal suggests that the equilibrium pressure in the abandoned area is higher than the pressure of the mine air.

Figure 14: Atmospheric and Seal Pressure - Before Relief Well Drilled

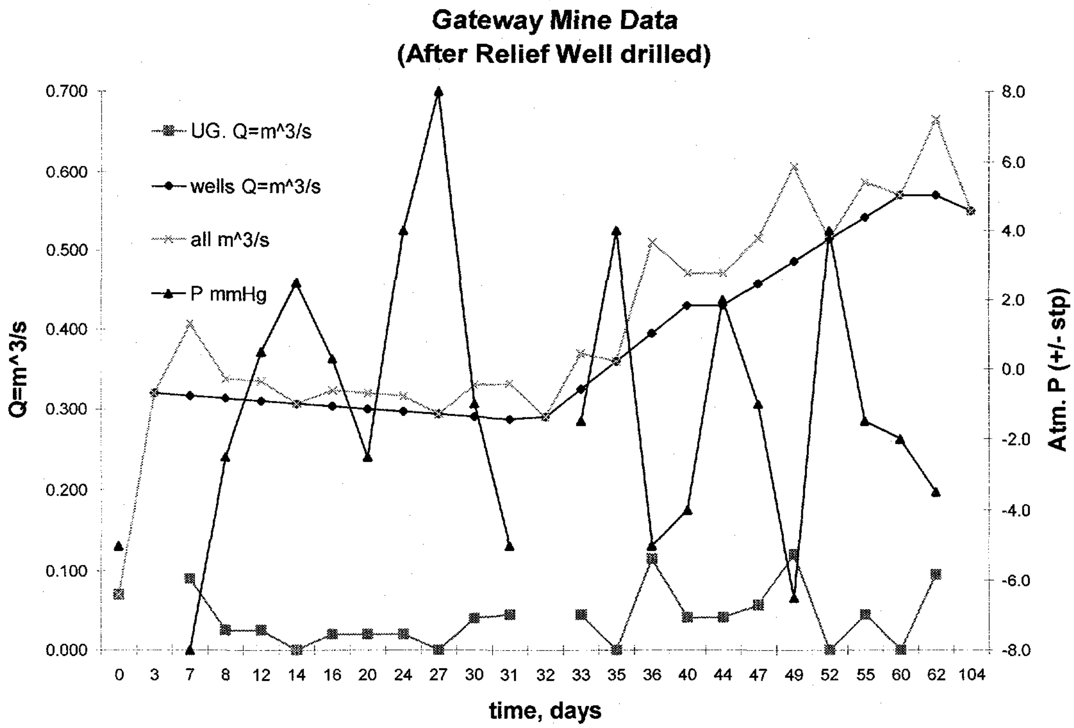


Inflows of mine air into the abandoned area occurred around day 10,as shown in Figure 13: . Also, a high barometric pressure and a negative seal pressure,as shown in Figure 14, air was flowing into the abandoned area and zero methane gas concentration was measured at the seals during this period. As shown in Figure 14: , a change in barometric pressure is followed by a rapid change in seal pressure, suggesting the abandoned area near the seals was responding rapidly to barometric pressure changes.

b) Mine conditions after the borehole was completed

Figure 15: shows how underground methane emissions from the sealed area and barometric pressure varied after drilling the pressure relief borehole and enlarging the Clayton and Grimes boreholes.

Figure 15: Gateway Mine Flow (m^3/s), Atm (+/-) gob P, vs. Time



During this period, the peak methane flow rate measured was 0.15 m^3/s (318 cfm) while barometric pressure varied over a range of 17.3 mm (0.68 in) Hg, as compared to a peak methane flow rate of 0.4 m^3/s (848 cfm) with a 6.4 mm (0.24 in) Hg change in barometric pressure before the borehole was drilled, as shown in Figure 13: . Thus the level of methane gas emissions into active mine workings were reduced by at least 2.7 times after the relief borehole was completed and the enlarged Clayton and Grimes boreholes were functional.

Coal production was no longer impeded by gas problems caused by atmospheric pressure changes. Gas emissions from the surface boreholes were not monitored until after the pressure relief borehole was drilled and after the Clayton and Grimes boreholes were enlarged and check valves were installed. A correction factor was applied to vane anemometer measurements made at the Clayton and Grimes borehole duct outlets to calculate the gas flow rates as directed by Garcia and Cervik (1987). A pitot tube was used to determine gas velocity in the pressure relief borehole. Hand-held methanometer readings and bottle samples were used to determine the concentration of methane gas in the flow stream. Thus, methane flow rates could be calculated.

Figure 16: compares methane gas flow of the vent boreholes to the mine emissions over 140 days. Following the drilling of the pressure relief borehole, the enlargement of the Clayton and Grimes boreholes and the installation of check valves, the boreholes produced approximately seven times the volume of methane gas emitted into the mine workings. Obviously, these changes had a significant effect in reducing methane gas emissions into the mine workings.

Figure 16: Gateway Methane Flows - MCFD vs. Time

Borehole Methane Flows & Mine Emissions

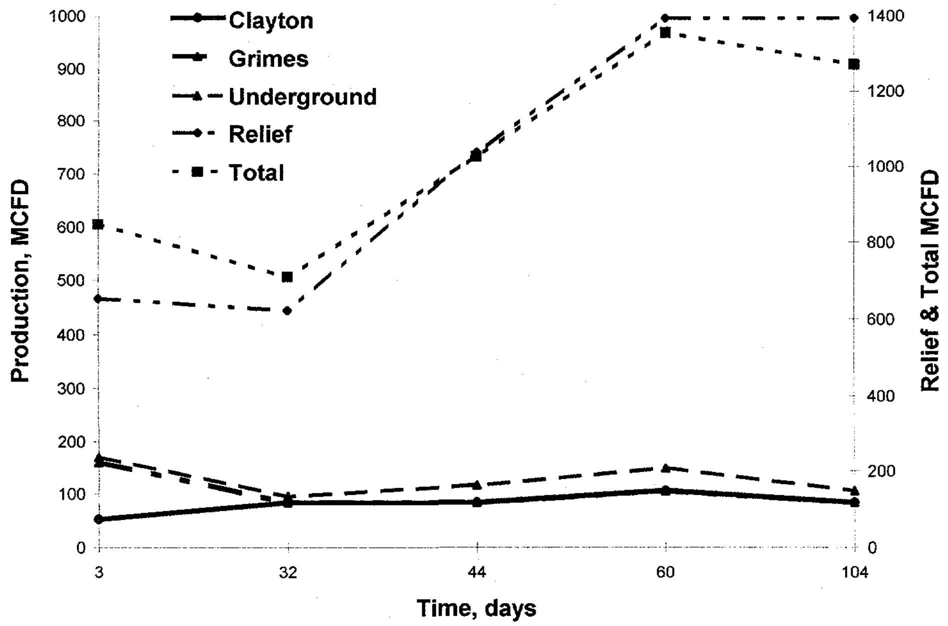


Table 4: shows an analysis of gas samples collected from the boreholes and immediately behind No. 9 seal on day 62. The gas flow into the mine from the abandoned area was approximately 0.09 m^3/s (190 cfm) on day 62 as shown in Figure 16: . The sealed methane gas concentration appears to have reached a steady state value as the atmospheric pressure changes did not affect the concentration of gas flowing from Clayton and Grimes boreholes over a 140-day period. Inflows of oxygen-rich mine air into the abandoned area during prolonged periods of high pressure only slightly reduce methane gas concentration levels at the relief borehole and the No. 9 seal.

Table 4: Gas Analysis

Gas Analysis	Clayton	Grimes	Underground	Relief
nitrogen	28.75%	28.67%	47.69%	38.99%
oxygen	0.12%	0.12%	0.15%	0.26%
methane	62.19%	62.18%	43.25%	51.76%
carbon dioxide	7.89%	7.97%	7.58%	8.25%
other	1.05%	1.06%	1.33%	0.78%
Total	100%	100%	100%	100%
Ratio O_2/N_2	0.004	0.004	0.003	0.007

Air issuing into an abandoned area will diffuse with gob gas according to Graham's Law of Diffusion and form an air-methane mixture. Typically, the oxygen/nitrogen (O_2/N_2) percent ratio, is equal to about 0.27 for normal air. This ratio should also be observed in the abandoned area unless processes such as oxidation or combustion of organic compounds occur. The ratio calculated from a gas sample collected at the Grimes borehole was approximately 0.004, a notably large discrepancy from the expected ratio. However, if a ratio of oxygen plus carbon dioxide to nitrogen $(O_2 + CO_2)/N_2$ is used, it is comparable to a typical O_2/N_2 ratio for this sample which indicates that a conversion of oxygen to carbon dioxide occurred. Consequently, a low-temperature oxidation process such as the slow oxidation of coal or decay of mine timbers could be occurring in the abandoned area.

Once a combustible gas or vapor is in an atmosphere where the oxygen level is reduced below a certain percentage, the gas or vapor will not burn or explode. At atmospheric conditions, methane gas becomes inert at an approximately 12% (by volume of oxygen) in any methane mixture, as determined by Jones, Kennedy, and Spolan (1949). The oxygen content of the gob gases, determined from samples collected at all study locations, were far below that level. A possible exception to this would be the immediate area on the abandoned side of a seal right after the inflow of air from the active mine. It is believed that subsequent inflow and outflow of gas during changes in atmospheric pressure cannot significantly alter these conditions. Consequently, since the vast majority of the gob is inert, an explosion or fire would be less likely to occur in the abandoned area under these conditions.

c) Methane Calculations

The data collected by the USBM was used to develop an analytical model to calculate methane flow. From the principals developed by Foster and Miller[1] and Darcy horizontal flow calculation, a P(f) function was calculated using seal, barometric, and average pressures for the mine at depth.

$P(f) = (P_{(gob)} - P_v)/P_{avg}$
$P_{(gob)}$ = gob pressure
P_v = atmospheric pressure
P_{avg} = average pressure at depth

From Darcy's law and work by Foster and Miller above, the plot of this data should result in a straight line. The following Figures Nos. 17, 18 and 19 are plots of the data obtained by the USBM before the relief well was drilled showing the actual MCFD and calculated values, along with the barometric and seal pressures. As noted, as the seal pressure increases, the calculated and measured methane flow rates increase accordingly.

Figure 17: Gateway Methane Flow (MCFD), Seal Pressure, vs. P(f)

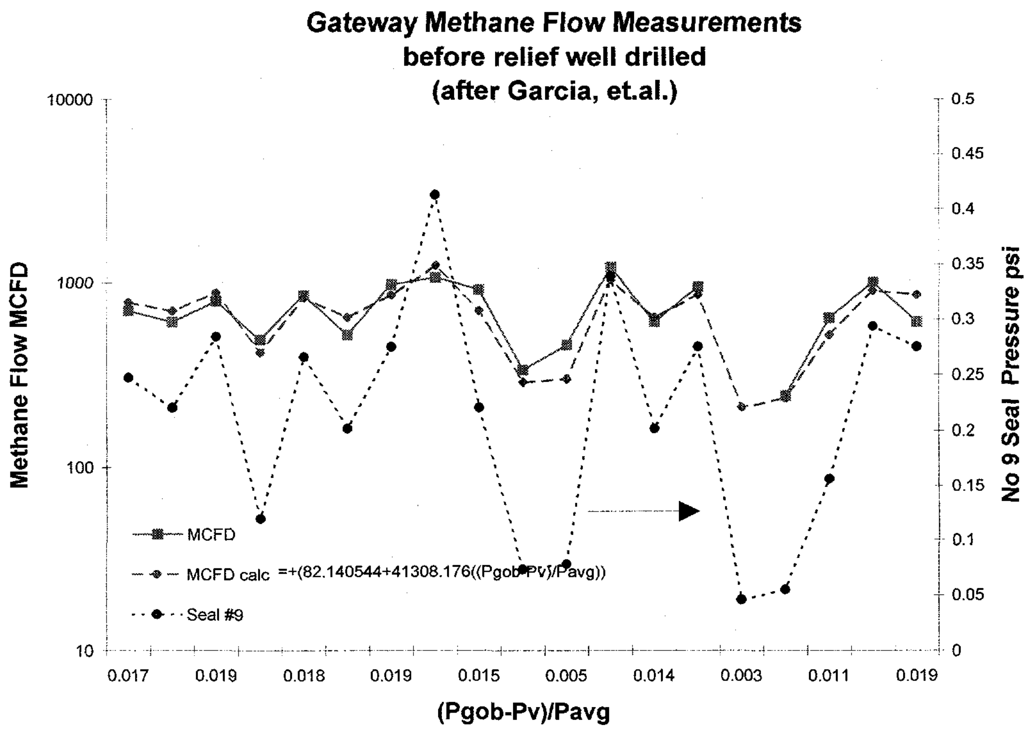


Figure 18: Gateway Methane Flow, Barometric P, vs. P(f)

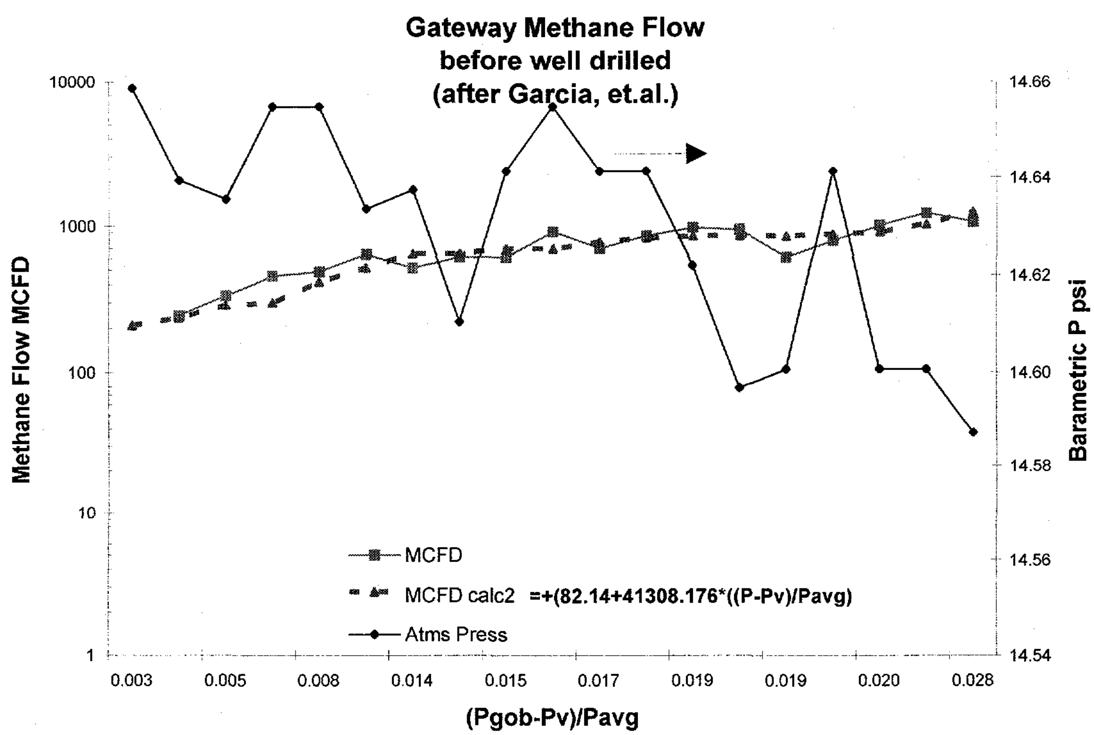
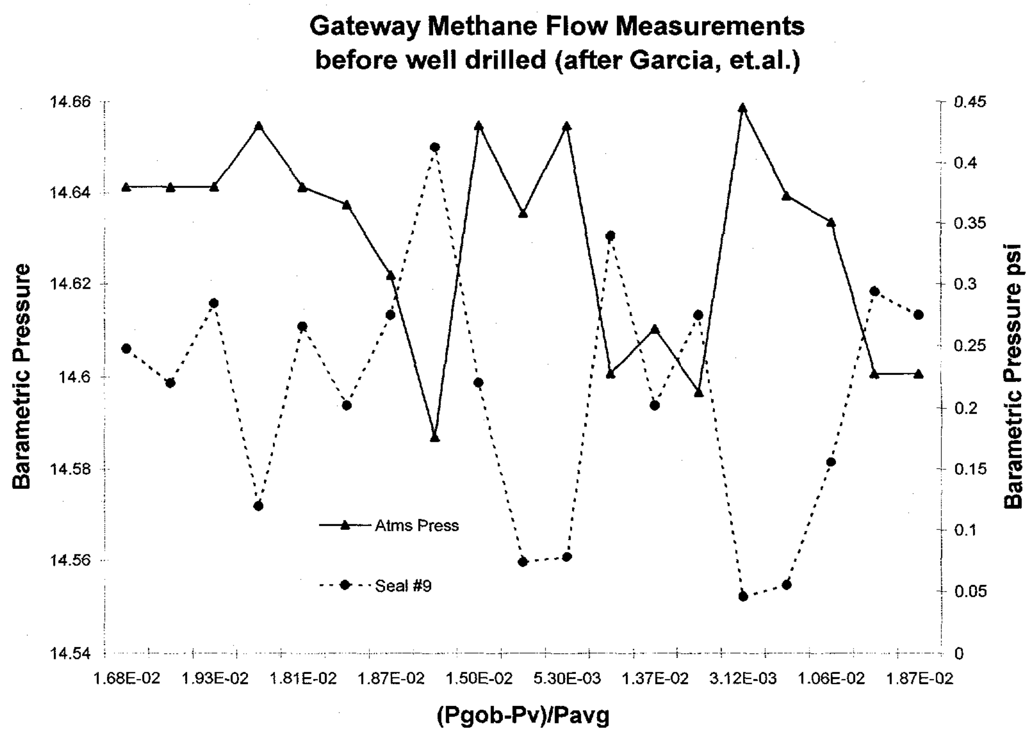


Figure 19: Gateway Mine Barometric P, Seal P, vs. P(f)



The total flow from the Gateway mine is the sum of the vertical ventilation holes plus methane leaking though the seals. The methane concentration within the seals is determined by the pressure differential of the P_{gob} (+/-) atmospheric pressure. Figure No. 20 shows the total methane flow from the Gateway mine after the relief well was drilled. Figure No. 21 shows the gas flow relationship from both wells and underground as a function of atmospheric and gob pressure. As atmospheric pressure increases, total flow decreases. The following Figure No. 22 shows the relationship between the gob(calc) and measured and calculated flow.

Figure 20: Gateway Mine Methane Flow (m^3/s) vs. Time after Relief Well

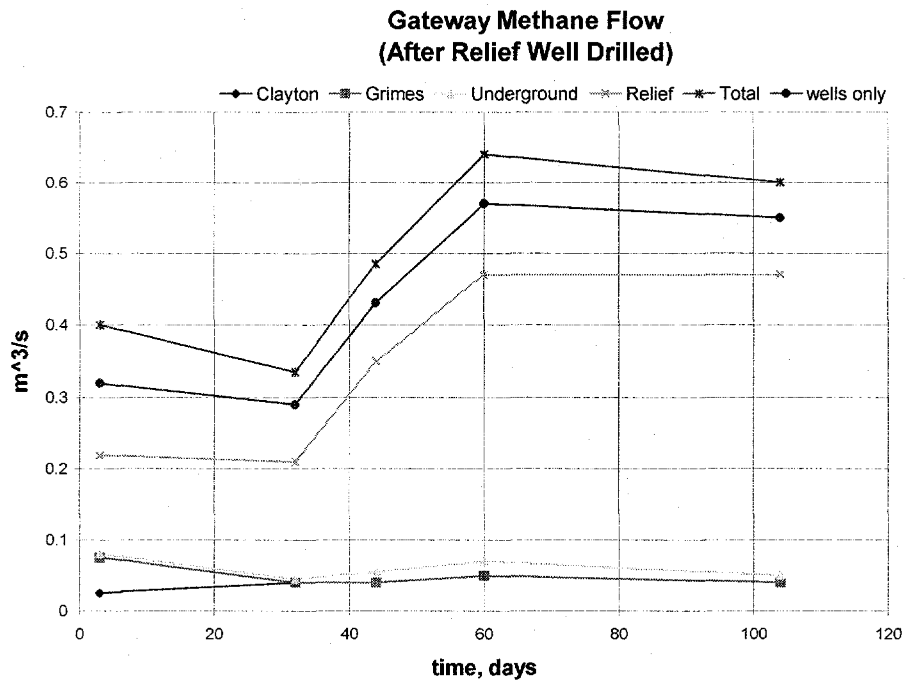


Figure 21: Gateway Mine Total Methane Flows (after Relief well) vs. GOB P (+/-) Atm. -mmHg

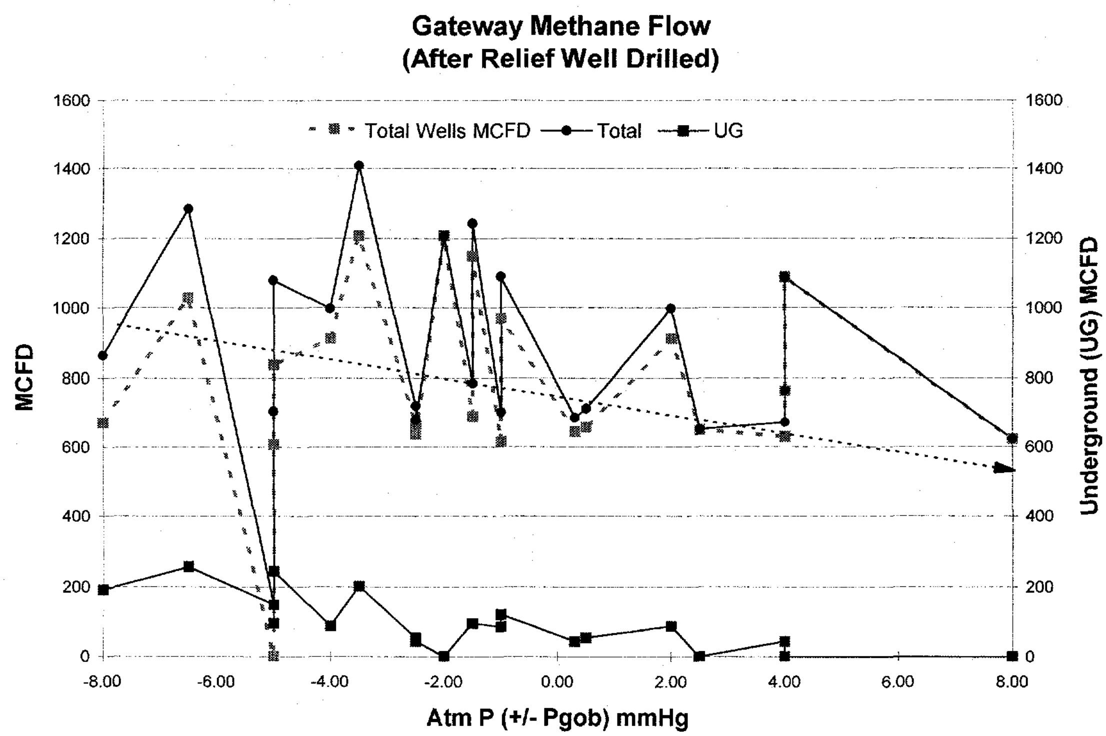
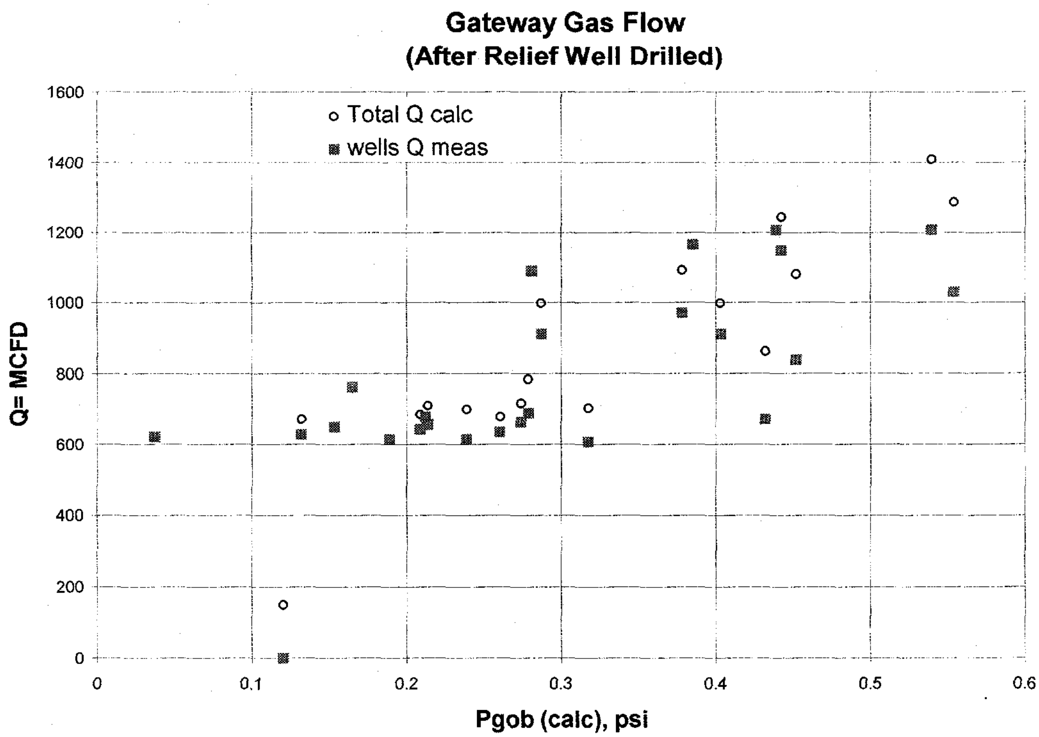


Figure 22: Gateway Flow Total (measured), (calculated) vs. GOB P



2. GOB Well Performance

Layne[2], et.al, performed one of the earliest in-depth assessment of the dynamics of coalbed methane generation and drainage associated with longwall mining. In this evaluation, SUGARWAT (a two-phase reservoir simulator) was used to model actual GOB well performance data.

Observations and conclusion were that:

- Pipeline quality gas production from the highly fractured methane-bearing strata above longwall coal mine panels is predicted to be many times that of the gas-in-place estimate for the mineable coalbed.
- This production is thought to come from relatively shallow gas-bearing coals, organic shales, and sandstones.
- In the mining process, permeability of shallower strata is increased significantly because of the fractured zone generated during longwall mining activity and, hence, gas could be produced at volumes many times that of an average conventional gas well.
- Production data from actual wells above a longwall panel were history matched to characterize flow mechanisms and reservoir properties.
- Results indicate that cumulative gas production can be increased by placing wells farther apart than 1,000 ft (304.8 m).
- During longwall mining, several rock strata above the mine roof fracture and collapse into the mine cavity.
- The zone in which the overlying rock breaks and fractures is referred to as the "gob" or the "fracture zone".
- Although the exact shape of the cave zone is not known, it is generally believed to have a dome shape.
- However, the shape of the cave zone depends on many factors, such as geologic features, overburden height, the amount of in situ stresses, and rock properties.

- During mining, the strata's permeability to gas flow increases significantly, causing more gas release from upper-strata coal seams and other gas bearing formations, such as organic shales and porous sands located in the fractured gob area.
- The productivity of methane extraction wells depends on their designed location in the gob area and the spacing between the wells.
- The history matching was based on the actual and projected gas production and was extrapolated by an exponential and hyperbolic curve fitting routine that was used to extrapolate the data over a 10-year production life. (As shown below.)

Figure 23: Expected GOB Production (after Layne), vs. Time - hyperbolic

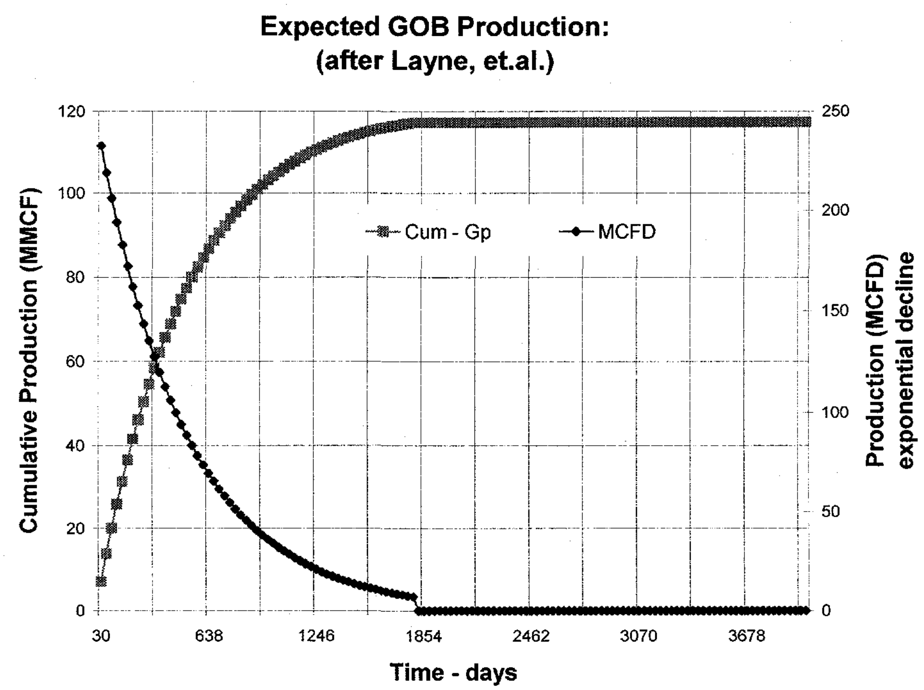
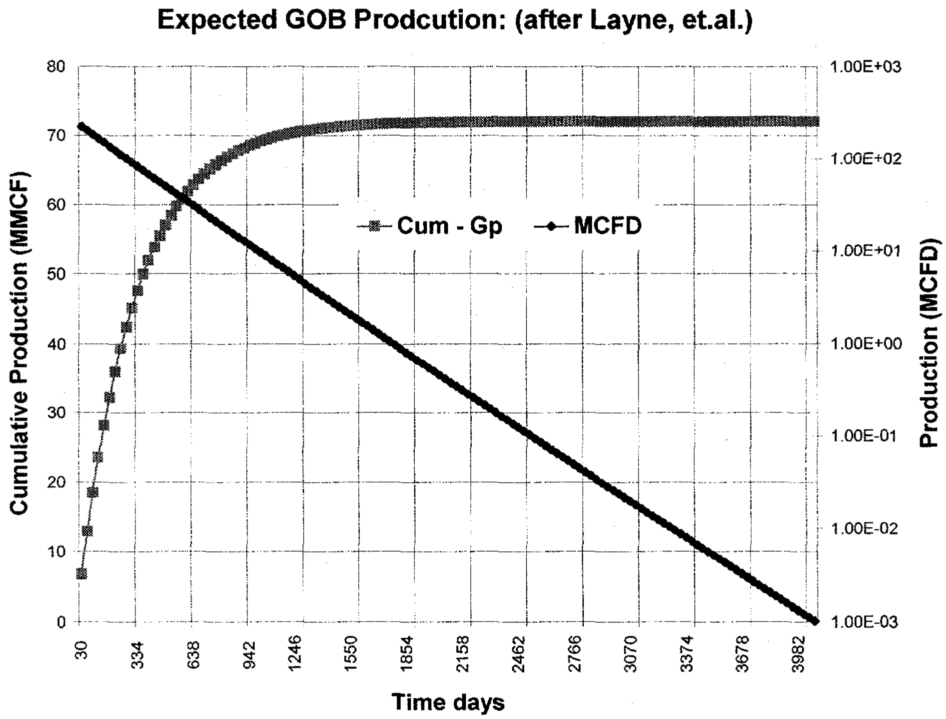


Figure 24: Expected GOB Production (after Layne), vs. Time - exponential



The SUGARWAT reservoir model was used to determine history-matching parameters by simulating production from gob wells in the panel.

- The SUGARWAT model is a two-dimensional, two-phase, reservoir model that simulates the production of gas and water from a conventional reservoir.
- This reservoir is modeled as a continuous natural fracture system filled with discontinuous matrix blocks.
- The matrix is represented as discrete "blocks" or "elements," and exhibits a high porosity and low permeability.
- These are the major gas storage locations and contribute very little flow to the reservoir. The natural fracture system provides little storage and acts as the major flow network in the reservoir.
- The SUGARWAT gas flow mechanism is based on the matrix/fracture dual porosity concept.
- The matrix is the high-porosity, high-potential system, and is the source of gas flow in the surrounding low-porosity fractures.
- The fracture flow in SUGARWAT was developed by combining the continuity equation, Darcy's law, and a density pressure-dependent, shrinkage factor relationship.
- The flow equation was derived by developing the generalized mass balance or continuity equation over a representative element in a rectangular system.
- The fundamental conservation relationship was then written in terms of the flux rate of fluid being conserved, the fluid concentration, and the input rate.
- An equation for each fluid phase was written with a relation of the flux and concentration through a common dependent variable.
- Since the reservoir was fractured, flow from the rock matrix was accounted for by a pressure-difference source term added to the fracture flow equation.

- The fluid flow from the rock matrix was described with the matrix/fracture flow equations. These equations were derived from the definition of pseudo-steady-state flow out of a matrix element.
- This was expressed in terms of the matrix gas concentration, porosity, and change of average matrix pressure with respect to time.
- Generally, methane desorbtion is simulated with a kinetic Fickian Diffusion model. However, SUGARWAT is based on the pseudo-steady-state desorbtion concept, in which matrix porosity and permeability are used to describe the gas desorbtion.
- Matrix permeability, which can represent the diffusion flow from the coal matrix walls, can be calculated using relationship between Darcy's law, Fick's law, the equation of state and the concentration density relationship.

Analysis of Cave Zone

- The tensile zone extends to a height of about 339 ft (103.3 m) (67 times the seam thickness) above the mine roof. It can also be noted that two disjointed smaller zones are present above this height of about 815 ft (248.4 m) above the mine roof.
- The gas-bearing strata located within the fracture zone are believed to produce gob gas.

C. *Analytical Gob Well Model*

Individual GOB well production can be calculated by a variety of methods. The method used here is the average pressure and temperature method as presented by Cullender and Smith.

Table 5: Equation Summary - Reynolds Number, Pwf

Average Temperature & Pressure Method:

$$P_{wf}^2 = P_{tf}^2 * Exp(S) + (25 * sp.gr. * q_{(sc)}^2 * T_{avg} * f * z_{avg} * D * (exp(S) - 1))/S * d^5)$$

$$S = .0375 * gas\ gr. * MD / (T_{avg} * z)$$

Jain Solution:

$$f = (1.14 - 2*Log(e/D + 21.25/N(Re)^{\wedge}0.9))^{\wedge}-2$$

Reynolds Number:

$$N(Re) = (20011 * gas\ gr. * q_{(sc)}) / (\mu * d)$$

Where:

P_{wf} = well flowing pressure

P_{tf} = flowing tubing pressure (atmospheric pressure)

Table 6: Model Data Input Summary

gas gr.	**0.738**	
μ= gas viscosity cp	**0.0152**	
$q_{(sc)}$ = rate MMscfd		
d= pipe dia. in.	**5.5**	
z= comp factor	**0.998**	
T_{avg} = avg temp deg R	340	
MD= well depth ft.	500	
d= in. pipe dia.	5.5"	8"
e/D= relative roughness	0.001	0.0009

A plot of the rate pressure relationship derived from these calculations is shown on the following Figure No. 25. In this generic example, barometric pressure (P_{tf}) was reduced from the initial $P_{ft(i)}$ in small pressure increments. The reduction in barometric pressure in shown in mmHg on the second Y-axis. The difference of (P_{wf} - P_{tf}) is shown in inches (Wg.). The resulting rate (cfm) is calculated as a result of the reduction in barometric pressure. Very high rates are possible with very small changes of barometric pressure.

Figure No. 26 shows the relationship to the P(f). P(gob) in this example is Pwf, Pv is barometric pressure. The resulting rate is shown in cfm. Very small decreases in barometric pressure can support very large flow rates. Figure No. 27 shows rate (MMCFD) vs change in barometric pressure (cmHg).

The average pressure (Pavg) was calculated by the following equation , where:
P(avg) = mmHg
EL = elevation (ft)

Table 7: Atmospheric Equation

P(avg)=+(a+c*EL+e*EL^2+g*EL^3+j*EL^4)/(1+b*EL+d*EL^2+f*EL^3+h*EL^4+j*EL^5)

a= 7.60E+02	*b= -1.21E-05*	*c= -8.33E-03*	
d= 2.34E-09	*e= 3.35E-08*	*f= -3.17E-14*	
h= 4.60E-19	*g= -5.83E-14*	*i= 3.73E-20*	*j= -1.41E-24*

Figure 25: Model Calculated GOB Well Performance - Rate, GOB P, vs. Barometric P (mmHg)

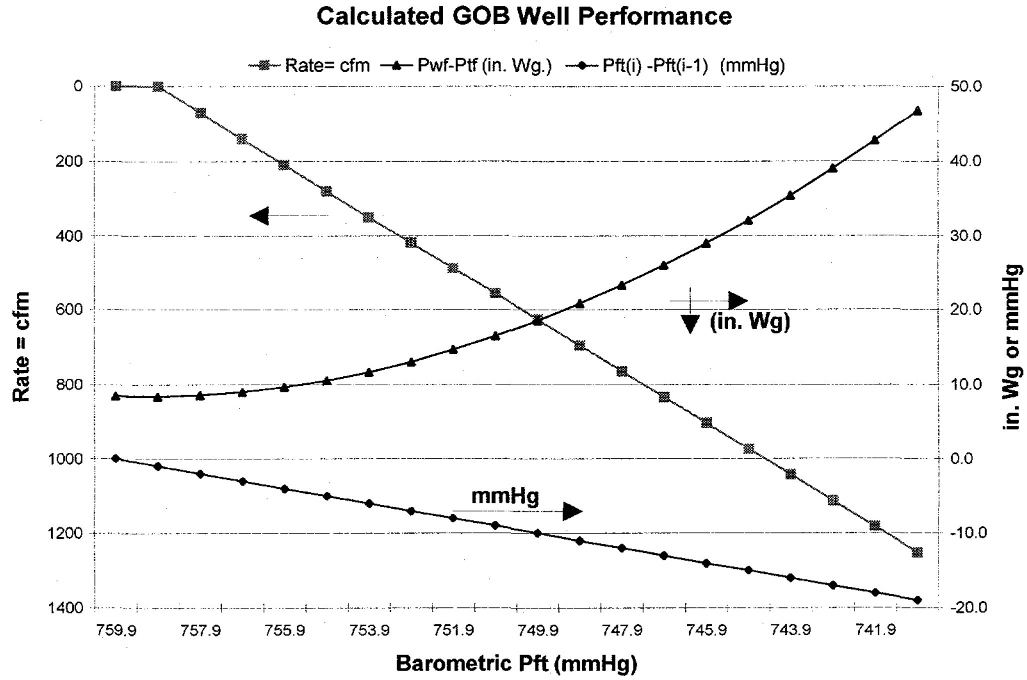


Figure 26: Calculated GOB Well Performance - Rate, Barometric P change (mmHg) vs. P(f)

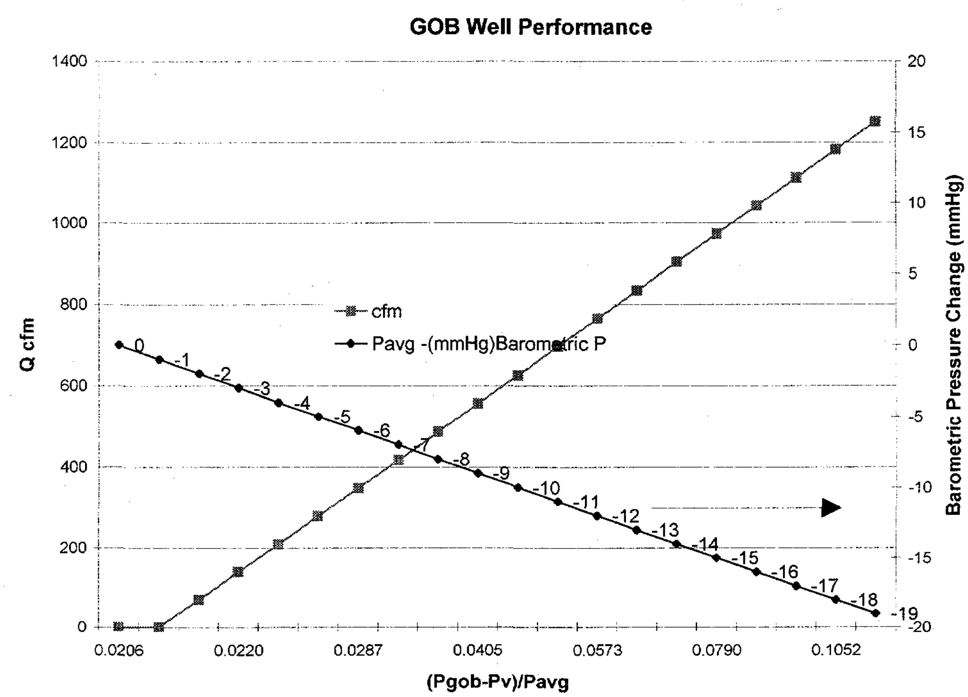


Figure 27: Calculated Rate, P(f), vs. Barometric P change (cmHg)

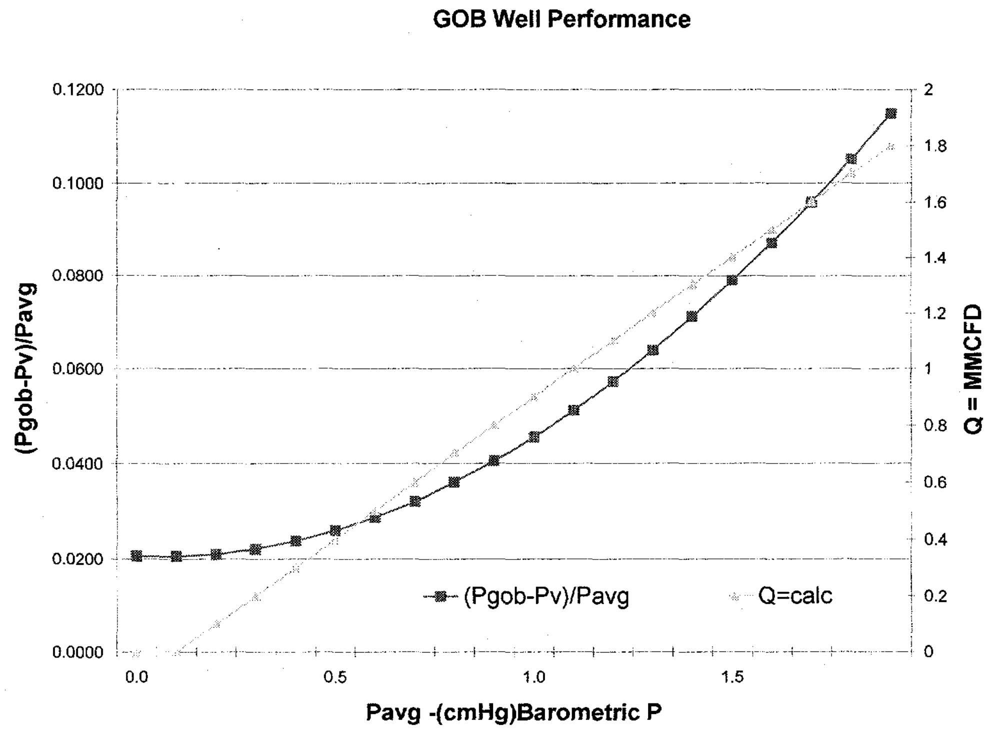
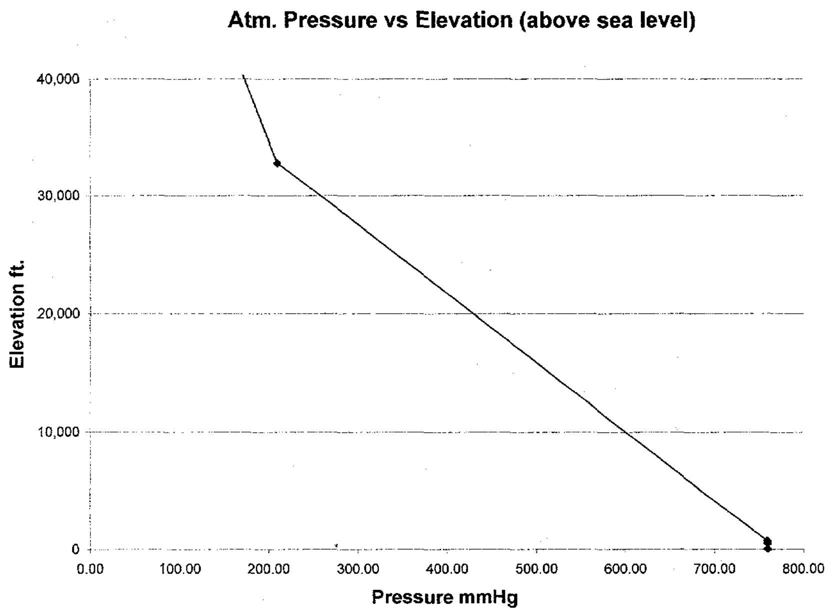


Figure 28: *Atmospheric P vs. Elevation (above sea level)*



D. Gateway GOB Prediction

Forcast of production and reserve sensitivity analyse were performed. The following graphs and tables summarize the sensitivity analysis. The following Table No. 8 summarizes the gas in place utilizing data presented by Layne[2] and based on the desorption data provided by CNG. Total area of the mine is 8953 acres. Total gas in place is approximately 40 BCF.

Table 8: GIP Gateway Mine

Depth - ft.		h=	cu.ft./t	GIP - BCF
100	Waynesburg	4	90	5.96
225	Uniontown	2.5	100	4.14
375	Sewickley	5	120	9.94
425	Redstone	5	125	10.35
500	Pittsburgh	3	200	9.94
	Total	19.5	125	40.33

Depth - ft.		h=	cu.ft./t	GIP - BCF
100	Waynesburg	4.5	60	4.02
225	Uniontown	6	67	5.96
375	Sewickley	6	80	7.16
425	Redstone	6	83	7.45
500	Pittsburgh	7	133	14.17
	Total	30	83	38.77
		avg=	104	39.55

The following Figure No. 29 shows the range of GIP estimates based on gas content and total coal seam thicknesses for the entire Gateway mine acreage. The range is expected gas in place estimates range from 119 to 40 BCF. Figure No. 30 shows anticipated reserves (30 yr.) as a function of change in barometric pressure changes of 2 - 8" water gauge and number of wells drilled for 100 and 200 scf/ton.

Key parameters evaluated indicate that the number of wells drilled versus the desorption rate is senstive to gas in place estimates. That is, the more wells drilled will not necessarily proportionately increase ultimate reserves. Figure No. 31 illustrates an example in which 20 wells were drilled in 36 feet of coal with a large pressure differential (20" Wg.). As show the annual production declines at a more rapid rate than to a similar case with a pressure differential of (8" Wg.). This factor was considered in the economic optimization analysis.

Figure 29: GIP vs. Thickness and Gas Content

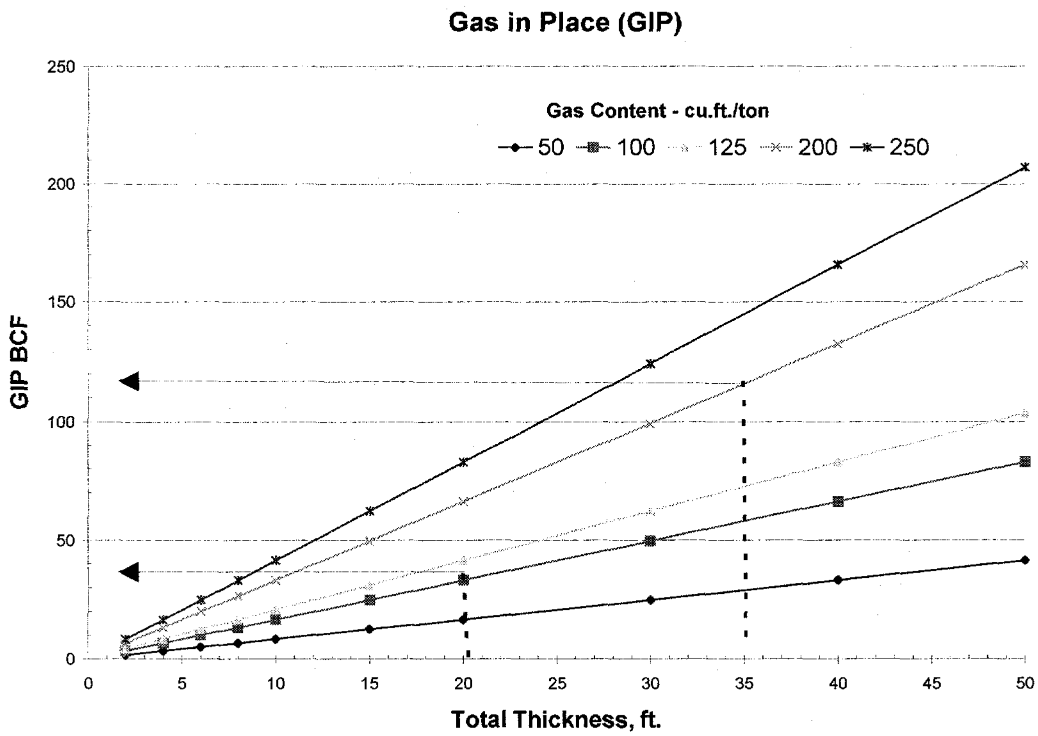


Figure 30: Reserves vs. P(gob-atm)

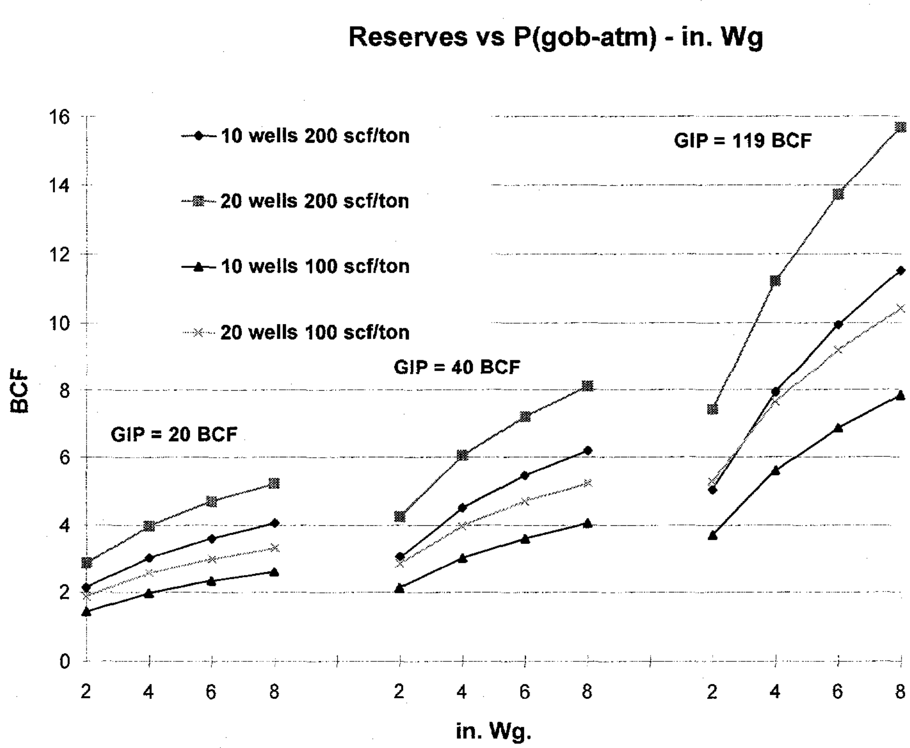


Figure 31: Annual Production Forecast

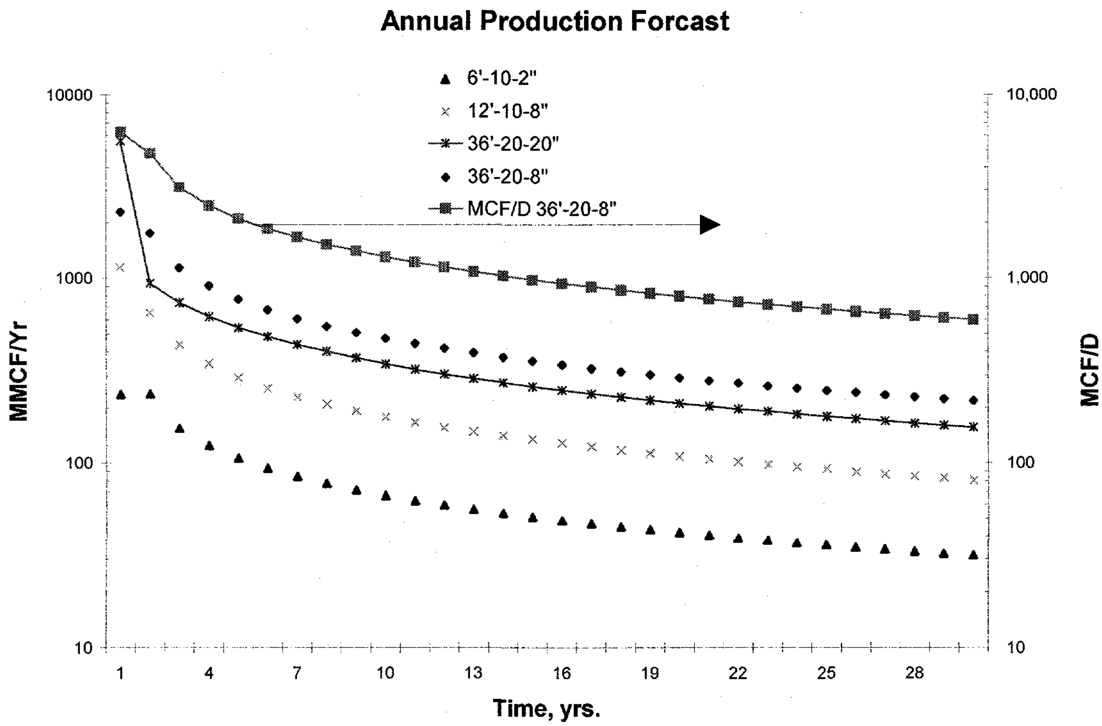
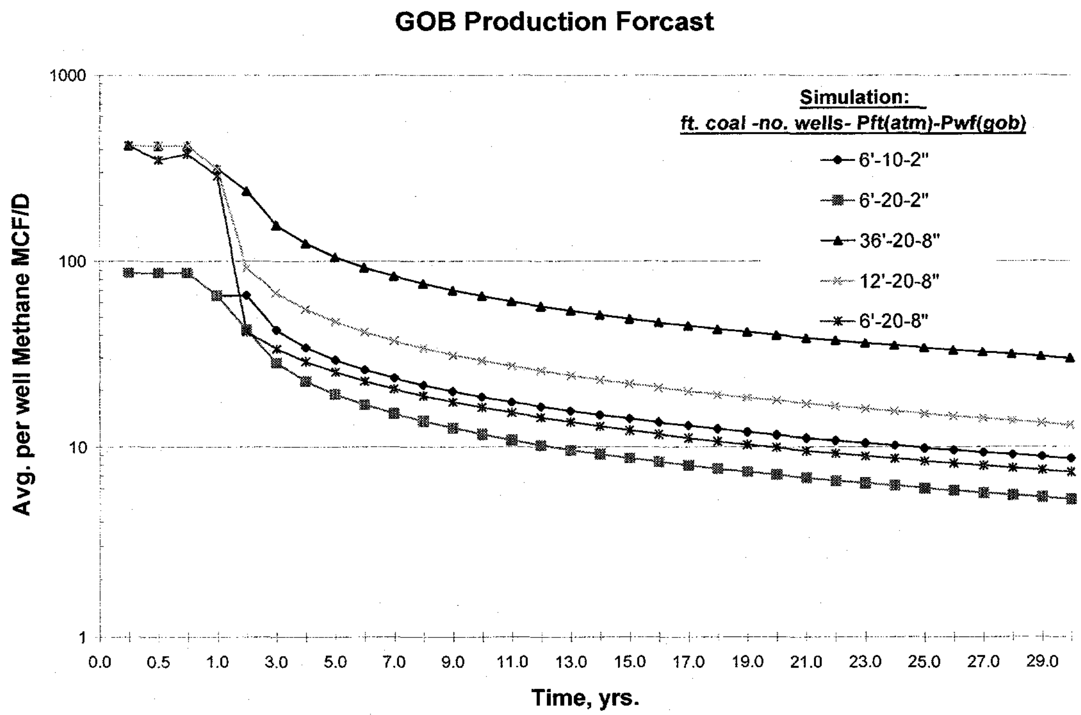


Figure 32: GOB Well Production Forecast

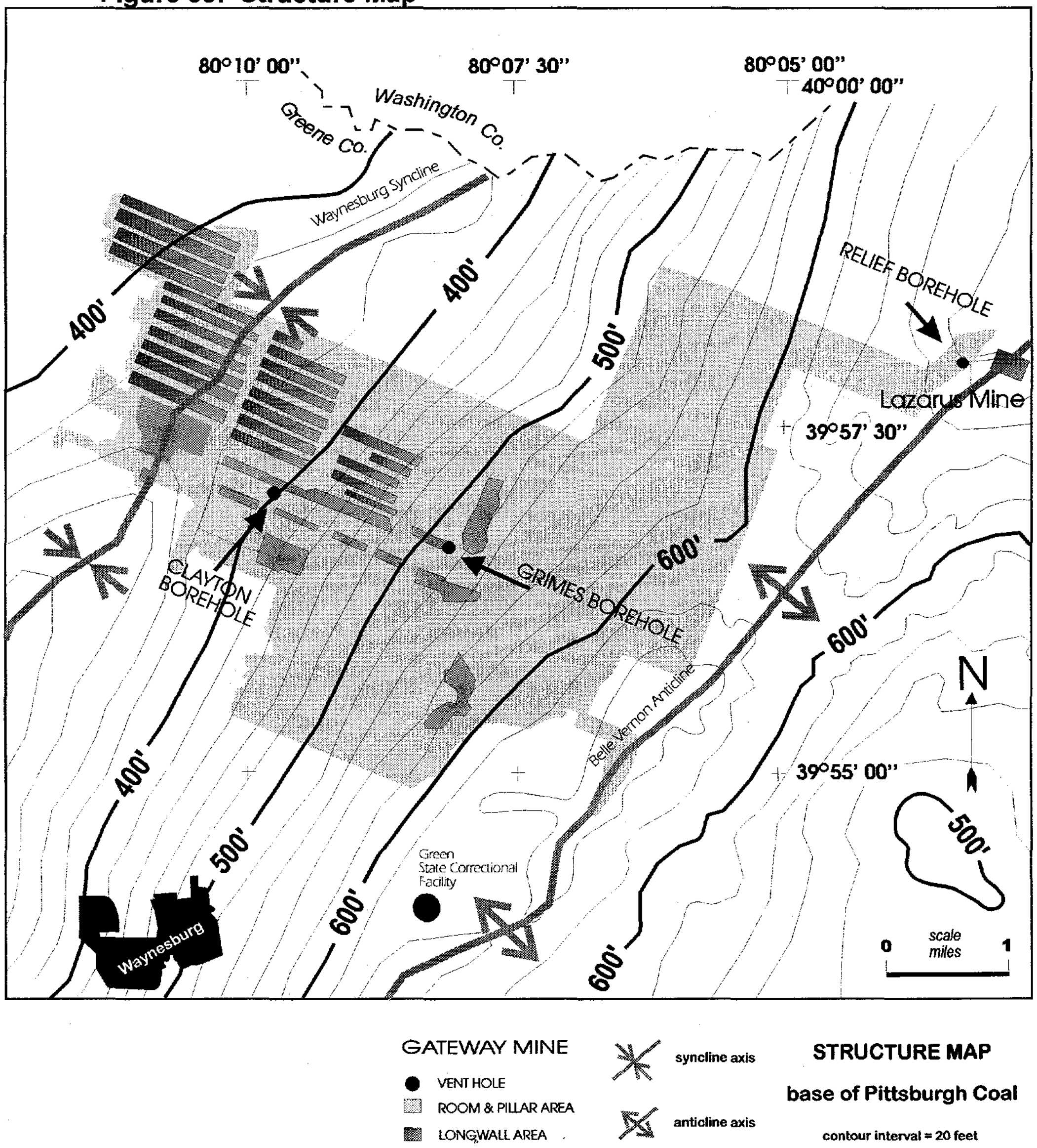


III. Geologic Model

A. GATEWAY MINE

The abandoned Gateway mine (Pittsburgh coal seam) is located in Greene County northeast of the town of Waynesburg, as shown in the index map (Figure 1) at the beginning of this report. As seen from this index map, most of the unmined Pittsburgh coal reserves lie to the west of the Gateway Mine, where Consolidation Coal (CONSOL) is the primary acreage holder. Greene County has more unmined coal than any other county in Pennsylvania and is estimated to contain one-fourth[5] of the reserves of the Pittsburgh coal in the state. The most extensive mining, primarily by steel companies, has occurred along the Monongahela River, where the Pittsburgh coal outcrops, and within ten miles on either side of the river. The index map shows the Gateway Mine to be located along the western edge of this belt. Greene County originally contained 361,000[5] acres of the Pittsburgh bed.

Figure 33: Structure Map

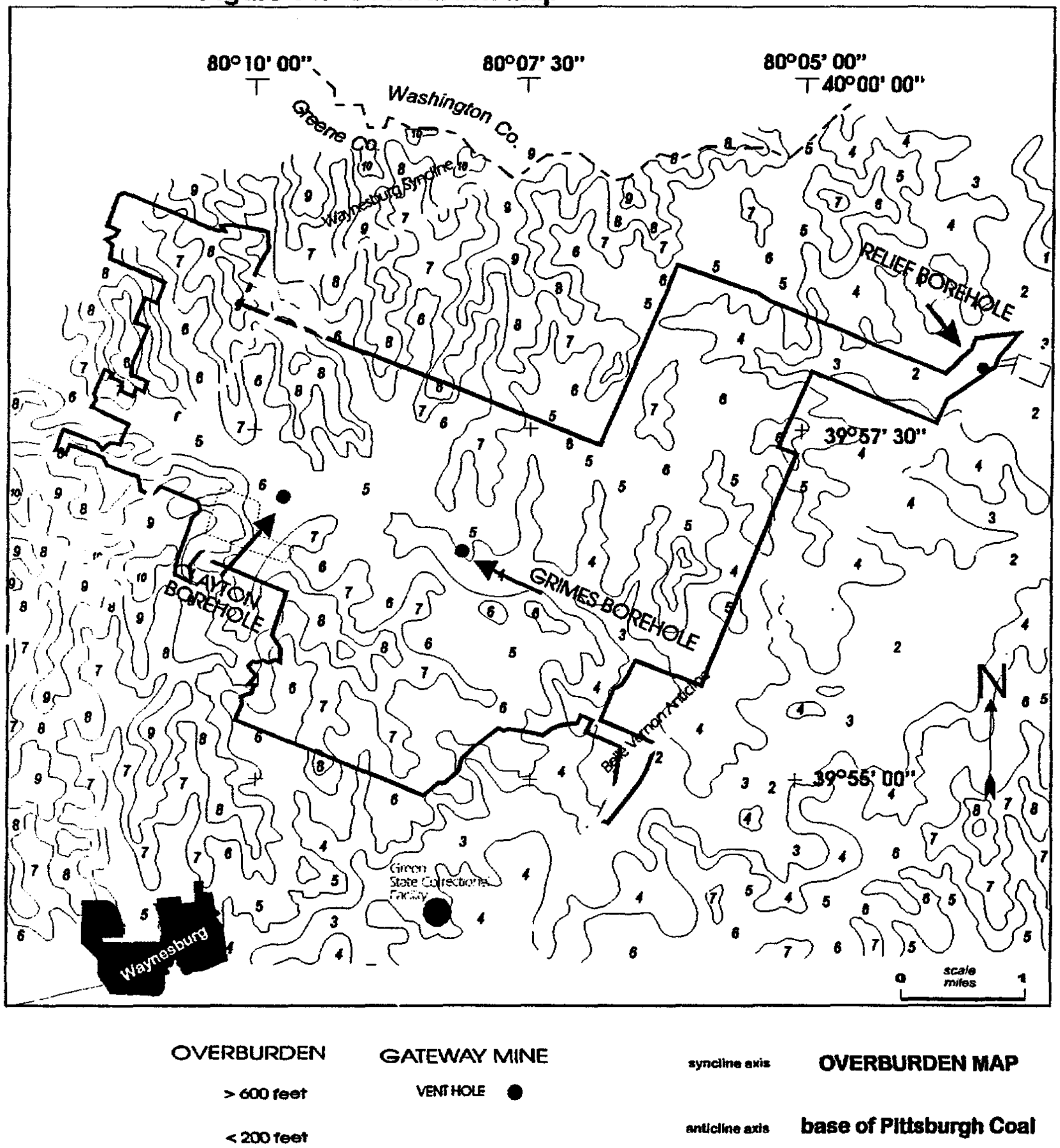


The Gateway mine originally opened in the 1950's and was used to supply coal for Jones & Laughlin (J&L) Steel Company. The mine has been through at least two subsequent changes in ownership. Room and pillar was the primary method used to mine the Pittsburgh coal seam, although longwall mining was employed at a later date. The major portion of the mine was sealed around 1990[6]. Longwall operations still continue in the "Lazarus" Mine.

Bordered by the axis of the Belle Vernon Anticline on the east, the 8,900 acre Gateway mine lies on the gently sloped western flank of the NE-SW trending Belle Vernon Anticline and extends into the Waynesburg Syncline on the west, as shown in Figure No. 42, above. Structurally[7], the Pittsburgh coal is found from 400 feet above sea level in the western portion of the mine in the Waynesburg syncline, to 600 feet above sea level at the eastern edge of the mine near the crest of the Belle Vernon anticline. The Pittsburgh coal from the Grimes borehole in the central mine area lies at 500 feet above sea level.

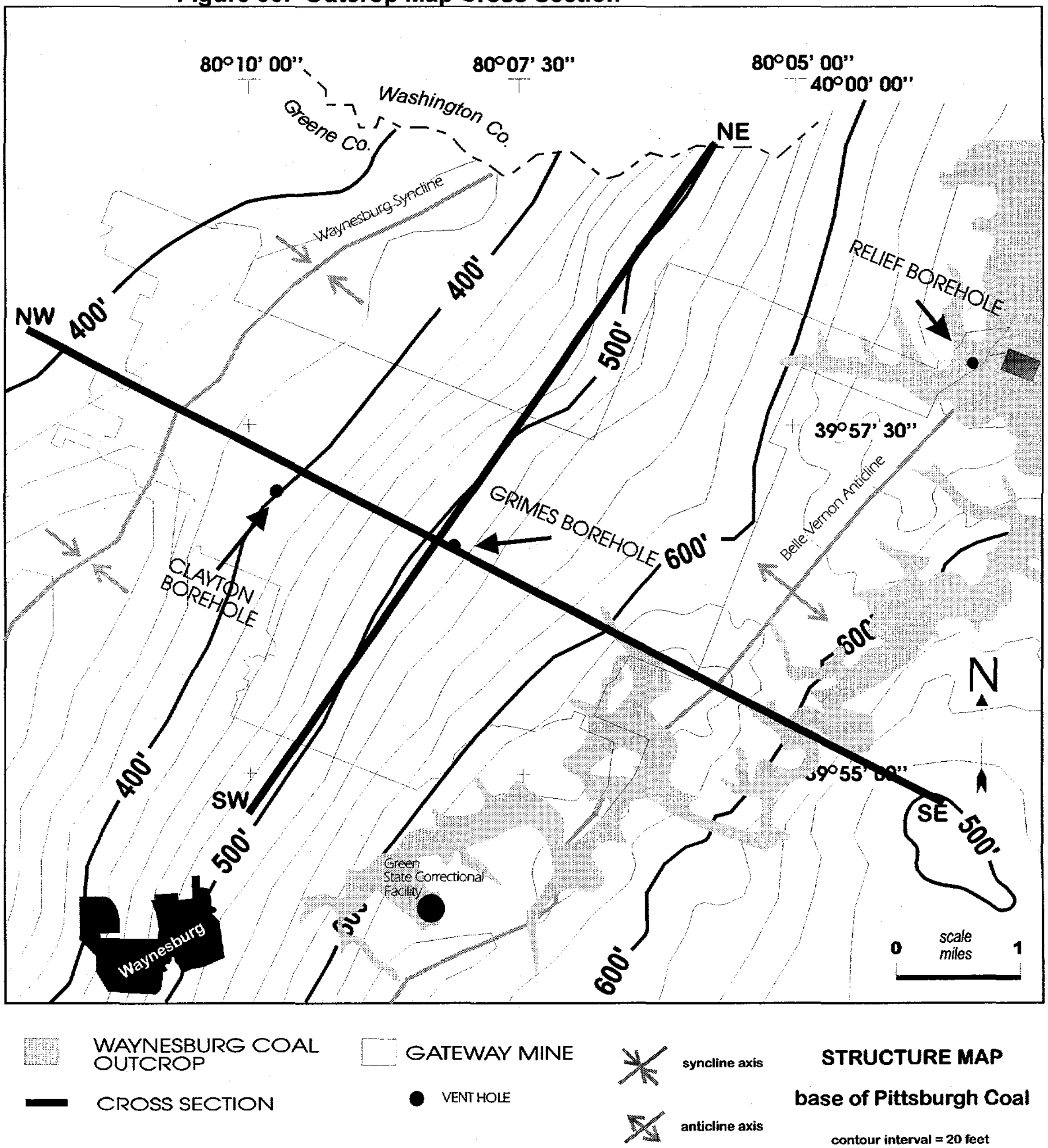
Overburden to the Pittsburgh coal ranges from over 900 to less than 300 feet, with an average of 500 feet of overburden in the vicinity of the gob and relief wells drilled along Ruff Creek, as shown in Figure No. 34. The borehole locations are also indicated on this map.

Figure 34: Overburden Map



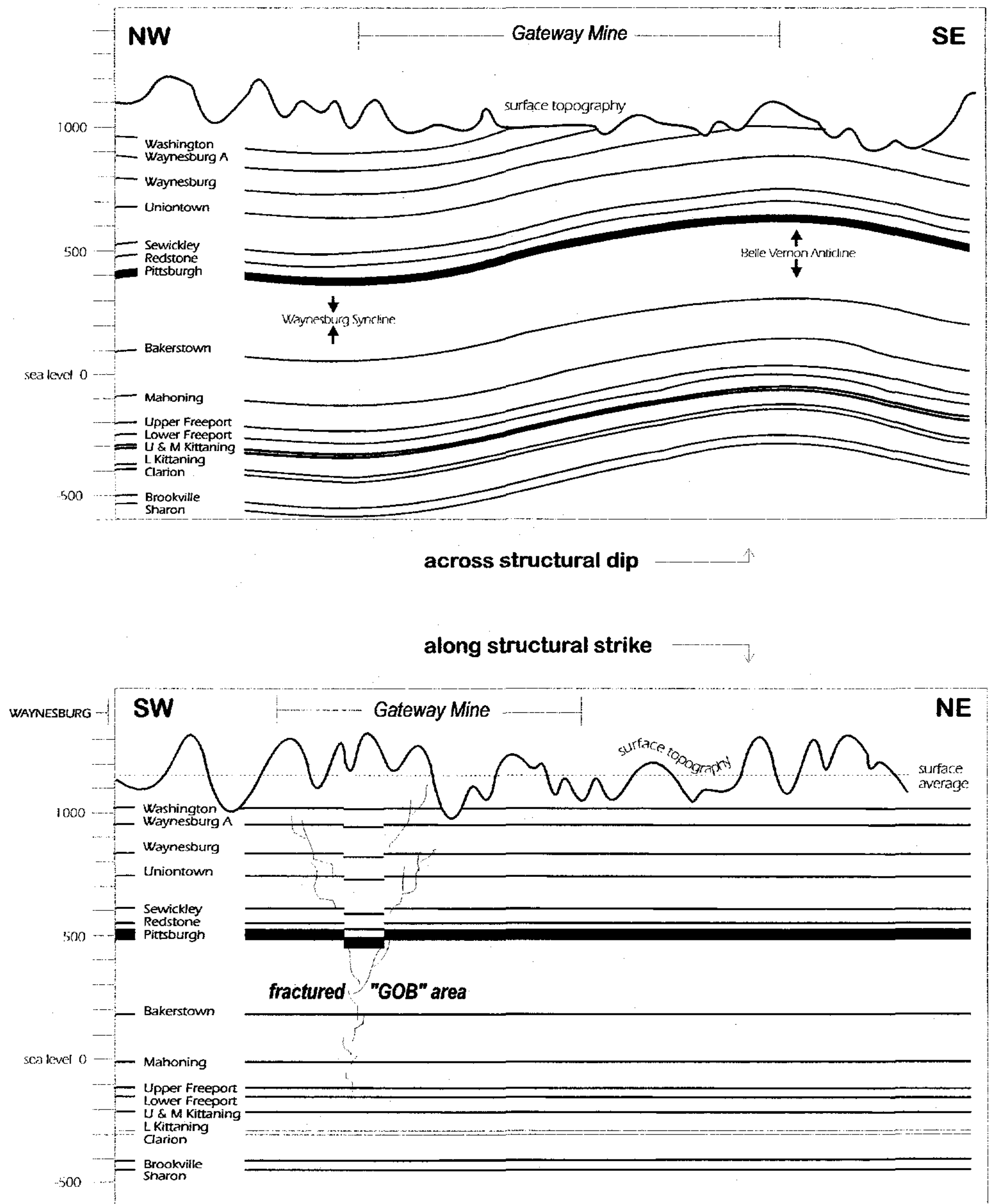
The coal seams estimated to contribute most extensively to the gob gas production are the Waynesburg, Sewickley, and Pittsburgh, which belong to the Monongahela Group coals of Pennsylvanian age. Due to the room and pillar mining method, approximately one-half of the Pittsburgh coal remains. The Waynesburg and Sewickley, while thinner than the Pittsburgh, form widespread and continuous seams throughout Greene and into adjacent counties. The Redstone coal, lying just above the Pittsburgh, is also present. Figure No. 35 shows the outcrop of the Waynesburg coal along portions of Ruff and Ten-Mile Creeks. Part of the Waynesburg outcrops before the crest of the anticline which may have resulted in partial desorption of the Waynesburg coal.

Figure 35: Outcrop Map Cross Section



Two cross-sections were constructed to illustrate the coal stratigraphy under the Gateway Mine property. The location of these cross-sections is shown in the previous Figure No. 35. One cross-section follows the structural strike of the coal beds and another is along the strike of the creek (roughly structural dip). Both sections show the intervals, in feet, between the significant coal measures (See Figure No. 36). Fracturing of the gob (due to collapse of the mined-out area) is also "cartooned" in one of the cross-sections.

Figure 36: Strat Cross Sections



STRATIGRAPHICAL CROSS SECTION OF COALS

As seen from the previous figures, although much of the coal is more shallow than the Waynesburg outcrops over portions of the mine area, deeper coals are present from 300 to over 900 feet below the Pittsburgh coal. In particular, the Freeport coal is a thick, continuous seam lying 600 feet beneath the Pittsburgh coal. The propagation of fractures due to gob formation from collapse of the mined-out area may extend to some of these deeper coals, and contribute to the gas reserves. Several tight sands interspersed in the stratigraphic layers associated with the coal seams may also initially produce gas when fractured.

B. GREENE COUNTY COAL GEOLOGY

History of Coal Mining in Pennsylvania

The earliest record of bituminous coal mining in Pennsylvania is that of 1760, when, according to Captain Thomas Hutchins, a coal mine was opened on the Monongahela River, opposite Fort Pitt, now Pittsburgh. Coal was first shipped from Pittsburgh in 1803, when the *Louisiana* was ballasted with coal that was sold at Philadelphia for 37.5 cents per bushel. The great growth of the river coal trade began with the completion of the Monongahela Navigation Company's system of locks to Brownsville in 1844[5]. Even today, coal is transported by barge down the Monongahela and Ohio Rivers. However, the focus for coal use has shifted from heating to steel manufacturing to power generation. Current regulations regarding NO_x emissions from power generation have resulted in the investigation of technologies to reduce these emissions.

Total Coal

Greene County has at least eight mineable coals. The Pittsburgh coal is mined throughout the region, while the other coals can be commercially mined only locally where there is sufficient seam development. Where the coal seams are mined, approximately half of the coal remains and will contribute to GOB gas production. Thirteen coal beds outcrop while thirty beds are known in the county. These coals range from a few inches to 6 feet thick, but average less than a foot in thickness. Their total average thickness in Greene County approximates 25 feet[5]. The estimated thicknesses for the coals on the Gateway Mine property is shown on the following Table No. 9. Coals are in order from shallowest to deepest. Coals shallower than the Washington are not included, since they are mostly eroded, and therefore not present. The total coal thickness of the Pittsburgh and shallower coals is estimated to be nearly 20 feet. These coal beds are included in the model as contributing to GOB gas production. The deeper coals beneath the Pittsburgh are equal in total thickness to the Pittsburgh and shallower coals, nearly doubling the coal thickness beneath the Gateway Mine property. However, the extent to which fracturing from the GOB areas will affect these deeper coals has not been estimated and they are not included in the GOB production forecasts at this time. They may or may not contribute to actual GOB gas production.

Table 9: Estimated Average Thickness of Coals - Gateway Mine

Group	Coal	Avg. Thickness (Ft)
Washington (Dunkard)	Washington	2.00
	Waynesburg A	1.25
Monongahela	Waynesburg	5.00
	Uniontown	1.00
	Sewickley	3.00
	Redstone	1.00
	Pittsburgh	6.25
Conemaugh	Bakerstown	1.25
	Mahoning	1.75
Allegheny	Upper Freeport	6.00
	Lower Freeport	2.50
	Upper Kittaning	1.75
	Middle Kittaning	1.75
	Lower Kittaning	2.00
	Clarion	1.00
Upper Pottsville	Sharon	0.50
	TOTAL	**38**

Following is a summary of Greene County coals, in order of decreasing age:

Freeport and Other Deep Coals

Coals of the Conemaugh and Allegheny Group are found beneath the Pittsburgh seam. The Bakerstown and Mahoning coals of the Conemaugh Group are present in Greene County, and core data indicates that they average between one and two feet in thickness. One bed averaging 30 inches thick is found 625 to 720 beneath the Pittsburgh coal which correlates with the Upper Freeport coal of the Allegheny Group in Washington County[5]. In the Gateway mine area, this Upper Freeport coal seam reaches 6 feet in thickness[8]. Beneath this Upper Freeport coal, the Kittaning, Brookville and Clarion coals of the Allegheny Group have been identified from core. Where present, they are comprised of thin beds, often averaging less than two feet thick.

Pittsburgh Coal

The Pittsburgh coal outcrops along the valley of Monongahela River and its tributaries on the eastern border of the county and also up Dunkard Creek about five miles. The Pittsburgh coal is probably mineable everywhere in Greene County but it varies in thickness. It has good coking qualities and during the 1920's was bought up by large steel companies as a reserve of by-product coal. This coal is characteristically a double bed, having a roof division separated from a lower division by a clay parting from a quarter inch to three inches thick. In Greene County, the roof division of the Pittsburgh bed thickens and the lower division thins northward. The roof coal is around a foot in thickness while the mineable coal averages 6 to 7 net feet in thickness and can reach a maximum of 9 feet[5]. Coal core data from the southeastern portion of the Gateway Mine indicate an average main seam thickness of around 6'3" with an average range of 5'10" to 7 feet. Locally the coal can be thin or absent due to the presence of channels in the depositional environment. Roughly half of the original Pittsburgh coal reserves remains in the Gateway Mine.

Redstone Coal

The Redstone bed lies 50 to 70 feet above the Pittsburgh coal and is persistent in the county but is rarely mineable, its average thickness being less than 18 inches. Its horizon is often marked by black shale carrying a few inches of coal. Along the Monongahela River the bed is represented by 13 feet of bituminous shale; back from the river the coal is a few inches thick, and clean[5].

Sewickley Coal

The Sewickley coal lies about 120 feet above the Pittsburgh coal and averages 2 feet in thickness. It thickens to 4 feet in the Dunkard Creek area, where it is known locally as the Mapletown coal, from outcrop and mining near that town. In southeastern Greene County, (south of Dunkard Creek), the Sewickley thickens rapidly to 6 feet, where it extends southward into West Virginia[5]. The Sewickley is around 2 feet thick over the northern half of the Gateway Mine in the area north of Ruff Creek, but thickens to between 2 and 4 feet in the southern half of the mine area between Ruff and Ten-Mile Creeks.

Uniontown Coal

The Uniontown coal, lying from 60 to 90 feet below the Waynesburg coal, rarely exceeds 12 inches thick, and in many places the horizon is marked by bituminous shale[5].

Waynesburg Coal

The most significant bed above the Pittsburgh coal is the Waynesburg. Found 330 feet above the Pittsburgh coal in the Gateway Mine area, the Waynesburg ranges from 5 to 9 feet thick in the eastern portion of Greene County, and is often separated into two beds by a three inch to 30 inch thick shale and clay parting.

A persistent bed 40 to 80 feet above the Waynesburg coal, the Waynesburg A ranges from 14 to 24 inches and is represented in many localities by a few feet of bituminous shale[5].

Concurrent with the rise in structure, these coals outcrop in the eastern portion of Gateway Mine property, primarily in the creek beds, and may be partially desorbed.

Washington Coal

Lying 140 to 180 feet above the Waynesburg coal, the Washington coal is the most persistent of the Dunkard coals, although thickness is variable and irregular and measures are separated by several shale, clay and bone partings. Rarely reaching mineable thickness in Greene County, it thickens to the north in Washington County[5]. This coal outcrops on the Gateway Mine property but is present over the western half of the property area.

Miscellaneous Shallow Coals

The Jollytown coal, which lies 150 to 200 feet above the Washington coal, was mined locally for domestic use in the Dunkard Creek region. It has an average thickness of less than a foot. In addition, there are several thin coals in the upper part of the Greene formation that nowhere exceed a few inches and are not mined. They are, in ascending order, the Tenmile, Dunkard, Nineveh, and Windy Gap coals[5]. Due to surface erosion, most of these shallow Dunkard coals above the Washington coal seam are not present over the Gateway Mine. Where they exist, they have limited extent and are probably desorbed.

IV. Utilization Evaluation

A. Design Trade-Off of Cost

1. Resource Considerations on Turbine Size

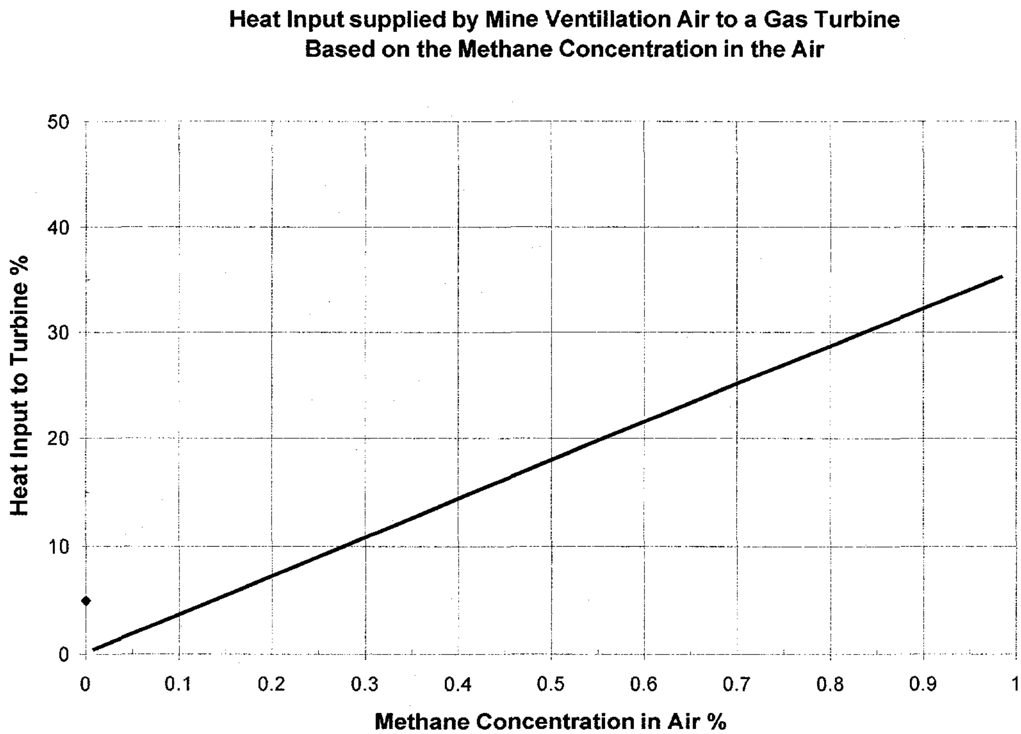
The coal-bed methane production capacity of the Gateway mine has been estimated to be about 1 MMCFD of gas at 100% methane concentration. This resource alone would be sufficient to supply a 3 megawatt (MW) gas turbine assuming a generating heat rate of about 14,000 Btu/kW-hr.

It has been proposed that mine ventilation air containing a low concentration of methane be used as the turbine's combustion air source. When the ventilation air is used in this way, the methane contained in the ventilation air will supply a portion of the turbine fuel. Figure 37 illustrates the percentage of turbine heat input supplied by mine ventilation air based on the methane concentration in the air. Mine ventilation air must contain less than 1.0% methane in a working coal mine and may typically contain 0.2% to 0.6% methane.

Ventilation air from the Lazarus mine was reported by the U.S. Bureau of Mines (USBM) in 1993 to contain 0.6% methane and to emit approximately 1 MMCFD of methane. This corresponds to an average ventilation air flow of about 7 MMCF/hr. A 4 MW gas turbine requires less than 1.5 MMCF/hr of combustion air. Therefore, the ventilation air from the Lazarus mine could supply all the gas turbine's combustion air requirement. In addition, methane emissions to the atmosphere from the Lazarus ventilation air system would be reduced by about 20%.

Based on the methane concentration in the ventilation air, approximately 22% of a turbine's heat input could be supplied by the methane contained in the air. With this ventilation air energy resource, the maximum turbine size could be increased to about 3.8 MW. These resource considerations indicate the size of gas turbine suitable to the available resource but do not indicate the size which is economically feasible at the proposed site. It also does not indicate whether or not it is economically desirable to utilize the mine ventilation air.

Figure 37: Heat Input vs. Methane %



2. Potential Electrical Customers - Impact on Design

The gas resources indicate that a turbine size as large as 3.8 MW would be feasible. However, the electrical demands of potential customers and competitive electrical rates may be the primary determinate of the economically feasible generating capacity. Potential electrical customers include:

1. West Penn Power, Greensburg, Pennsylvania The Gateway mine is within the West Penn Power service territory. Power generated using a waste gas stream such as gob gas or mine ventilation air could be sold to West Penn Power at their avoided cost of generation. West Penn Power currently has excess generating capacity and therefore its avoided cost of generation is the cost of energy replacement alone without a demand or capacity component. West Penn's avoided energy costs are currently about 1.7 cents/kW-hr. West Penn Power projects the need for additional capacity in about five years. Future power purchases will be obtained through competitive bidding; and accordingly, the future price will be established by competitive market forces.
2. State Correctional Institute (SCI) in Greene County The SCI-Greene facility is about 4 miles south of the center of the Gateway Mine and about 1 to 2 miles south of mine property. This facility has an average electrical demand of about 1.1 MW, although the electrical use it still below what is expected at this new facility. The electricity purchased by this facility averaged 4.6 cents/kW-hr over a ten-month period in 1994 and has been higher than 5.0 cents/kW-hr in 1995. This facility may also have a heating load for hot water making it potentially attractive for a cogeneration system of electricity and hot water/steam.
3. Lazarus Coal Mine The Lazarus Coal Mine would also be a potential customer for electric power. No information is currently available on the mine electrical power consumption or electric purchase rate.

3. Design and Cost Trade-Offs

An opportunity exists to utilize mine ventilation air containing about 0.60% methane to supply a zero cost portion of a gas turbine's fuel requirement. However, because the ventilation air contains only a small amount of energy per air volume, it is not economically attractive to move the air very far to accommodate the turbine. A better approach is to site the turbine at a location accessible to the discharge from the mine ventilation shaft and utilize the positive fan discharge to transport combustion air to the turbine.

Installing the turbine to take advantage of the mine ventilation air may have the disadvantage of precluding cogeneration opportunities at SCI-Greene due to the 6.5 mile distance between the Lazarus mine and SCI-Greene. This distance would be too great to economically transport thermal energy in the form of hot water or steam. However, this distance would not preclude the economic transport of electric power generated at the Lazarus mine to the SCI-Greene facility.

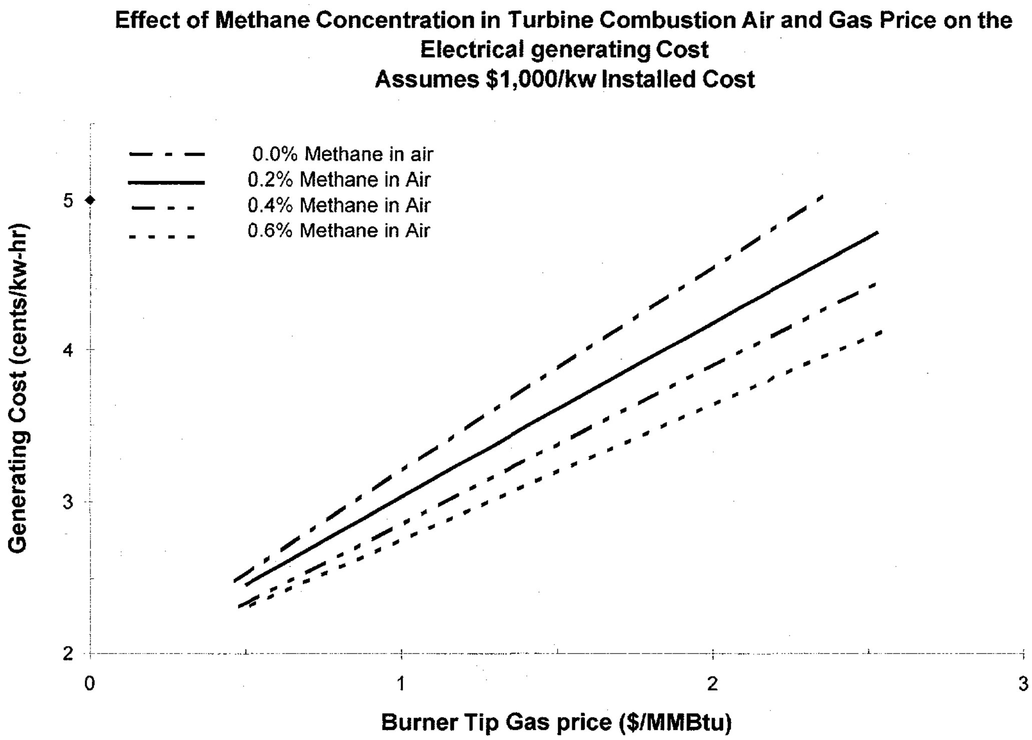
The distance from the Gateway mine where the primary fuel would be produced to either the Lazarus mine or the SCI-Greene facility is within 3 to 5 miles. This distance would not limit the economic feasibility of transporting a high concentration methane fuel either to the Lazarus mine or to SCI-Greene or the feasibility of transporting electrical power to either location.

The economic attractiveness of using mine ventilation air is dependent on the concentration of methane contained in the air as well as the cost of supplying a higher quality primary fuel. Figure 38 illustrates the cost of electrical generation (cents/kW-hr) as a function of primary fuel cost and the concentration of methane contained in the ventilation air. This example assumes an installed turbine capital cost of $1000/kW. This figure supports several logical conclusions.

- First, the value of using the mine ventilation air increases as the primary fuel price increases and as the concentration of methane contained in the air increases.
- Second, at a very low primary fuel price of $0.50/MMBtu, the incremental value of using the mine ventilation air containing 0.6% methane is only 0.2 cents/kW-hr.

Accordingly, at a gas price of $0.50/MMBtu it is not economically significant to use the mine ventilation air particularly if installation requirements near a mine ventilation shaft result in increased cost of gas supply or electrical distribution.

Figure 38: Burner Tip Price vs. Operating Cost



At a higher primary fuel price the value of using the mine ventilation air increases. At a gas price of $2.50/MMBtu the use of mine ventilation air results in a $0.80 /kW-hr lower generating cost. At a gas price of $2.50/MMBtu, the use of the ventilation air results in lowering the generating cost from 5.2 cents/kW-hr which is currently too high to be competitive at SCI-Greene to 4.4 cents/kW-hr which would be competitive.

A more detailed analysis is required to evaluate the feasibility of providing electrical and thermal energy to the SCI-Greene facility. This option would require placing the cogeneration plant at SCI-Greene and transporting primary fuel from the Gateway mine. This option would not include the use of mine ventilation air.

If it is not feasible to provide thermal heat to SCI-Greene, then the turbine facility could be located at the Gateway mine or at the Lazarus mine. The turbine would only be located at the Lazarus mine for purposes of utilizing mine ventilation air. The use of ventilation air would also require more detailed analysis to determine, the expected life of a discharge ventilation shaft, the expected future methane concentration, and the impact of degasification practices on future methane concentration in the ventilation air.

The cost of transporting electricity and/or primary fuel between the various potential turbine sites or power customer locations should be considered.

B. Cost Per kW-hr of Electricity & Sales

The cost of generating electricity using a gas turbine is dependent on the capital cost of the installed generating equipment, the operating and maintenance cost of the equipment, the turbine efficiency, the equipment availability, the cost of fuel, the life span of the investment and the cost of project financing.

Single cycle gas turbines operate at relatively low efficiencies in comparison to utility coal-fired steam generators. Consequently, turbines are more frequently utilized as electrical peaking units rather than as base loaded competitors to coal-fired generation. Gas turbines of 100 to 1000 kw size may have efficiencies as low as 17% based on the higher heating value of the fuel, while efficiencies as high as 33% are claimed for larger units. A gas turbine of approximately 3 to 4 MW capacity could be expected to achieve a generating heat rate of about 14,000 Btu/kwhr. In comparison, large coal-fired steam generators achieve heat rates of approximately 10,000 Btu/kwhr.

Turbine availability will impact the overall economics of generation. The higher the turbine availability, the higher the net generation and the lower the associated fixed capital cost per kilowatt of electricity generated. The availability of a gas turbine should be 85% to 90%. Generating cost analysis which follows are based on an availability of 85%.

A useful life of the gas-fired turbine is assumed to be 25 years to be consistent with the projected gas reserves. The cost of capital financing has been assumed to be 7.5%.

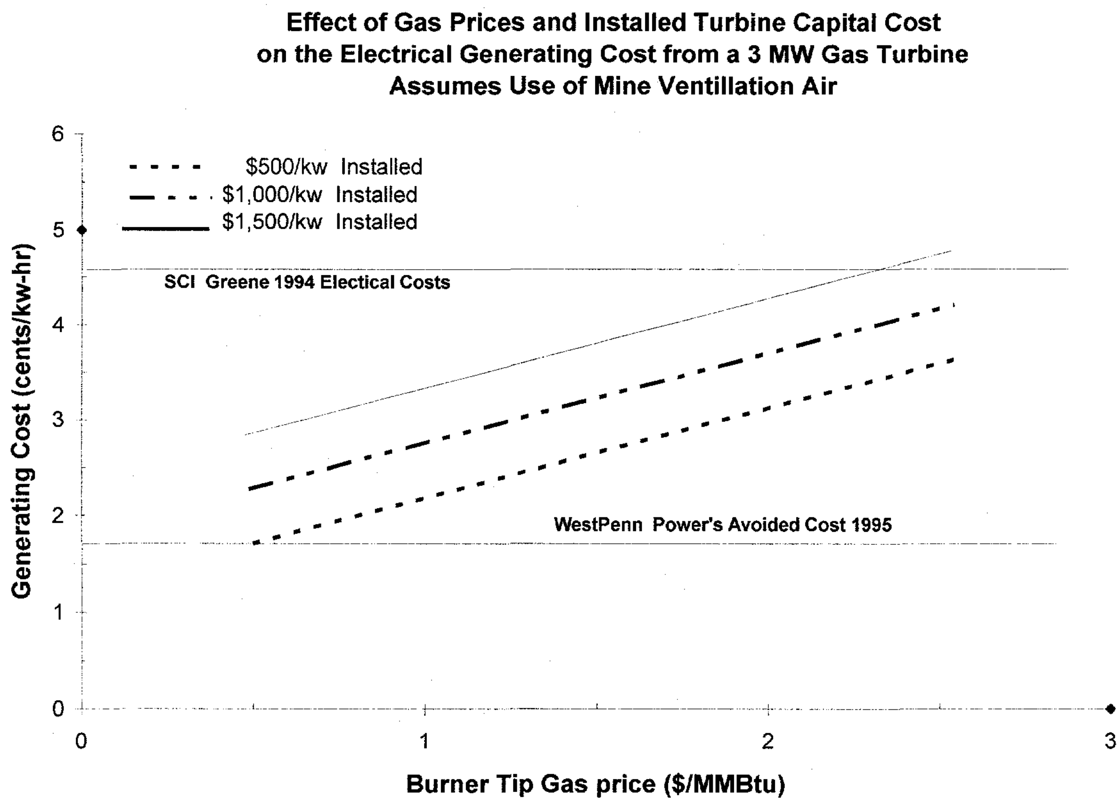
The operating and maintenance costs (O&M) of a gas turbine are conveniently estimated at a fixed rate per kW-hr of generation. For purposes of this analysis, the O&M costs have been estimated to be 0.50 cents/kW-hr.

Installed capital costs for gas turbine projects of this size would be expected to cost about $1000/kw of installed capacity. Figure 39 illustrates the turbine generating cost per kW-hr based on the fuel cost and at a range of installed capital costs from $500/kW to $1500/kW. Lines have been placed on this figure which represent the avoided cost for West Penn Power and the average 1994 purchase price at SCI-Greene. This figure uses the previously listed operating and economic assumptions. In addition, it was assumed that mine ventilation air containing 0.60% methane would be used as the turbine combustion air source.

This figure illustrates several important facts. The avoided cost within the West Penn Power service territory is so low (1.7 cents/kW-hr) that it does not appear economically feasible to generate electricity for sale to West Penn Power at their avoided cost. As Figure 39 illustrates, even at a burner tip gas price of $0.50/MMBtu, the generating cost at the expected capital cost of $1000/kw is 2.2 cents/kW-hr. This is well above West Penn Power's current avoided cost. This price would probably be competitive with future power purchase costs within the West Penn Power system.

A more attractive option would be to sell electricity to the State Correctional Institute (SCI) in Greene County or to the Lazarus mine at a similar price to SCI-Greene. SCI-Greene is within 6.5 miles of the Lazarus mine site. Current electrical demand at SCI-Greene is about 1 MW, although still below the expected demand at this new facility. The power purchased by SCI-Greene averaged 4.6 cents/kW-hr over a ten-month period in 1994 and has exceeded 5.0 cents/kW-hr in 1995.

Figure 39: Gas Price with Ventilation Air

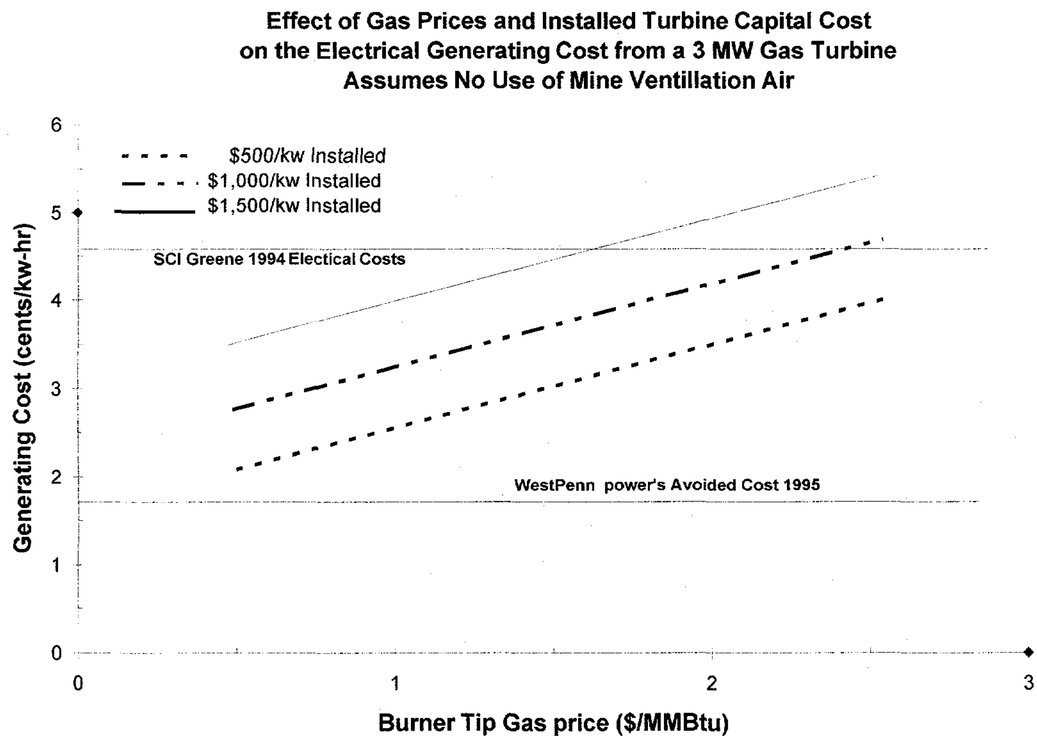


The primary turbine fuel price could reach $3.00/MMBtu before the generating cost reaches 5.0 cents/kW-hr if the mine ventilation air is used

Figure 40 illustrates the turbine generating cost as a function of the primary fuel price for various turbines' installed capital costs when no mine ventilation air is used. Since, the ventilation air is no longer providing a portion of the fuel at zero cost, the primary fuel use and generating costs increase. At a turbine installed capital cost of $1000/kW the gas price could reach only $2.34/MMBtu before the generating cost reaches 5.0 cents/kW-hr.

These preliminary generating cost analyses indicate that it will be feasible to generate power for sale to SCI-Greene or the Lazarus mine. The opportunity to cogenerate at SCI-Greene and provide thermal energy may increase the overall project revenue. Cogeneration would come at the expense of ventilation air use since it is not feasible to transport ventilation air to SCI-Greene from the Lazarus mine and or to transport thermal energy from the Lazarus mine to SCI-Greene.

Figure 40: Gas Price with No Ventilation Air



C. *Safety Considerations*

Power Supply

Mine ventilation must be continuous. It is not possible to allow the ventilation to fans to stop as the gas continues to flow out of the coal. The gas turbine, if it is to use the ventilation air, must draw in this air in such a manner so that the operation or non-operation of the turbine does not affect the exhaust of the air from the mine.

The power for the mine ventilation exhaust fans must be ensured. If the turbine is to supply the power for the ventilation fans there must be backup power.

The power for SCI-Greene must be continuous. Backup power in terms of redundant gas turbines or supply from West Penn Power will be required.

Assured power supply to the users is the most pressing safety consideration.

GOB Gas as a Turbine Fuel

The use of gob gas as a gas turbine fuel has certain safety implications. The supply, and quality of the gas must not vary over too large a range.

It is best if the gob gas can be supplied in amounts sufficient to meet the requirements of the gas turbine. The turbine should not need to follow the gas supply nor the ambient pressure. The pressure should be produced be operating an electrically-driven compressor. Depending on the turbine, 200 to 350 psi, will be required.

The supply can fail, due to failure of the gas compressor, rupture or blockage of the gas supply line, or other cause. The turbine will have safety which will trip the unit in case of the fuel pressure loss. The loss of gob gas pressure should not be a safety problem.

By some mechanism, air could leak into the gob gas. This would become a safety problem and the supply lines could explode. There could be an explosion in the fuel supply elements of the gas turbine. However, it should not cause a problem in the combustor nor in the turbine itself. It is necessary to assure that the gob gas does not become a mixture of air and methane.

Mine Ventilation Gas as Turbine Working Fluid

In gas turbines the working fluid is also the oxidizer. In order to control the temperatures, a large excess of air is used in a gas turbine. This excess does not control the peak flame temperature nor the NOx emissions. However, it limits the temperature that the expansion turbine experiences. In this case, the ventilation air will also supply part of the fuel. We expect the ventilation gas to have about 0.6% methane in it. At this level it is well below the lower flammability limit of methane in air. At ambient temperatures the lower flammability limit is 5.3%. The mine and the ventilation circuit are operated to maintain methane levels at 1.0% or lower in working areas and 2% or lower in other areas so there is no possibility of the ventilation air becoming an explosive mixture or causing an explosion.

D. Enthalpy and Coalbed Methane Utilization

Gob Gas

The coal bed methane, gob gas, at the Gateway Mine has 43 to 62% methane, Table 4. This amount is more than enough to operate a gas turbine. However, since the gas needs to be compressed to the working pressure of the turbine in a device that may be somewhat less efficient than the compressor of the gas turbine, there may be a small energy penalty due to the lower energy in the gob gas as compared to pipeline-quality natural gas. The increased amount of fuel can be offset by reduced air. Therefore, the total compression work is not changed; but, a small amount of the compression is done at a lower efficiency.

The gob gas, as shown in Table 4, is diluted with nitrogen, carbon dioxide and other gases with very little oxygen. This is significant for NOx emissions. If it were diluted with a small amount of air and nothing else, the peak flame temperature of stoichiometric combustion would be the same as the peak flame temperature of air and methane. The NOx would not be changed by such air dilution. However, methane diluted with a small amount of nitrogen and carbon dioxide will burn with a slightly lower peak flame temperature. At 50% methane and 50% dilutants the total combustion products may be increased by 10%. This will decrease the peak flame temperature by 10%. The NOx emissions may be decreased by as much as 50% by such a change in the fuel composition.

The gob gas is suitable as a gas turbine fuel or as a heating fuel without qualification.

Ventilation Air

Ventilation air from the Lazarus mine is believed to have about 0.6% methane in it. When this exhaust air is used as the combustion air in a gas turbine, it will supply about 22% of the fuel needed to operate a gas turbine. Only 78% of the fuel will need to be supplied as natural gas or gob gas. This will result in an important energy savings. In addition, this pre-mixed air and fuel, with the fuel being very dilute, will burn at a very low temperature. The combustion of this fuel will be at such a low temperature that it should produce no NOx.

Now we have 22% of the fuel producing no NOx and the remainder producing at about 50% of the typical rate. The NOx emissions from the gas turbines should be only 39% as much as the usual gas turbine firing natural gas. The low NOx operation by use of ventilation air is covered in US Patent 5,261,876 " Method for Reducing Nitrogen Oxide Emissions from Gas Turbines" by J. Gabrielson and B. Breen, assigned to Consolidated Natural Gas.

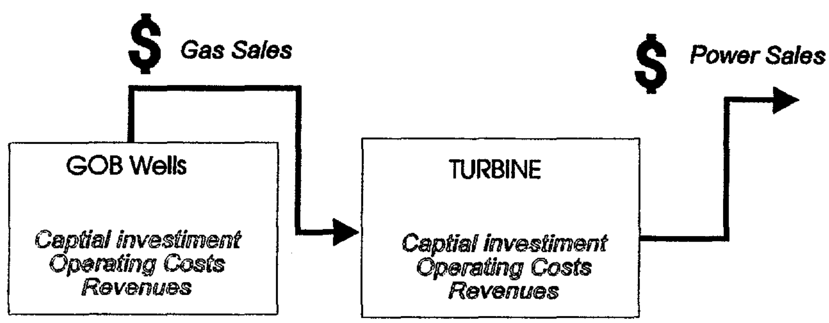
The use of the these gases will reduce the emissions of methane to the atmosphere.

V. Economic Results & Discussion

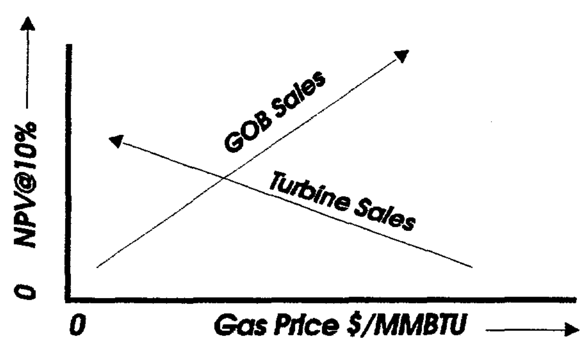
A. Overview

Economic sensitivity analyse were performed for all reserves cases evaluated. Sample cash flow tables are included, Table Nos. 10 and 11 (not all tables have been included). Economic analyse were performed individually for the GOB wells (drilling, completion, operating expense) and the turbine individually. The economics for the GOB wells were run at different gas price ($2.00 - $0.25 per MMBTU) scenarios. The intent was to determine what gas price (break even burner tip fuel price) would yield acceptable drilling economics as the price of gas to be utilized as fuel for turbine electric power generation.

The following chart illustrates the economic analysis basis:



The economics of the turbine are directly related to the cost of gas as the following figure indicates. As the cost of gas increases, the resulting NPV to the turbine decreases. This segmented analysis was performed to allow for flexibility in evaluation of turbine options.



The economic evaluation will also allow differing equity participants to assess their own economics, if ownership is partitioned between gas rights (GOB wells) and equity ownership in the turbine, as may be the case in this project. (Negotiations still have to be consummated.)

B. GOB Well Economic Evaluation

The following table summarizes basic input assumptions. It should be pointed out that gas prices were not inflated during the evaluation period of 25 years.

Parameter	
Gas price inflation:	**0%**
Operating Expense inflation/yr.	**5%**
Avg. Well Capital cost	$42 M
Compression	$30 M
Pipeline per well	$5 M
Operating Cost/Well per mo.	$200
Local Taxes	**11%**
Corporate Tax Rate:	36%

Economic sensitivities were run based on the following production forecast and reserve levels as a function of (P_{wf} - P_{ft}) derived from the analytical model outlined above.

No. Wells	**10**				**20**			
Inches Wg. - (P_{wf} - P_{ft}).	2"	4"	6"	8"	2"	4"	6"	8"
Total Coal Thickness - ft.								
6	X	X	X	X	X	X	X	X
12	X	X	X	X	X	X	X	X
36	X	X	X	X	X	X	X	X

Gas prices were varied from $2.00 to $0.25 per MMBTU for the production and reserve estimates. Net present value (after tax) graphs are presented below:

Figure 41 NPV@10% vs Reserves and Gas Price

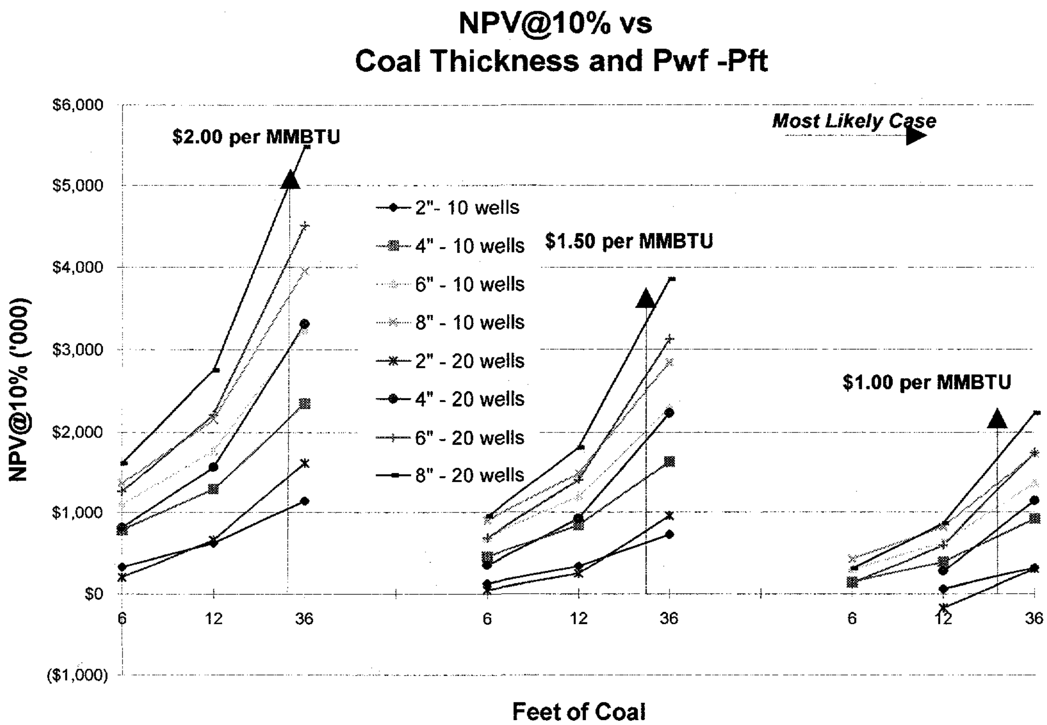


Figure No. 41 summarizes most of the economic analyse for GOB well drilling. Lower gas prices are not shown as they returned either unacceptable economics or did not apply to the most likely case which is indicated by the arrow. Based on the geologic discussion, UEDC anticipates that around 30 feet of total coal is present. It should be pointed out that gas contained in sandstone reservoirs, which may be present in the area, are not included in this analysis.

The following economic model input and cash flow table were designed for the economic evaluation of gas or oil wells and was modified for this application:

Table 10: Model Input Data

COST DATA

NO. WELLS: 10

COSTS:'$000's	Tangible	Intangible	**Try & Dry-$000's**	
Drilling-	$20	$350	**$370**	
Completion-	$30	$7	**$37**	P&A
Stimulation-	$0	$10		
Total	$50	$367	$407	
TOTAL WELL COST	**$417**			
FACILITY-'$000's				
Compressions-	**$30**	$6		
Pipeline-	**$40**	$8		
Artificial lift-	**$0**	$0		
Saltwater disposal-	**$0**	$0		
Total	$70	$14		
Grand Total	**$84**			
LEASE/SEISMIC-$000's				
Total	**$0.000**			
OPERATING EXPENSE: -$000/mo				
Direct-			$1.00	
Indirect-			$1.00	
Total			$2.00	
Success Ratio:		**100%**		
Corporate Tax Rate		36%		
Depreciation Expense	**1**	*1=YES* *0=NO*		

GATEWAY GOB WELL ECONOMIC RESULTS

NET PRESENT VALUE TABLE

NPV@0%	$1,624.09
NPV@5%	$1,088.23
NPV@10%	$782.59
NPV@20%	$454.19
NPV@25%	$356.77
NPV@30%	$283.03
NPV@40%	$179.77
IRR	**84.06%**

ROYALTY INTEREST	**12.50%**			Royalty Interest	
WELL SPACING-AC	300		DISCOUNT	12.50%	Royalty/ac
VALUE PER AC.		$5,413.63	0.0%	$703.15	$2,343.84
		$3,627.44	5.0%	$499.82	$1,666.07
		$2,608.65	10.0%	$390.86	$1,302.88
		$1,513.95	20.0%	$279.80	$932.68
		$1,189.23	25.0%	$247.44	$824.79
		$943.42	30.0%	$222.70	$742.32
		$599.25	40.0%	$186.91	$623.04
$/acre Bonus **$0.00**					

Factor Production	**1**			
Gas Price	**$2.00**		Escalation Factor	**0%**
Reserves - 25 Yr.	**2812.61**	MMCf		
Royalty bonus	**$0.00**		**8953** acres	
Severance & Adv. Taxes	**6.00%**			
Operating Cost Esc. Fac.	**5.00%**			$/acre
Total royalty per acreage	$78.54	0.0%		$261.79

Table 11: Cash Flow Table

Year	Prod.	Prices	Revenues	Override	Royalty	Local Taxes	Direct & Indirect Exp		Operating Income Annual	Operating Income Cum.	Depreciation Expense	Federal TAX	CASH FLOW Annual	CASH FLOW Cum
	Gas MMCF/Yr	Water MBSW/Yr	Gas $/MCF	Gas $000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
FACT.	0.6	0.01	0%		12.50%	6.00%	5.00%	$ 0.05						
0											$283.56	($102.08)	($398.52)	($398.52)
1	540.61	0.00	**$2.00**	$1,081	$135	$65	$24.00	$0.00	$857.19	$857.19	$40.81	$374.55	$482.64	$84.13
2	321.77	0.00	$2.00	$644	$80	$39	$24.05	$0.00	$500.43	$1,357.62	$43.83	$215.89	$284.54	$368.66
3	214.01	0.00	$2.00	$428	$54	$26	$24.10	$0.00	$324.73	$1,682.36	$37.83	$140.47	$184.27	$552.93
4	170.11	0.00	$2.00	$340	$43	$20	$24.15	$0.00	$253.14	$1,935.49	$33.55	$110.41	$142.73	$695.66
5	144.02	0.00	$2.00	$288	$36	$17	$24.20	$0.00	$210.55	$2,146.04	$33.55	$91.61	$118.93	$814.59
6	126.17	0.00	$2.00	$252	$32	$15	$24.25	$0.00	$181.41	$2,327.44	$22.13	$82.88	$98.53	$913.12
7	112.98	0.00	$2.00	$226	$28	$14	$24.30	$0.00	$159.87	$2,487.31	$5.35	$79.42	$80.44	$993.56
8	102.75	0.00	$2.00	$205	$26	$12	$24.35	$0.00	$143.13	$2,630.43	$0.00	$73.98	$69.15	$1,062.71
9	94.51	0.00	$2.00	$189	$24	$11	$24.40	$0.00	$129.65	$2,760.08	$0.00	$68.05	$61.60	$1,124.32
10	87.71	0.00	$2.00	$175	$22	$11	$24.45	$0.00	$118.51	$2,878.59	$0.00	$63.15	$55.36	$1,179.68
11	81.97	0.00	$2.00	$164	$20	$10	$24.50	$0.00	$109.11	$2,987.71	$0.00	$59.02	$50.09	$1,229.77
12	77.06	0.00	$2.00	$154	$19	$9	$24.55	$0.00	$101.05	$3,088.76	$0.00	$55.48	$45.57	$1,275.34
13	72.79	0.00	$2.00	$146	$18	$9	$24.60	$0.00	$94.05	$3,182.81	$0.00	$52.41	$41.64	$1,316.98
14	69.04	0.00	$2.00	$138	$17	$8	$24.65	$0.00	$87.89	$3,270.70	$0.00	$49.71	$38.18	$1,355.16
15	65.72	0.00	$2.00	$131	$16	$8	$24.70	$0.00	$82.43	$3,353.13	$0.00	$47.32	$35.11	$1,390.27
16	62.75	0.00	$2.00	$126	$16	$8	$24.75	$0.00	$77.54	$3,430.67	$0.00	$45.18	$32.36	$1,422.63
17	60.08	0.00	$2.00	$120	$15	$7	$24.80	$0.00	$73.14	$3,503.81	$0.00	$43.26	$29.88	$1,452.50
18	57.66	0.00	$2.00	$115	$14	$7	$24.85	$0.00	$69.14	$3,572.95	$0.00	$41.52	$27.62	$1,480.13
19	55.46	0.00	$2.00	$111	$14	$7	$24.90	$0.00	$65.50	$3,638.44	$0.00	$39.93	$25.57	$1,505.69
20	53.44	0.00	$2.00	$107	$13	$6	$24.95	$0.00	$62.16	$3,700.60	$0.00	$38.48	$23.68	$1,529.37
21	51.59	0.00	$2.00	$103	$13	$6	$25.00	$0.00	$59.08	$3,759.68	$0.00	$37.14	$21.94	$1,551.32
22	49.87	0.00	$2.00	$100	$12	$6	$25.05	$0.00	$56.24	$3,815.93	$0.00	$35.91	$20.33	$1,571.65
23	48.29	0.00	$2.00	$97	$12	$6	$25.10	$0.00	$53.61	$3,869.53	$0.00	$34.77	$18.84	$1,590.49
24	46.81	0.00	$2.00	$94	$12	$6	$25.15	$0.00	$51.15	$3,920.69	$0.00	$33.70	$17.45	$1,607.94
25	45.44	0.00	$2.00	$91	$11	$5	$25.20	$0.00	$48.86	$3,969.55	$0.00	$32.72	$16.15	$1,624.09
Totals	2812.61	0.00		$5,625	$703	$338	$615	$0	$3,970	$74,128	$217	$1,947	$1,624	

C. *Turbine Economic Evaluation*

This mine is in the West Penn Power electrical sales area. West Penn Power has excess power and is not looking for nor paying for additional capacity from independent power producers. However, as required by law, they are paying their avoided costs for power. The avoided costs are only fuel costs and are evaluated as $0.017 per kWhr. This makes the sale of electricity to the power company very difficult. This is just slightly more than the annualized capital cost and the operating and maintenance costs. Almost nothing would remain for recovering and compressing the methane nor for purchasing the methane.

Pennsylvania has a correctional facility (SCI) at the south end of the property. The SCI-Greene facility uses about 1000 kWhr/ hr and pays a rate of about $0.045/kWhr. At this rate a profitable operation might be developed. One problem is that the Prison would need to pay demand charges even if they only rarely purchased electricity from West Penn Power. If only one turbine is constructed, then each time it were out of service, the SCI might need to purchase from West Penn Power.

An alternative approach would be to purchase two turbines, each of which would be large enough to operate the SCI and sell the excess power to West Penn Power. While some of the power would be sold at what may be regarded as distress prices, this procedure would assure that the Prison requirements could always be met from the coalbed methane.

The Prison has a heating load of about 136 MCFD. This could be replaced by hot water or steam generated from the waste heat from a gas turbine of about 350 kW. Since the Prison electrical is much larger than this, the total waste heat will be more than required for heating the Prison and supplying energy for the laundry and other thermal uses. The Greene SCI is not yet to capacity so the energy use figures we have are low. We are estimating that both the electrical and thermal uses of energy will increase by 25%.

It is possible that while the coalbed methane from this source is being developed for power generation, some of the methane could be delivered to SCI-Greene for use as heating fuel at prices less than the SCI is now paying, about $2.60 /MCF. We are considering using waste heat from one gas turbine to supply the SCI-Greene needs. The other turbine would be located at the mine and use mine ventilation air for its combustion air. Both turbines could service either SCI-Greene or the Lazarus mine and either would be adequate for the requirements for both users. The excess electrical power would be sold to West Penn Power. It is practical to transport either electrical power or 60% methane gas the 6.5 miles between the Larazus mine and the SCI. However, it may not be practical to transport either the mine ventilation air nor thermal energy as steam or hot water over such a distance.

For this case we are considering two 1700 kW gas turbines, one at the Lazarus mine ventilation shaft and one at SCI-Greene facility. The one at the mine would use ventilation air for its working fluid and would receive about 22% of its fuel from the methane in the ventilation air. The one at the SCI would use the 60% methane gas for all of its fuel, would have a waste heat recovery unit, and it would produce thermal energy for SCI-Greene. An electrical tie line would allow power to flow from either turbine to the mine or to the SCI-Greene facility.

A number of assumptions are needed to make an evaluation of this system:

The following Table 12 summarizes revenues and O & M costs for the options presented above.

Table 12: Turbine Economic Summary

Prison growth:	25%	
Electrical sales to SCI	1375	kW average
Electrical sales to mine	300	kW average
Electrical price to SCI and mine	$0.04	/kWhr
Heat sales to SCI, 1.25 times today's rate		
at 80% of today's price	$116,400	/year
Ventilation air supply	22%	of energy to one turbine
Capital gas turbines, tie line, heat recovery	$3,000,000	
Annualized cost of capital, 25 years, 7.5%	$274,000	
Operation &Maintenance @$0.005/kWhr	$126,582	/year
Total non-fuel cost	$400,582	/year
SCI Electrical (1375x8760x40.04)	$481,800	/year
Mine Electrical (300x8760x$0.04)	$105,120	/year
West Penn Electrical	$180,938	/year
Total revenue	$884,258	/year
Revenue Less non-fuel costs	$483,676	/year
Fuel use	318,987	million Btu
Break-even burner tip fuel price	**$1.51**	/million Btu

VI. Business Plan

The operation, as envisioned here, would be economical as a result of the electrical and thermal energy sales to SCI- Greene. In the text it was presented as break-even when the gob gas was available at the burner tip at $1.51 per million Btu. Another way to express this would be as payout period. Without showing capital recovery or interest payments, the net revenue per year divided into the capital cost would give the payout period. Using the example in V., C. Turbine Economic Evaluation, and the $1.51 per million BTUs, the payout period is 7.5 years. The general relationship with all of the fixed conditions given above is:

Payout in years = 9.4/(2.77 - Fuel cost in $/million Btu)

Burner Tip Gob gas price $/MMBtu	Payout, years
$0.00	3.4
$1.00	5.3
$1.51	7.5
$2.00	12.2

From this, one can see, that even with the cogeneration, the ventilation air, and the favorable electrical rate, gas prices of around $2.00 per million Btu probably cannot be supported. Thus, this operation could not afford to purchase its main fuel supply from a pipeline supply. Also, if the gob gas was of a quality to enter a pipeline, this power production might not be competitive with such a use of gob gas.

However, the use of this process is not dependent upon prisons or other outside power users, as attractive as they might be. Some mines are much larger than the Laszarus mine and may use as much as 3,000 kW. An economical process which involved only the mine could be arranged. The mine would supply the gob gas and the ventilation air and use the power.

It is hard to envision how the process could be developed with a local power company which has low cost power from inexpensive coal as the power purchaser. An operation where the power is wheeled through the local power company and sold at a higher price to some remote company, probably located in a region where little or no coal is mined would be attractive.

These gas turbines, in the range of 500 to 4500 kW, are readily available and find many uses in power production all over the world. They are used to supply power for remote villages, for military operations, for industrial uses, and point on large power grids to where a small amount of power is needed for voltage or phase angle control. Most of them are outgrowths of aircraft jet engine manufacturing and are very reliable. GE produces small gas turbines as an outgrowth of their aircraft engine operations. Solar, Allison, Royals Royce and others produce gas turbines in this size range as a result of their aircraft engine experience.

ABB produces and sells a gas turbine with low NO_x burner where the natural gas fuel is introduced into the combustion air all along the combustor can. This process functions thermally and kinetically, the same as the process patented in US Patent 5,216,876 and would have the same safety and NO_x emissions problems if there were any.

The use of ventilation air with a methane component as the combustion air for a gas turbine will reduce the emissions of coalbed methane. This is an economical and nonintrusive method of reducing greenhouse gases. It is also environmentally helpful since it replaces the use of other fuel which must be produced and burned to produce power.

In terms of the greeenhouse effect, the use of gob gas has the same advantage as using the ventilation air since much of the gob gas is vented to the atmosphere without incineration.

The particular gob gas which was found in the Gateway mine residue is diluted with inerts. This will have a reduced flame temperature and will produce less NO_x. The use of ventilation air also reduces NO_x formation. With these two energy sources we twice reduce methane emissions and we twice reduce NO_x emissions.

The business and development plans incorporate the following :

Revenue

Electric sales to

1. Lazarus Mine
2. SCI
3. West Penn (excess power at destressed price)
4. Heat load to SCI.

Project Development

1. Drill 10 to 20 wells
2. Install two (2) 1.7 MW turbines

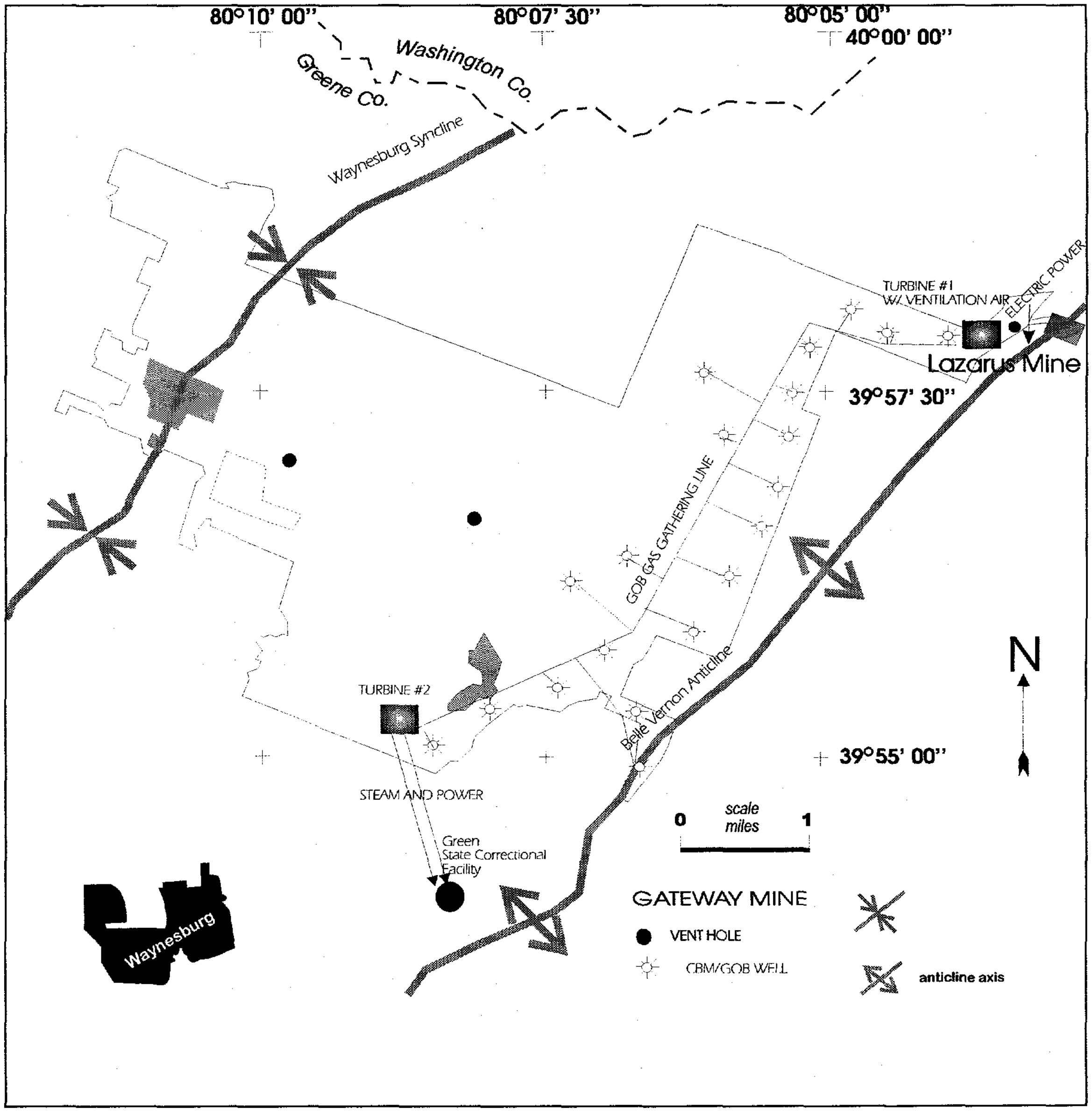
The following Figure No. 42 illustrates the basic development plan. Each turbine would be situated at either end of the Gateway property in proximity to the mine and SCI. Each turbine would supply surplus electricty to West Penn Power's grid at an avoided cost. Ventiallation air would be supplied from the mine for use in the combustion chamber of the turbine #1 and heat would be supplied to SCI in addition to electric power. GOB wells would be drilled as shown to maximize structural postion to gain gravity segregation benifits as gas migrates up the structure from the gob and as desorption occurs from the adjacent coals.

Several economic cases were evaluated. The following Table No. 14 summarizes the Income Statement for the combined GOB well drilling and turbine captial investments and income. This is for the parameters which were discussed above. Table No. 13 summarizes the data input and IRR for the base case which is 23.32%

A. *Risk Analysis*

While overall project economics are acceptable to proceed with project implementation, several downside economic scenarios were evaluated to evaluate the impact of logical consequences (Table No. 15).

Figure 42: Development Map Gateway Mine



The cases evaluated assumed the following:

1. Project Life: 5, 15, and 25 years
2. Power allocation: 20 to 100% at distressed prices to West Penn ($0.017 per kW hr)
3. Number of Wells: 10 and 20
4. Thermal sales: 0 and 136 MCFD
5. Electric sales: $0.017 and $0.04 per kW hr with no inflation

The following Table No. 15 summarizes some of the economic cases which were evaluated.

Table 13: Project Base Case Parameters

GATEWAY PROJECT ECONOMIC RESULTS

COST DATA

NO. WELLS: **10**

COSTS:'$000's	Tangible	Intangible	**Try & Dry-$000's**
Drilling-	$20	$350	**$370**
Completion-	$30	$7	**$37** P&A
Stimulation-	$0	$10	
Total	$50	$367	$407
TOTAL WELL COST	**$417**		
FACILITY-'$000's			
Compression-	**$30**	$6	
Pipeline-	**$40**	$8	
Turbine	**$2,500**	$500	
Saltwater disposal-	**$0**	$0	
Total	$2,570	$514	
Grand Total	**$3,084**		
LEASE/SEISMIC-$000's			
Total	**$0.000**		
WELL OPERATING EXPENSE: -$000/mo			
Direct-			$1.00
Indirect-			$1.00
	Total		$2.00
Success Ratio:			100%
Corporate Tax Rate			20%
Depreciation Expense	1	*1=YES* *0=NO*	

NET PRESENT VALUE TABLE

NPV@0%	$22,317.82
NPV@5%	$9,390.25
NPV@10%	$4,138.20
NPV@20%	$497.41
NPV@25%	($191.24)
NPV@30%	($604.01)
NPV@40%	($1,033.72)
IRR	**23.32%**

Gas Price	**$2.20**
Severance & Adv. Taxes	**0.00%**
Operating Cost Esc. Fac.	**5.00%**

Electric Power Use	**kW- current est.**	**Increase (%)**	**$/kW-hr**
SCI	**1,375**	**10%**	**$0.040**
Mine	**300**	**10%**	**$0.040**
West Penn	1,725	surplus	**$0.017**
	3,400		
Turbine Utilization %	**1.00**		

Heat Load	**MCF/D**	**Increase (%)**	**$/MCF**
SCI	**136**	**10%**	$2.20

Project Life- yrs	**25**
Reserves BCF	9.125
avg $/kW =	0.0350

Power Allocation kW	**% over life**	**Growth %/yr**	**Max kW**
SCI	49%	10.0%	1700
Mine	30%	10.0%	1700
West Penn	21%		surplus

Table 14: Income Statement, Base Case

Year	Electric Production		Heat Load	Electric - $/Kw-hr $000			Revenues	Operating Expenses Direct &	Operating Expenses Turbines	Operating Income	Depreciation	Federal	Cash Flow	
	Turbine #1	Turbine #2	2.20/mcf	SCI	Mine	West Penn	Total Elec. & Heat	Indirect wells	$/kW-hr	Annual	Expense	Tax	*Annual*	*Cum*
	Kw	kW	'000	$0.040	$0.040	$0.017	$000	$000	$000	$000	$000	$000	$000	$000
	10%	10%	10%	1	1	10%		5.00%	$0.005					
0				1	1						$990.71	($198.14)	($3,302.46)	($3,302.46)
1	11.9E+6	2.6E+6	$109	$477	$105	$254.25	$945	$24.00	$148.92	$772.51	$668.06	$55.47	$717.03	($2,585.43)
2	13.1E+6	2.9E+6	$120	$525	$116	$229.56	$990	$24.05	$148.92	$816.89	$511.15	$95.74	$721.15	($1,864.28)
3	14.4E+6	3.2E+6	$132	$577	$127	$202.40	$1,039	$24.10	$148.92	$865.71	$380.21	$131.70	$734.00	($1,130.28)
4	14.7E+6	3.5E+6	$145	$590	$140	$191.71	$1,067	$24.15	$148.92	$893.47	$286.67	$155.97	$737.50	($392.78)
5	14.7E+6	3.8E+6	$160	$590	$154	$185.82	$1,089	$24.20	$148.92	$916.06	$286.67	$160.50	$755.56	$362.78
6	14.7E+6	4.2E+6	$176	$590	$169	$179.35	$1,114	$24.25	$148.92	$940.92	$260.25	$170.77	$770.15	$1,132.93
7	14.7E+6	4.7E+6	$193	$590	$186	$172.23	$1,141	$24.30	$148.92	$968.27	$116.88	$204.92	$763.34	$1,896.28
8	14.7E+6	5.1E+6	$213	$590	$205	$164.40	$1,172	$24.35	$148.92	$998.35	$0.00	$234.32	$764.03	$2,660.30
9	14.7E+6	5.6E+6	$234	$590	$225	$155.78	$1,205	$24.40	$148.92	$1,031.45	$0.00	$240.95	$790.50	$3,450.80
10	14.7E+6	6.2E+6	$258	$590	$248	$146.30	$1,241	$24.45	$148.92	$1,067.87	$0.00	$248.25	$819.62	$4,270.42
11	14.7E+6	6.8E+6	$283	$590	$273	$135.88	$1,281	$24.50	$148.92	$1,107.93	$0.00	$256.27	$851.66	$5,122.08
12	14.7E+6	7.5E+6	$312	$590	$300	$124.41	$1,325	$24.55	$148.92	$1,152.00	$0.00	$265.09	$886.91	$6,008.98
13	14.7E+6	8.2E+6	$343	$590	$330	$111.79	$1,374	$24.60	$148.92	$1,200.48	$0.00	$274.80	$925.68	$6,934.66
14	14.7E+6	9.1E+6	$377	$590	$363	$97.91	$1,427	$24.65	$148.92	$1,253.82	$0.00	$285.48	$968.34	$7,903.01
15	14.7E+6	10.0E+6	$415	$590	$399	$82.65	$1,486	$24.70	$148.92	$1,312.50	$0.00	$297.22	$1,015.28	$8,918.28
16	14.7E+6	11.0E+6	$456	$590	$439	$65.86	$1,551	$24.75	$148.92	$1,377.05	$0.00	$310.14	$1,066.91	$9,985.19
17	14.7E+6	12.1E+6	$502	$590	$483	$47.39	$1,622	$24.80	$148.92	$1,448.06	$0.00	$324.36	$1,123.70	$11,108.89
18	14.7E+6	13.3E+6	$552	$590	$531	$27.07	$1,700	$24.85	$148.92	$1,526.17	$0.00	$339.99	$1,186.19	$12,295.08
19	14.7E+6	14.6E+6	$607	$590	$584	$4.72	$1,786	$24.90	$148.92	$1,612.11	$0.00	$357.19	$1,254.92	$13,550.00
20	14.7E+6	14.9E+6	$668	$590	$596	$0.00	$1,853	$24.95	$148.92	$1,679.28	$0.00	$370.63	$1,308.65	$14,858.64
21	14.7E+6	14.9E+6	$735	$590	$596	$0.00	$1,920	$25.00	$148.92	$1,746.02	$0.00	$383.99	$1,362.03	$16,220.67
22	14.7E+6	14.9E+6	$808	$590	$596	$0.00	$1,993	$25.05	$148.92	$1,819.44	$0.00	$398.68	$1,420.76	$17,641.43
23	14.7E+6	14.9E+6	$889	$590	$596	$0.00	$2,074	$25.10	$148.92	$1,900.20	$0.00	$414.84	$1,485.36	$19,126.79
24	14.7E+6	14.9E+6	$978	$590	$596	$0.00	$2,163	$25.15	$148.92	$1,989.05	$0.00	$432.62	$1,556.43	$20,683.22
25	14.7E+6	14.9E+6	$1,076	$590	$596	$0.00	$2,261	$25.20	$148.92	$2,086.79	$0.00	$452.18	$1,634.61	$22,317.82

Table 15: Risk Analysis

Case No.	1	2	3	4	5	6	7	8	9
#wells	10					20			
Project Life- yrs	25	15	5	25	25	25	15	5	25
IRR	23.32%	21.75 %	1.7%	6.10%	29.7%	20.3%	18.3%	-4.61%	3.8%
NPV@10%	$4,138	$2,405	($547)	($779)	$5,555	$3,566	$1,864	($1,008)	($1,352)
Reserves BCF	9.1	5.47	1.8	9.1	9.1	9.1	5.47	1.8	9.1
avg $/kW hr.	$0.035	$0.033	$0.040	**$0.017**	$0.039	$0.035	$0.033	$0.040	**$0.017**
Power Allocation kW	over life								
SCI	49%	48%	46%	0%	50%	49%	48%	46%	0%
Mine	30%	19%	11%	0%	50%	30%	19%	11%	0%
West Penn	21%	33%	43%	**100%**	0%	21%	33%	43%	**100%**
Heat sales - mcf/d	136	136	136	**0**	136	136	136	136	**0**
$/MCF	$2.20	$2.20	$2.20	**0**	$2.20	$2.20	$2.20	$2.20	**0**
Tax Rate	20%								
Turbine Utilization	1.00								

Table No. 15 summarizes nine (9) of the cases evaluated.

Case No.	Assumptions
1)	Base Case assumes a 10%/ yr. increase in energy at SCI and mine, 25-yr. life, 10 wells
2)	Assumes a 15-year life, same as 1
3)	Assumes a 5-year life, same as 1
4)	25-year life, 100% power sales at distressed prices, no thermal sales
5)	25-year life, 0% sales to West Penn Power, 10 wells
6)	20 wells, same as Case 1
7)	20 wells, same as Case 2
8)	20 wells, same as Case 3
9)	20 wells, same as Case 4

The cash flow table indicates that as power consumption at SCI and the mine increases (all cases expect 4 and 9), the surplus power sold to West Penn decreases over time. Only Case No. 8 indicates a negative IRR. This case assumes 20 wells drilled and a five-year life. Only those cases with 5-year producing lives or 100% power sold at distressed prices indicated a negative NPV@10%.

B. Plan to Build and Operate

At this stage of the project, implementation of project plans are subject to successful negotiations between the lessor (Jessmar), mine (Lazarus), SCI (Prison), West Penn, and CNG (Consolidated Natural Gas). The following table summarizes the anticpated operational plan:

	Functional Responsibility	*Company Name*
1	**Contract Negotiation::**	
	Joint Venture Agreement	CNG/Jessmar
	Power Sales Agreements	CNG
	Ventillation Air	UEDC/ESA
2	**Engineering Design:**	
	Drilling/Gathering system	UEDC
	Turbine	ESA
3	**Operations:**	
	Wells	Jesmar/CNG
	Turbine	CNG
4	**Construction:**	
	Wells	Jessmar
	Turbine	ESA/CNG/Vendor
	Electric Distribution	Vendor
5	**Equpment Sources:**	
	Well Equipment	Local Vendors/Contractors
	Turbine	Vendor

The size and the specifications of the turbine are common delivery items. It is anticipated that the turbine will be bid to engineering specifications once finalized.

VII. Appendix

A. *Conversion Tables*

Table 16: Pressure Equivalents

kilopascals	kg/cm(metric) atmospheres)	lbm/sq. in.	short tons per sq. ft.	atmospheres	columns of mercury at temperate 0 ° C and g=9.80665 m/s² (m)	(in.)	columns of water at temperature 15 ° C and g=9.80665 m/s² (m)	(in.)	(ft.)
1	0.010197	0.14504	0.010443	0.009869	0.007501	0.2953	0.1021	4.018	0.3349
98.066	1	14.22	1.024	0.9678	0.7356	28.96	10.01	394.1	32.84
6.8948	0.07031	1	0.072	0.06805	0.05171	2.036	0.7037	27.70	2.309
95.760	0.9765	13.89	1	0.9451	0.7183	28.82	9.774	384.8	32.07
101.325	1.0332	14.70	1.058	1	0.76	29.92	10.34	407.1	33.93
133.322	1.3595	19.34	1.392	1.316	1	39.37	13.61	535.7	44.64
3.386	0.03453	0.4912	0.03536	0.03342	0.0254	1	0.3456	13.61	1.134
9.798	0.09991	1.421	0.1023	0.09670	0.07349	2.893	1	39.37	3.281
0.2489	0.002538	0.03609	0.002599	0.002456	0.001867	0.0735	0.02540	1	0.08333
2.926	0.03045	0.4331	0.03119	0.02947	0.02240	0.8819	0.3048	12	1

Table 17: Conversions of Lengths

	Inches to Millimeters	Millimeters to Inches	Feet to Meters	Meters to Feet	Yards to Meters	Meters to Yards	Miles to Kilometers	Kilometers to Meters
1	25.40	0.03937	0.3048	3.281	0.9144	1.094	1.609	0.6214
2	50.80	0.07874	0.6096	6.562	1.829	2.187	3.219	1.243
3	76.20	0.1181	0.9144	9.842	2.743	3.281	4.828	1.864
4	101.60	0.1575	1.219	13.12	3.658	4.374	6.437	2.485
5	127.00	0.1968	1.524	16.4	4.572	5.468	8.047	3.107
6	152.40	0.2362	1.829	19.68	5.486	6.562	9.656	3.728
7	177.80	0.2756	2.134	22.97	6.401	7.655	11.27	4.35
8	203.20	0.315	2.438	26.25	7.315	8.749	12.87	4.971
9	228.60	0.3543	2.743	29.53	8.23	9.842	14.48	5.592

Table 18: Conversion of Volumes or Cubic Measures

	cu. in. to cm^3	cm^3 to cu. in.	cu. ft. to m^3	m^3 to cu. ft.	cu. yd. to m^3	m^3 to cu. yd.	gal. to cu. ft	cu. ft to gal.
1	16.39	0.06102	0.02832	35.31	0.7646	1.308	0.1337	7.481
2	32.77	0.1220	0.05663	70.63	1.529	2.616	0.2674	14.96
3	49.16	0.1831	0.08495	105.9	2.294	3.924	0.4010	22.44
4	65.55	0.2441	0.1133	141.3	3.058	5.232	0.5347	29.92
5	81.94	0.3051	0.1416	176.6	3.823	6.54	0.6684	37.40
6	98.32	0.3661	0.1699	211.9	4.587	7.848	0.8021	44.88
7	114.7	0.4272	0.1982	247.2	5.352	9.156	0.9358	52.36
8	131.1	0.4882	0.2265	282.5	6.116	10.46	1.069	59.84
9	147.5	0.5492	0.2549	317.8	6.881	11.77	1.203	67.32

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