DOE/MC/32183 -- 5253
(DE96011310)

Utilization Of Coal Mine Ventilation Exhaust As Combustion Air In Gas-Fired Turbines For Electric And/Or Mechanical Power Generation

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Topical Report
June - August 1995

December 1995

Work Performed Under Contract No.: DE-AC21-95MC32183

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

By
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DOE/MC/32183 -- 5253
(DE96011310)
Distribution Category UC-111

Utilization Of Coal Mine Ventilation Exhaust As Combustion Air In Gas-Fired Turbines For Electric And/Or Mechanical Power Generation

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June - August 1995

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For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
P.O. Box 880
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December 1995

ABSTRACT

Methane emitted during underground coal mining operations is a hazard that is dealt with by diluting the methane with fresh air and exhausting the contaminated air to the atmosphere. Unfortunately this waste stream may contain more than 60% of the methane resource from the coal, and in the atmosphere the methane acts as a greenhouse gas with an effect about 24.5 times greater than CO_2. Though the waste stream is too dilute for normal recovery processes, it can be used as combustion air for a turbine-generator, thereby reducing the turbine fuel requirements while reducing emissions. Preliminary analysis indicates that such a system, built using standard equipment, is economically and environmentally attractive, and has potential for worldwide application.

ACKNOWLEDGEMENTS

The authors wish to acknowledge the support of the U.S. Department of Energy, Morgantown Energy Technology Center (DOE) for their support of the first phase of the project through Contract No. DE-AC21-95MC32183. In particular, the authors appreciate the assistance provided by Mr. Charles Byrer. The authors also acknowledge the contributions made by J.W. Sanders and S.T. Blackburn of Black Warrior Methane Corporation pertaining to methane emissions and methane production operations.

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EXECUTIVE SUMMARY

President Clinton's Climate Change Action Plan, which promotes national energy efficiency and ingenuity as part of the solution to minimize environmental change, has recognized that methane is a significant contributor to global warming. Methane is 24.5 times more effective at producing the *greenhouse effect* than carbon dioxide (EPA-430-F-95-040, 1995). Unfortunately, methane emissions are the inevitable consequence of activities including the underground mining of coal.

Methane liberated in coal mines is a safety hazard because it is explosive at low concentrations (5 to 15%) in air. To manage methane, underground mines are ventilated with large quantities of air, and in some cases the gas is also drained with gob wells and predrained with vertical, and horizontal wells. The ventilation air is used to dilute methane emissions to levels well below the explosive limit, and the dilute stream is discharged to the atmosphere as waste. This waste stream may contain as much as 60% of the total gas energy that was originally in the coal, even with drainage and predrainage of the coalbed. The volume of the waste stream, the high electric power demands of the mine, and greenhouse effect of the methane provide a strong incentive for converting the waste-methane chemical energy to the electrical or mechanical equivalent. However, ventilation air exits the mine at concentrations of about 0.5% methane, a concentration too low for direct combustion or economic extraction.

In this Phase-1 report a method is examined for using this highly diluted fuel. Specifically, technology is addressed for utilizing ventilation air with a content of about 0.5% methane by mixing it with high-quality gas from gob wells or pre-mining drainage wells (80% to 98% methane) to produce a combustible mixture, and using that combustible mixture to fire a turbine for electrical power generation. In the first test of this technology, the generated electric power will be used to drive the ventilation fans.

The economic assessment, based on installation of a Solar Turbines, Inc. Centaur Model 40 at the Jim Walter Resources No. 5 Mine, shows that the proposed project is economically attractive, even without considering the emissions benefits. This unit would produce enough power to drive a single fan, provide a profitable rate of return, and produce a 2% reduction in emissions from a single fan.

The initial market study indicates that with the methods outlined in this report, there is the potential to generate 706 to 816 MW of power from mine gas in the U.S. Worldwide, if only 10% of the estimated mine emissions can be used for power generation, this technology has potential for generation of 1,689 to 1,953 MW of capacity, with a commensurate reduction in emissions.

1.0 Introduction and Background

Historically, methane liberated in coal mines has been viewed as a safety hazard because of its explosiveness at low concentrations (5 to 15%) in air. To manage methane, underground mines have been and still are ventilated with large quantities of air. This ventilation air is used to dilute the methane to levels well below the explosive limit, and the dilute stream is discharged to the atmosphere as waste. Since the ventilation flow rates are high, the dilute methane-and-air mixture may still contain as much as 60% of the total gas energy that was present in the coal before mining operations. These ventilation operations are expensive because of the high energy levels required by large fans. The substantial electrical power consumption of a mine provides a strong incentive for converting the waste-methane chemical energy to the electrical equivalent. Aside from the energy and economic-related advantages, significant environmental benefits could be realized concurrently by reducing methane emissions to the atmosphere, since methane has been identified as a gas which contributes to the *greenhouse effect*.

In some coal seams, coalbed methane can be recovered prior to mining with predrainage by vertical and/or horizontal wells. This provides a source of high-quality methane. Methane can also be extracted from mined areas with gob wells. Despite the partial extraction of methane by wells prior to and during mining, considerable levels of methane are still released into the ventilation stream during the mining process. This portion of the methane exits the mine with the ventilation air at concentrations in the vicinity of 0.5% for the Blue Creek seam in Alabama. In the Jim Walter Mines in Alabama, high-quality methane is produced and sold from both pre-mine drainage wells and gob wells. However, because the methane concentrations in the ventilation air are so low, that resource is not currently used.

In this Phase-1 report a method is examined for using this highly diluted fuel. Specifically, technology is addressed for utilizing ventilation air with a content of about 0.5% methane by mixing it with high-quality gas from gob wells or pre-mining drainage wells (80% to 98% methane) to produce a combustible mixture, and using that combustible mixture to fire a turbine for electrical power generation. In the first test of this technology, the generated electric power will be used to drive the ventilation fans. The net effect will be a reduction in the operating cost of the fans, coupled with a simultaneous reduction in emissions.

The proposed technology has worldwide applications since global methane emissions to the atmosphere from coal mining have been estimated to be 70 million m^3/day (Kruger, 1991). Nine countries emit 90% of the methane from coal mining. Of those, the largest percentage is from the Peoples Republic of China (PRC) with 35%. The Commonwealth of Independent States (CIS), also referred to as the former Soviet Union, contributes 20%, and the United States emits 14%. The remaining percentage of liberations from coal mines occur in Germany, South Africa, India, Poland, United Kingdom, Australia, and Czechoslovakia in roughly equal proportions (Kruger, 1993). China, the United States, and the former Soviet Union accounted for about 56% of total coal production in the world in 1990. China was the leading producer with 1.2 billion short tons (EIA, 1992).

Coal is mined by surface and underground methods. Between the two methods, underground mining is responsible for the vast majority of methane emissions to the atmosphere. The percentage of mining by underground methods in the PRC is greater than 95%. In the CIS, underground coal mining accounts for 56% of the coal production. The percentage of coal mined underground for other major coal-producing countries are: U.S. (41%), Poland (73%), South Africa (64%), India (46%), Germany (18%), U.K. (84%), Australia (25%), Czechoslovakia (21%) (Kruger, 1993). China, the U.S., Australia, and South Africa are expected to expand coal production between now and 2010. The coal production in Europe, including Poland, is expected to decline as countries restructure their coal industries and eliminate non-competitive coal production. The largest production cutbacks are expected in Great Britain, with the privatization of the electric power and coal industries (EIA, 1992).

China is the world's largest emitter of methane from coal mining. Its estimated coal mining emissions of 12.4 to 19.2 billion m^3 are about one-third of the world's total emissions. Efforts have been made by China's coal industry to extract methane from coal mines for safety purposes. However, annual production of captured coalbed methane throughout the country was merely 434 million m^3 in 1990. Obviously, this is a very low level of methane drainage relative to the high coal yield and gas emissions.

President Clinton's Climate Change Action Plan, which promotes national energy efficiency and ingenuity as part of the solution to minimize environmental change, has recognized that methane is a significant contributor to global warming. Methane is 24.5 times more effective at producing the *greenhouse effect* than carbon dioxide (EPA-430-F-95-040, 1995). Therefore, methane utilization at the mine mouth will provide tremendous economic benefits to the mine owners and their local communities, while reducing global warming.

2.0 Phase I — Task 1, Determination of Mine Gas Potential

2.1 Objective

The objective of Task 1, Phase 1, is to determine the methane gas potential from the selected mine site. This will include the methane gas in the ventilation stream, as well as the gas production from gob wells and pre-mine drainage wells (vertical and horizontal).

2.2 Mine Site

2.2.1 Project Location

The site selected for the potential demonstration project is at the Jim Walter Resources Blue Creek No. 5 Mine (JWR No. 5), located in north-central Alabama within eastern Tuscaloosa County, Figure 1. The JWR No. 5 mine is part of a four-mine underground complex within eastern Tuscaloosa county and western Jefferson county operated by Jim Walter Resources, Inc. Depths of operations in these four mines (JWR No. 3, No. 4, No. 5, and No. 7) range from 1,300 to 2,100 feet, making these mines some of the deepest operating coal mines in the U.S. Adjacent to these mines are other underground coal mines operated by USS Mining Company (Oak Grove Mine) and Drummond Coal Company (Shoal Creek Mine).

The mine site is easily accessible via state highway Route 216 and is 25 miles from the Adger interchange on U.S. Interstate Highway I-59/20. In addition to the well-developed county road system in the area, the mining operations maintain extensive all-weather roads for access to ventilation shafts, mine degasification gob and vertical wells, and other facilities throughout the surface area of the mine.

Topographically, the area is the dissected Appalachian plateau province area with an average vertical relief of 50 feet. A more pronounced topographic relief (up to 200 feet) can occur in the vicinity of stream valleys, such as the Davis Creek valley which is located east and north of the JWR No. 5 mine area. The closest major population centers are Birmingham, Alabama (50 miles to the northeast on I-59/20) and Tuscaloosa, Alabama (25 miles to the west-southwest on I-59/20), although numerous towns and villages are present within the mining area. Surface use in the area is composed of timber cutting, surface facilities for underground mining operations, surface (strip) mining, and limited agriculture.

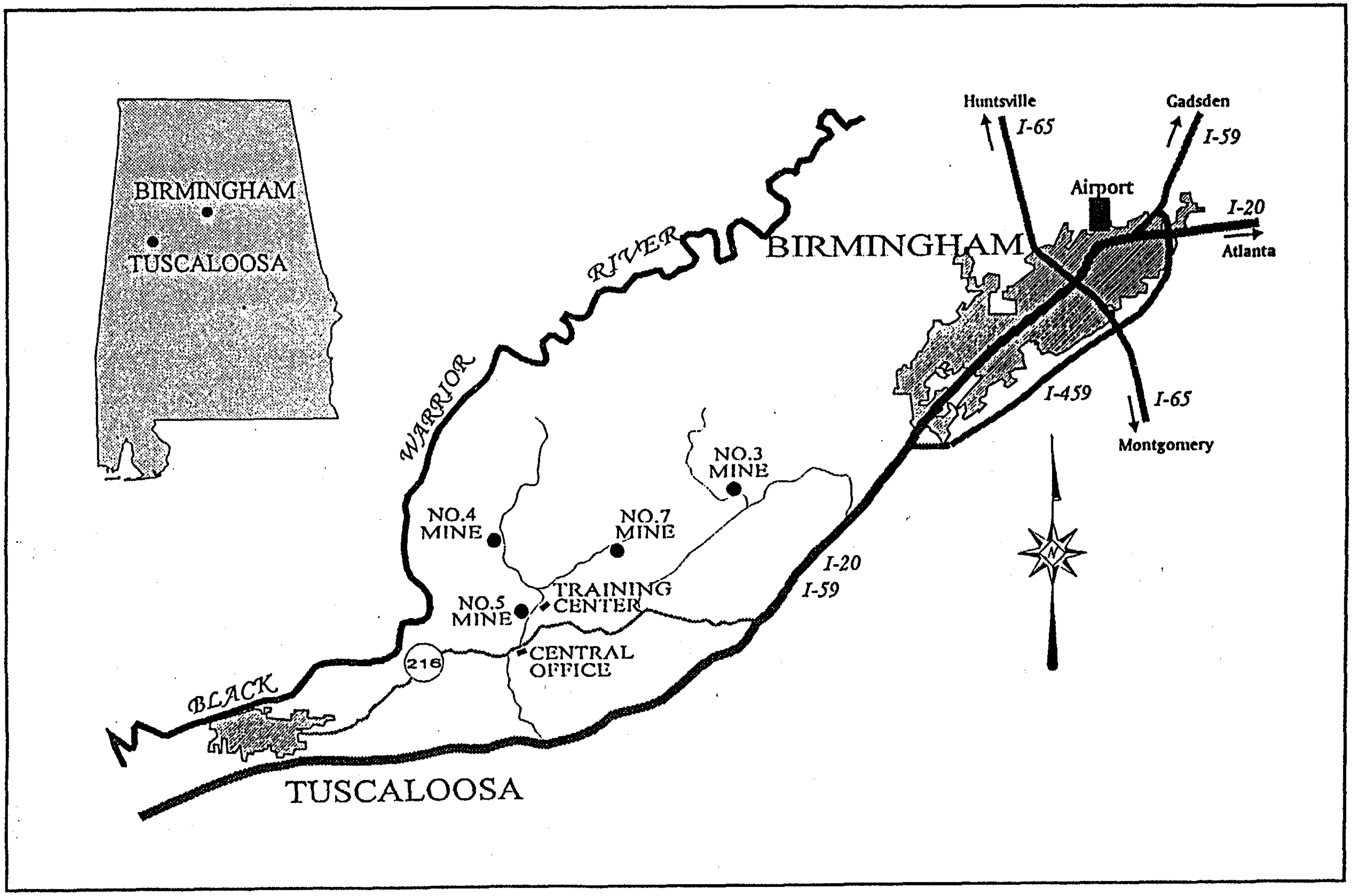

Figure 1. Location of Jim Walter Resources' facilities.

Justification for the selected site is supported by Table 1 (EPA-430-R-94-012, September 1994) which compares methane emissions from Alabama coal mines. Table 1 indicates that in 1990, Mine 5 emitted about 29.8 mmcf/d of methane, of which 10.4 mmcf/d was captured and sold, while the remaining 19.4 mmcf/d was emitted to the atmosphere with the ventilation air. These emissions (including the captured methane) are more than sufficient for the proposed gas turbine project (about 1 million cubic feet per day (mmcf/d) is required).

2.2.2 Geologic Setting of the JWR No. 5 Mine

The JWR No. 5 mine is located within and along the eastern edge of the Warrior basin. The Warrior basin is the southernmost of a series of Pennsylvanian-age basins of the Appalachian plateau in the eastern U.S. The basin is principally a triangular wedge of sedimentary rock that is structurally bounded on the east and southeast by steeply dipping strata of the Appalachian orogenic belt and on the southwest by the deeply buried Ouachita structural trend, Figure 2. The northern edge of the basin is stratigraphically defined by the updip limit of Pennsylvanian-age rocks (McFall, Wicks, and Kuuskraa, 1986).

The easternmost part of the Warrior basin (the area of the project site) is characterized as a structurally complex foreland basin (Pashin, 1991). The eastern margin of the basin is a large thrust structure formed during the Alleghenian orogeny. While extensive folding and faulting of the early Paleozoic strata is more commonly associated with this compressional orogenic event, the eastern Warrior basin is characterized by more broad and low amplitude folds and little evidence of thrust faulting. However, numerous enechelon normal faults are present within this area of the basin, possibly due to tensional pull-apart structures formed during basal decollement in the Alleghenian orogeny (Pashin, 1995), Figure 3.

Within the specific area of the JWR No. 5 mine, the geologic structure consists of a series of northwest-southeast trending normal faults with stratigraphic throws ranging from a few feet to over 100 feet, Figure 4. The primary target coal seam (Mary Lee/Blue Creek) dips gently to the west across most of the mine area. However, along the southeastern edge of the mine area the structure is dominated by the main Appalachian overthrust, such that the dip of the strata changes rapidly from near horizontal to near vertical. This highly deformed and folded area is the limit of underground mining operations at the JWR No. 5 mine.

The coal-bearing strata of the Warrior basin occur in the Lower Pennsylvanian Pottsville formation and consist primarily of sandstone, siltstone, and shale with minor amounts of coal. Repeated sedimentary cycles, each of which correspond to a major coal group, are common throughout the basin (Boyer, Popovich, Schraufnagel, Dobscha, Schwerer and Militzer, 1986).

Table 1 - Methane Emissions from Alabama Mines.

Mine	Company	1992 Coal Production (mm tons)	1990 Methane Emissions[1]: From Ventilation Systems (mmcf/d)	From Degas Systems (mmcf/d)	Total Emissions (mmcf/d)	Emissions per ton Coal (cf/ton)
Utilizing Mines:[2]						
Blue Creek No. 3	Jim Walter Resources	1.8	15.2	8.2	23.4	3617
Blue Creek No. 4	Jim Walter Resources	2.4	11.9	6.4	18.3	2645
Blue Creek No. 5	Jim Walter Resources	1.5	19.4	10.4	29.8	7760
Blue Creek No. 7	Jim Walter Resources	2.1	16.5	8.9	25.4	3489
Oak Grove	U.S. Steel	2.3	11.5	6.2	17.7	3673
Total		10.1	74.5	40.1	114.6	
Operating Mines:						
Chetopa	Drummond	0.8	1.2	0.0	1.2	655
Mary Lee No. 1	Drummond	1.8	2.1	0.0	2.1	636
North River No. 1	Pittsburgh & Midway	1.9	2.0	0.0	2.0	367
Total		4.5	5.3	0.0	5.3	
TOTAL		14.6	79.8	40.1	119.9	
New Mine:						
Shoal Creek	Drummond					

1 Explanation of how methane emissions were estimated is discussed in the "Instructions" section.

2 Recovery and utilization projects have already been developed at these mines. Methane released from degasification systems was recovered for sale as natural gas.

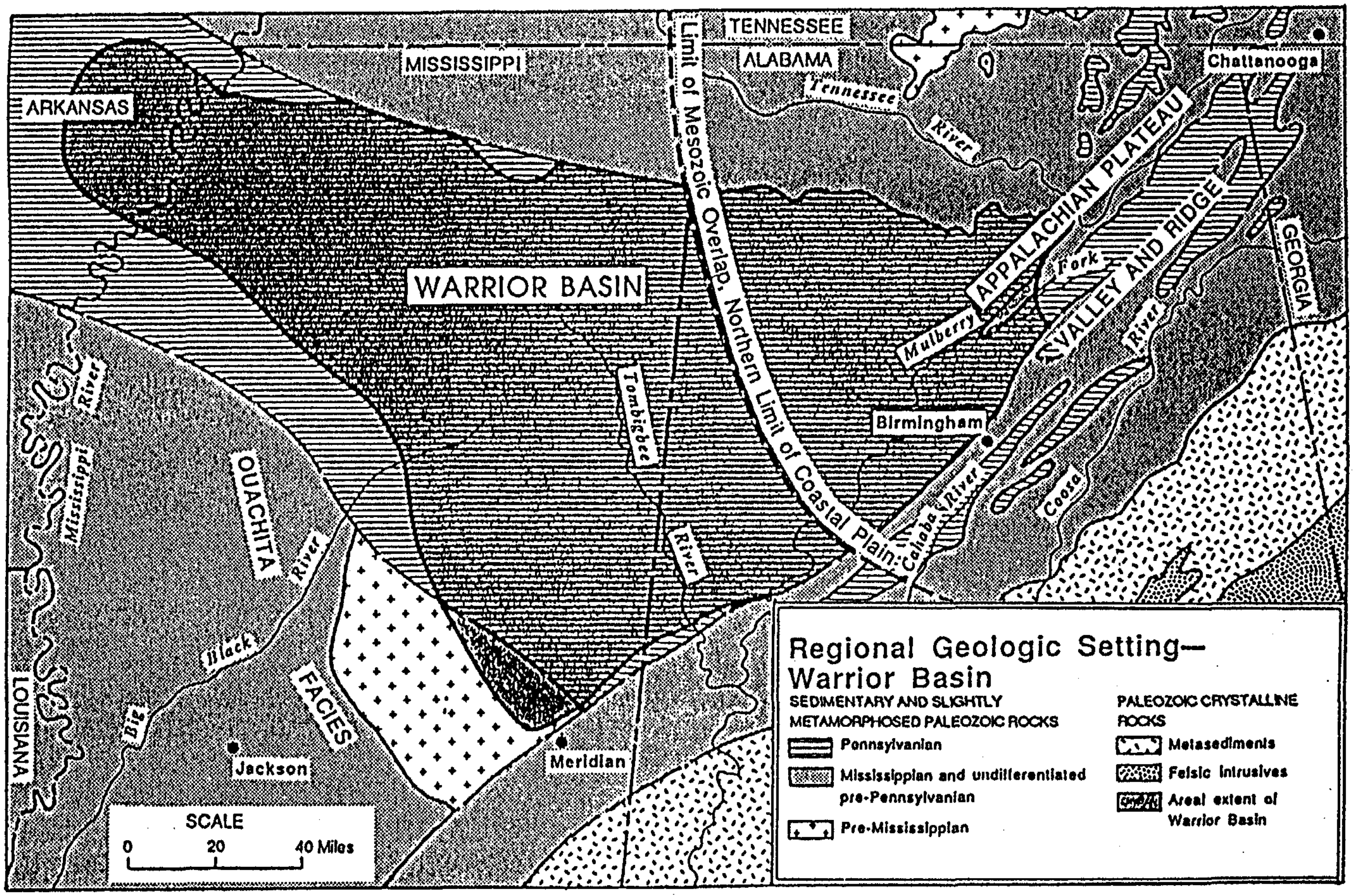

Figure 2. Geological setting of the Warrior Basin.

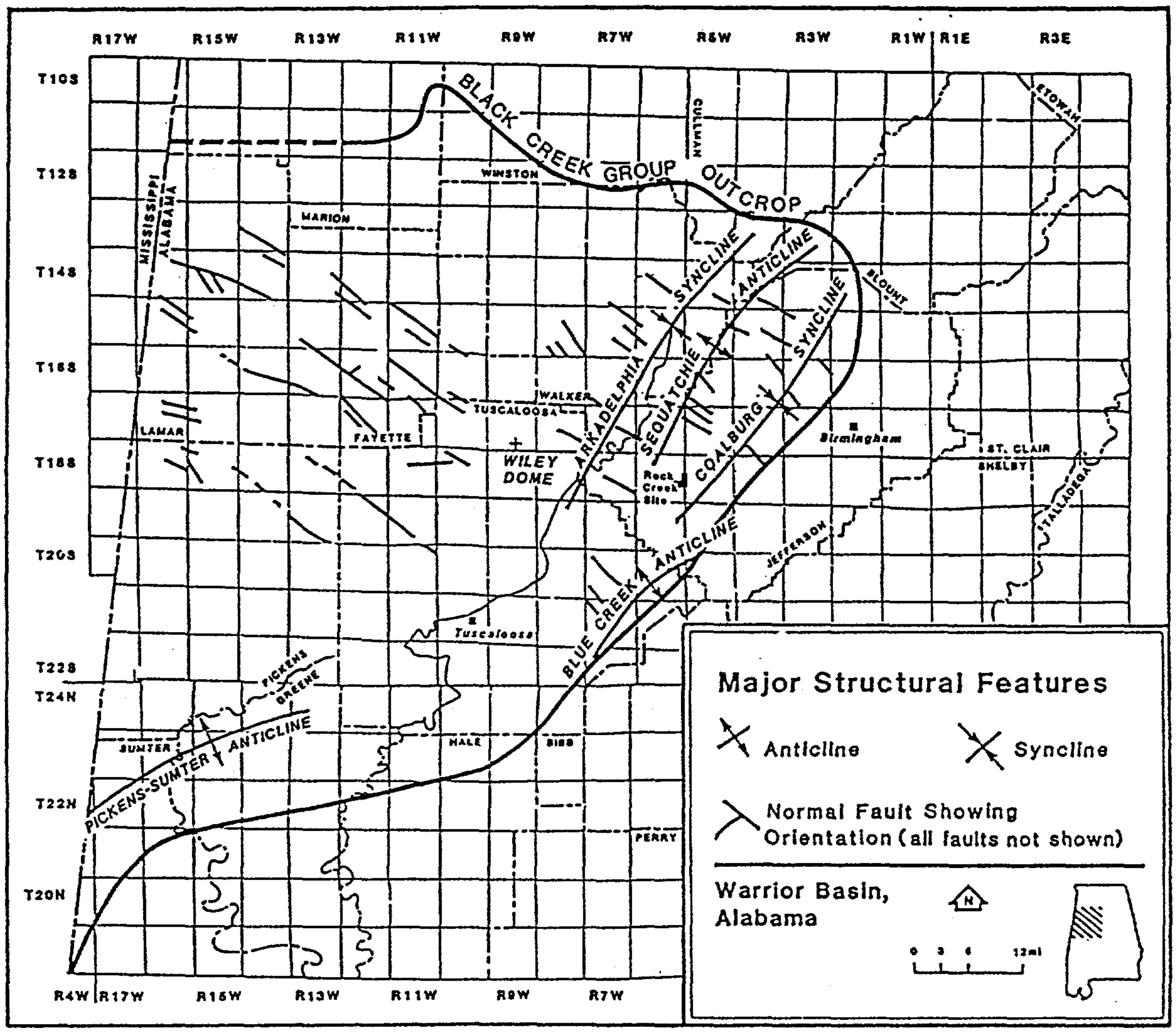

Figure 3. Structural features of the Warrior Basin.

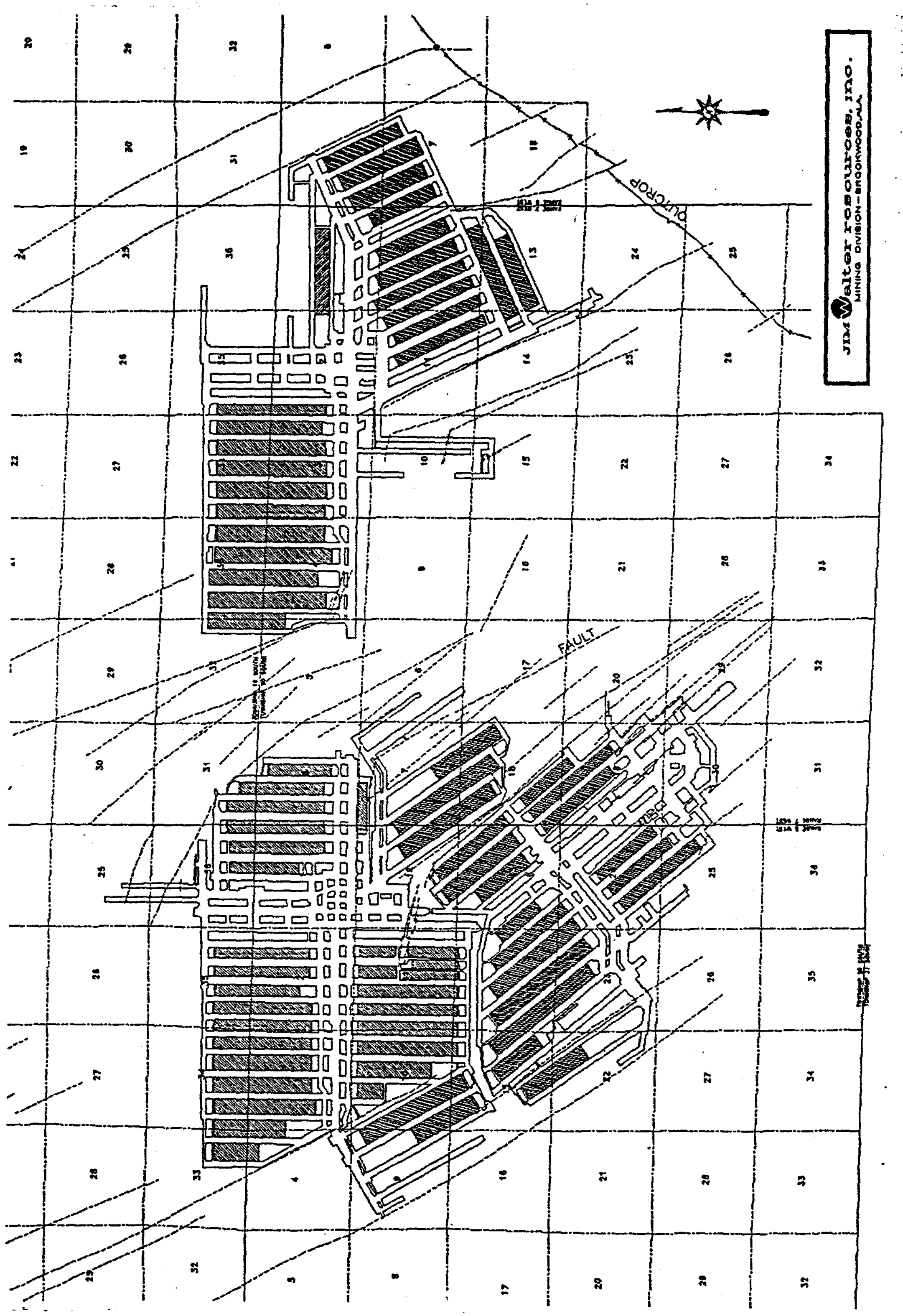

Figure 4. Mine map showing geological faults.

Eight coal groups are present within the eastern portion of the Warrior basin (from oldest to youngest): 1) Black Creek; 2) Mary Lee; 3) Gillespy/Curry; 4) Pratt; 5) Cobb; 6) Gwin; 7) Utley; and 8) Brookwood (McFall, Wicks, and Kuuskraa, 1986; Pashin, 1991; and Pashin, 1995), Figure 5. Coal groups (which contain the subject coal seams) generally cap the regressive, coarsening-upward sedimentary cycles. The cycles have as much as 350 feet of marine mudstone at the base and typically coarsen upward into sandstone. At the top of each cycle is the interbedded mudstone, sandstone, underclay, and coal that makes up a coal group (Pashin, Groshong, and Wang, 1995). Within the Warrior basin the Mary Lee and Blue Creek coal seams of the Mary Lee group are the primary target zones for coal mining. Locally, the Pratt seams within the Pratt Group are also underground mining targets.

The JWR No. 5 mining operation primarily targets the Blue Creek coal seam. In addition, the overlying Mary Lee seam is also mined if the rock parting between the two coal seams is too thin and cannot be supported by normal roof control techniques. Coal seams of the other seven coal groups discussed above are present within the mine area, as shown in the typical well stratigraphic section for the mine area, Figure 6. However, individual coal seams within these groups often are not continuous across the mine area.

2.2.3 Mining Operations at the JWR No. 5 Mine

The mining operations at the JWR No. 5 mine target the Mary Lee/Blue Creek coal seam at a depth ranging from 1,900 to 2,100 feet. Continuous mining sections (there are 3 sections operating at the JWR No. 5 mine) develop the mine main entries and sub-main entries and the headgate/tailgate/bleeder entries surrounding the planned longwall panels. The mine mains and sub-mains typically consist of 4 to 6 entries with yield and barrier pillar support systems employed. The mains and sub-mains are designed to effectively create a long-term access/egress route within the mine for ventilation, personnel, and produced coal movement.

Once the continuous miner sections have developed the headgate/tailgate/bleeder entries surrounding planned longwall panels, longwall mining equipment utilizing ranging-arm rotating drum shearers, armored drag-chain face conveyors, and four leg-type shield units for safe roof support are installed for longwall mining operations. Longwall panels originally were 600 to 750 feet in width but current operations utilize panel widths of 850 to 950 feet. Panel lengths are dependent upon local mining conditions, especially the presence of the numerous high-angle normal faults that are present within the mining area. Typical panel lengths of 5,500 to 6,500 feet are currently employed by the mining operations.

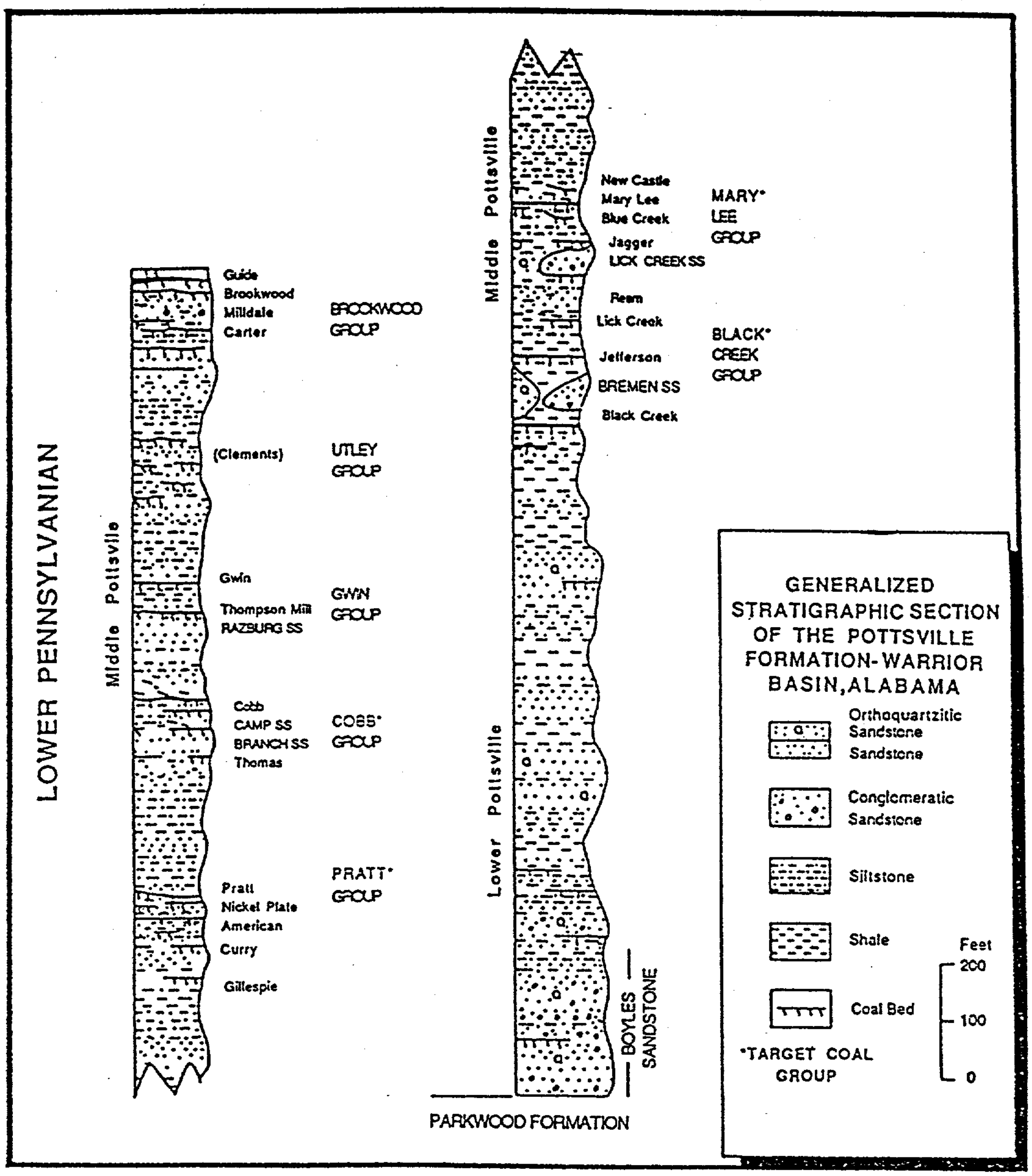

Figure 5. Stratigraphic section for the Warrior Basin.

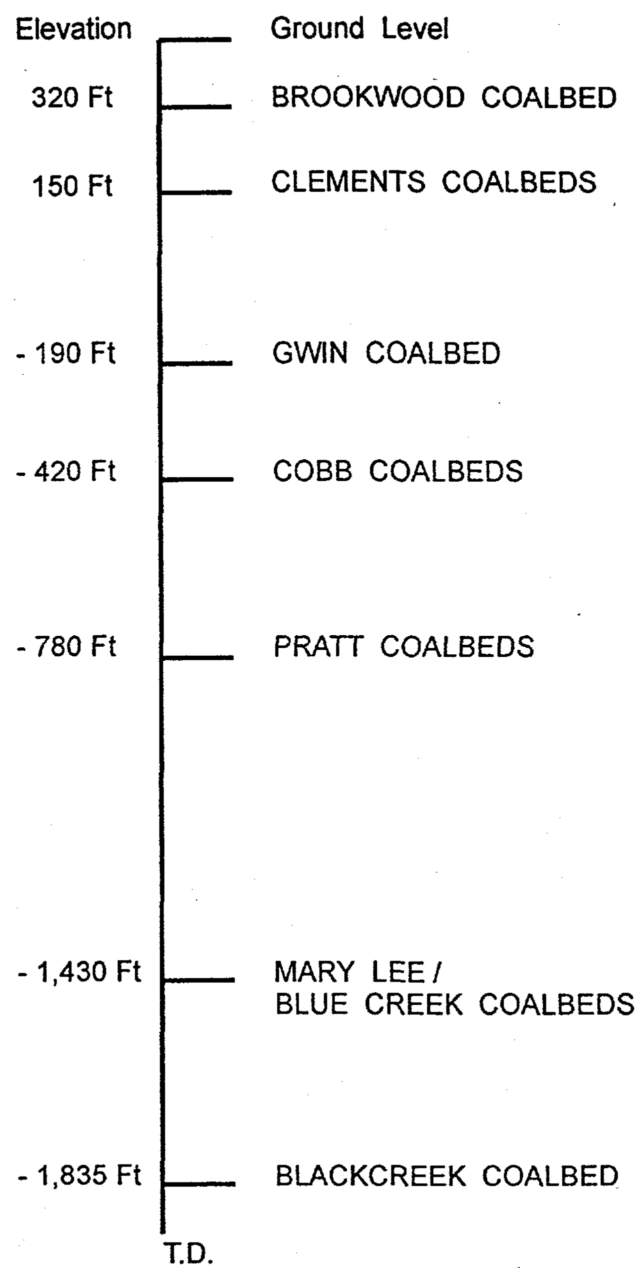

Figure 6. General stratigraphic section of Mine No. 5.

Coal mined from the continuous and longwall operations is transported from the working face area via shuttle-car haulage and conveyor systems to underground storage bunkers located near the bottom of the production shafts. Balanced hoisting skips transport the coal from the temporary storage bunkers to the surface, transporting 20 to 25 tons of mined coal per lift (Mills and Stevenson, 1991).

The active portion of Mine No. 5 is illustrated in the mine map of Figure 7. The blackened areas of the map indicate the gob areas of the mined-out longwall panels. The two adjacent panels to the left show longwall-mining projections through 1997. During 1997 the longwall is expected to be moved to the eastern portion of the mine. Figure 8 shows longwall projections to the year 2000.

Three main fans are used for ventilating the mine, and are located within the circles drawn on the mine map of Figure 7. Each fan has a 12-ft diameter and is powered by a 3500-hp electric motor. Two fans, connected in parallel, are located at the northern exhaust-shaft location, with one fan at the southern exhaust shaft. Figure 8 shows a circle enclosing the future location of another main fan that will be installed when mining progresses to the east side of the mine. Once the mining activity moves to the eastern section and the new fan is brought on-line, the northern section of the mine may be sealed, the fans at one or two exhaust shafts may then be dismantled and moved to other future locations.

2.3 Captured Emissions

Methane that is captured and sold from the JWR No. 5 mine is produced from vertical pre-mine drainage wells, in-mine horizontal drainage wells, and gob wells.

2.3.1 Vertical Pre-Mine Drainage Wells

JWR, along with other mining companies in the Warrior and Appalachian basins, utilize vertical wells drilled into the unmined coal areas as an effective means of removing the methane from the coal prior to its mining. This type of well, drilled and completed in a method similar to conventional natural gas wells, is the primary basis for the large U.S. coalbed methane industry, in which over 6,700 wells were producing 2.2 billion cubic feet of methane per day at the end of 1994.

Vertical wells at the JWR mines in the Warrior basin initially only targeted the seam that was being mined - the Mary Lee/Blue Creek. However, with improved drilling and completion techniques, current wells target all primary coal gas horizons in the well, including the coal seams

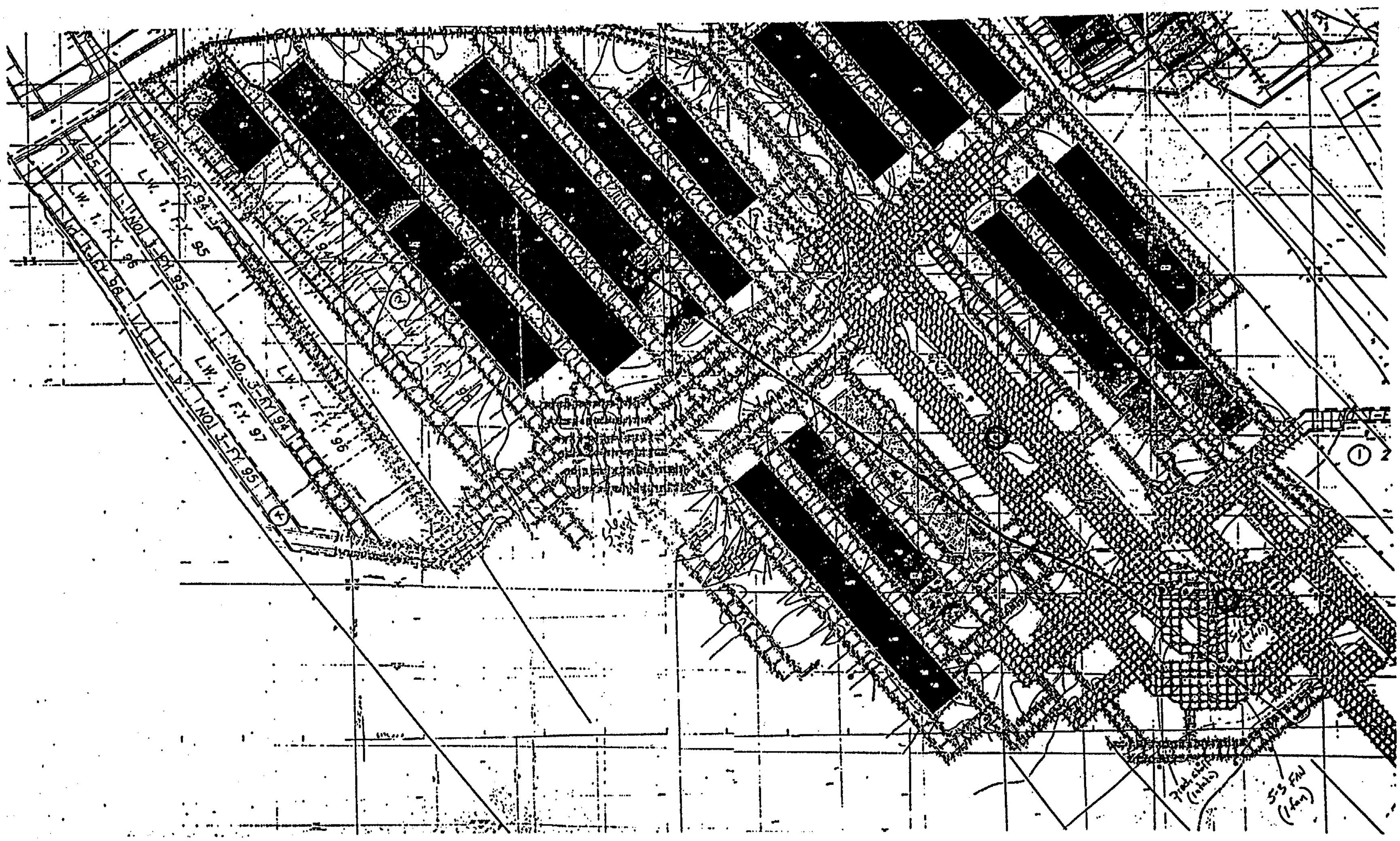

Figure 7. The active working area of Jim Walter Resources Mine No. 5.

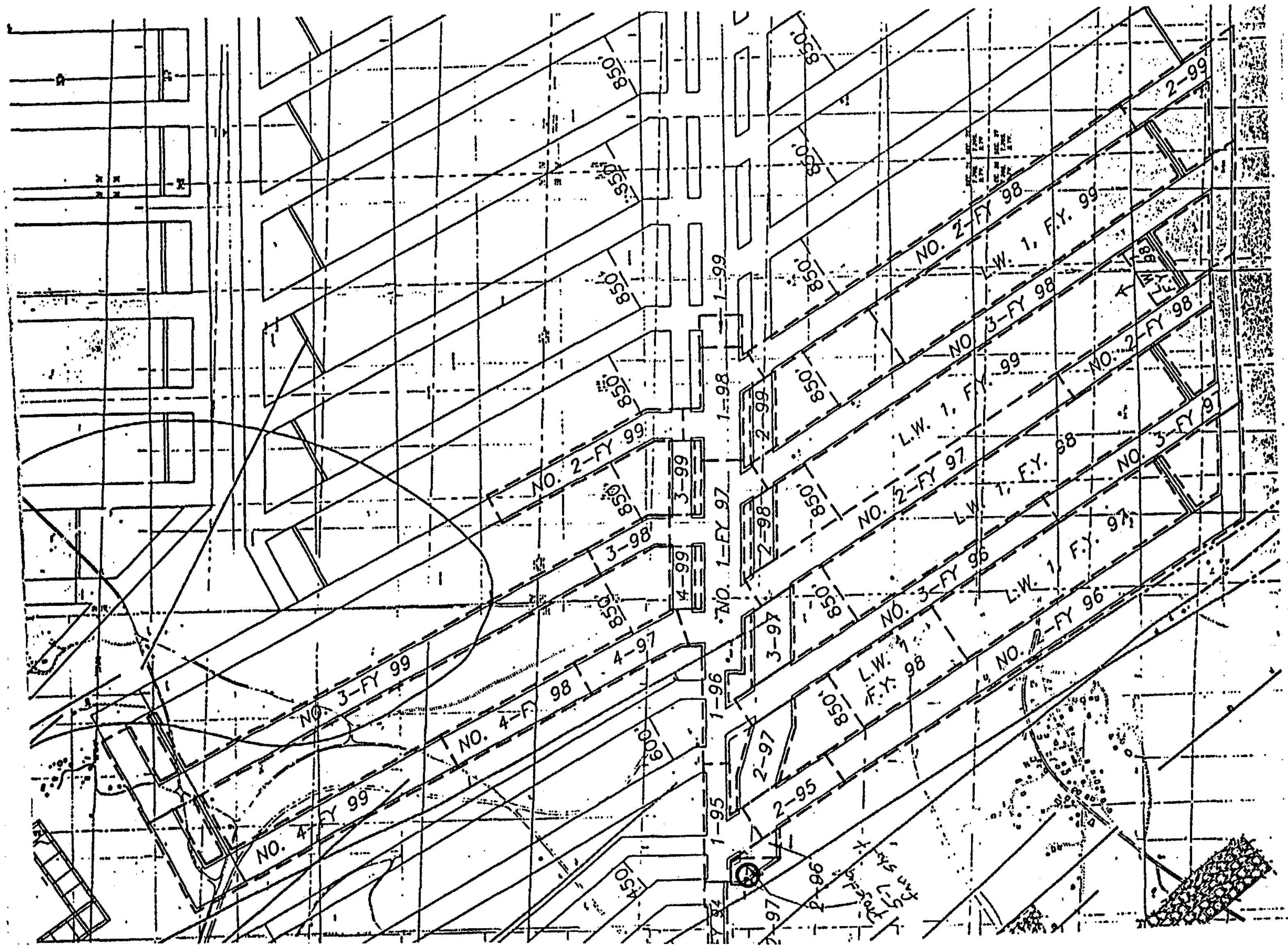

Figure 8. Projected mining area of Jim Walter Resources Mine No. 5.

of the Black Creek, Mary Lee, Gillespie/Curry, Pratt, and Cobb coal groups. Figure 9 illustrates a typical vertical well completed into one coal zone. In this figure, water that is co-produced with the coalbed methane is pumped from the well through a central tubing string, whereas the gas flows naturally in the annular area between the tubing and the well casing. To enhance the gas flow from the typically lower permeability coal formations, the coal seams are hydraulically stimulated. Generally, three to four stimulation treatments are performed in each well.

One of the advantages of vertical, fractured wells is that the gas produced is unaffected by the mining operations. The gas quality is that found naturally in the coal seam and in the JWR mine areas. The gas is principally methane (98 to 99%) with minor amounts of nitrogen, carbon dioxide, and other hydrocarbons.

As shown in Figure 10, daily production from the vertical, fractured wells in the JWR mining area has slowly increased during the past three years. Increased emphasis by the mining company on vertical well drainage and improved completion practices has led to an increase use of this type of methane recovery. Current production from the 110 vertical wells in the JWR mining area averaged 11 million cubic feet per day during June 1995, for an average per well daily production of 100,000 cubic feet. It should be noted, however, that the average daily rate includes new wells still undergoing dewatering (gas production is increasing), wells that are at their peak production, and older wells that have begun their production decline phase.

Figure 11 clearly demonstrates the impact of improved completion practices on vertical well productivity at the JWR mines. The three new wells produce at rates 3 to 6 times those of the older wells, although some of this increase is due to the fact that the older wells may have already begun their production decline phase. Nonetheless, vertical well production and degasification is an effective means of lowering the gas content of the mined coal and the coal that will become part of the future gob area. It is anticipated that, given enough production time (5 to 10 years), the vertical wells will be able to lower the methane content of the produced coal seams by as much as 50%.

2.3.2 Horizontal Wells

Horizontal wells have been used in the JWR mines since the late 1970s as an effective means of removing methane from unmined longwall panels. The wells are drilled from the active mine workings (the longwall panel headgate road) across the width of the panel. Typical depth is 100 feet less than the longwall panel width. These wells are connected to an underground piping system that transports the methane through the mine to a collection point where a vertical well then transports the methane to the surface, Figure 12.

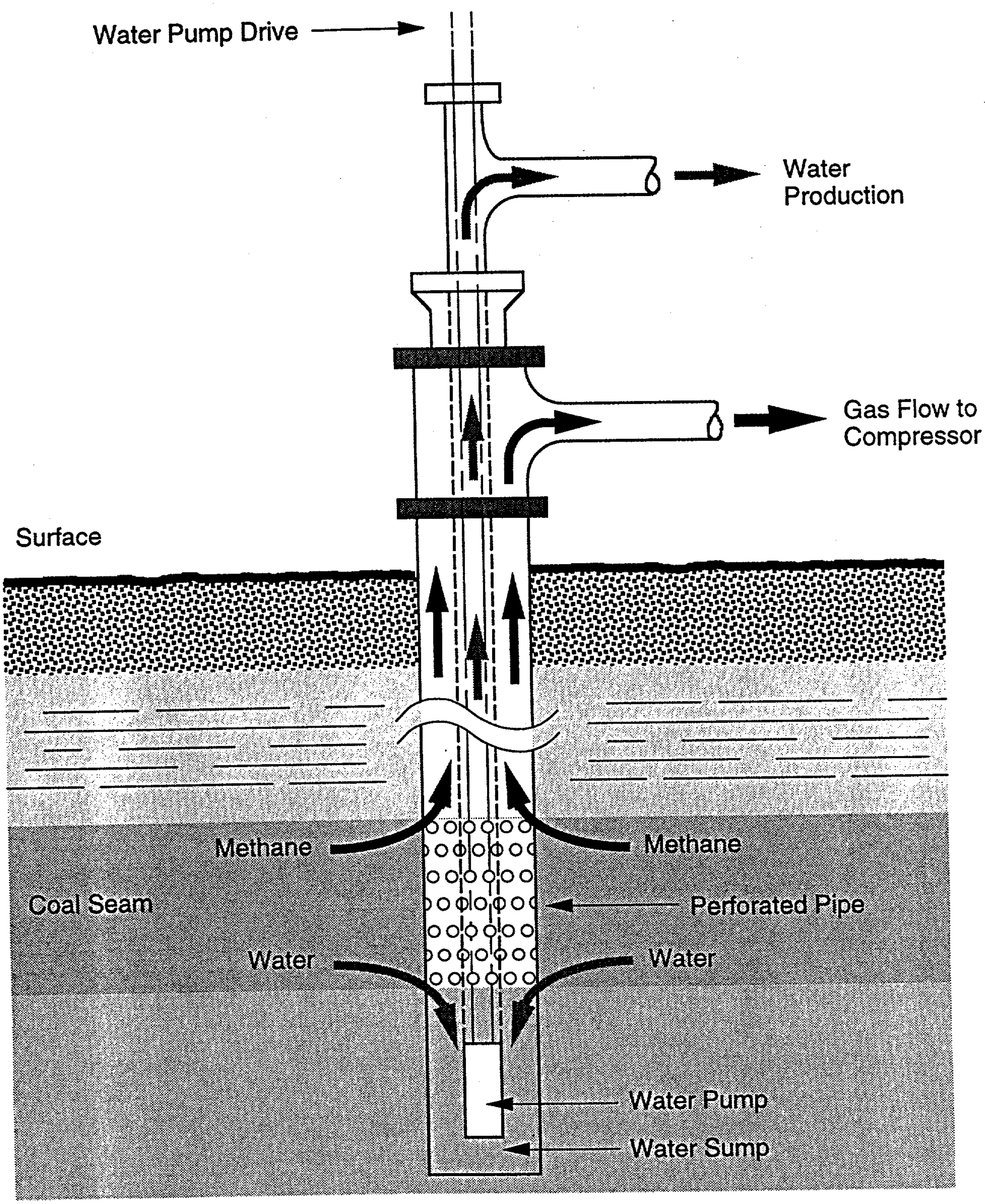

Figure 9. Gas production from a vertical well.

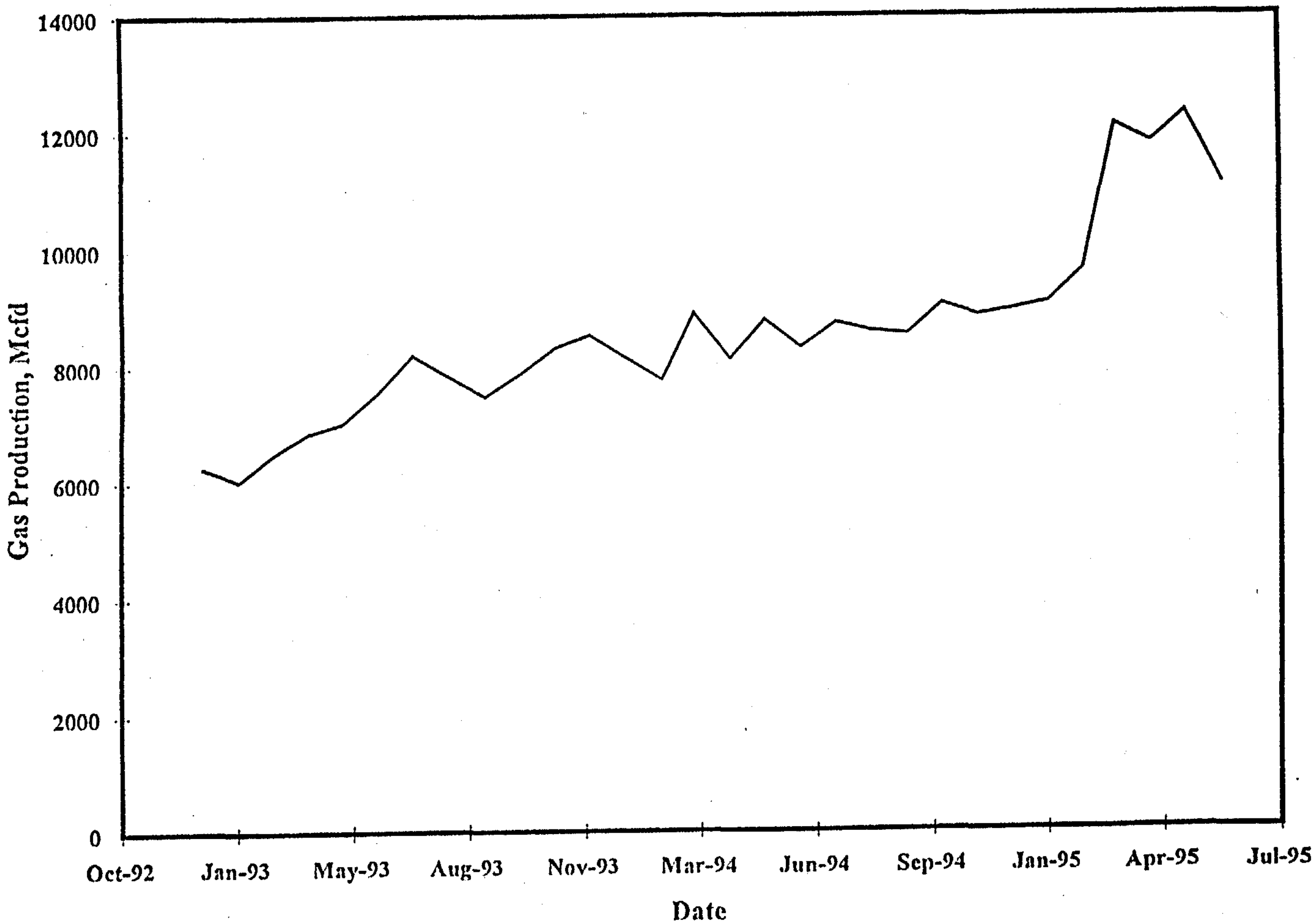

Figure 10. Vertical well production history (1993-1995).

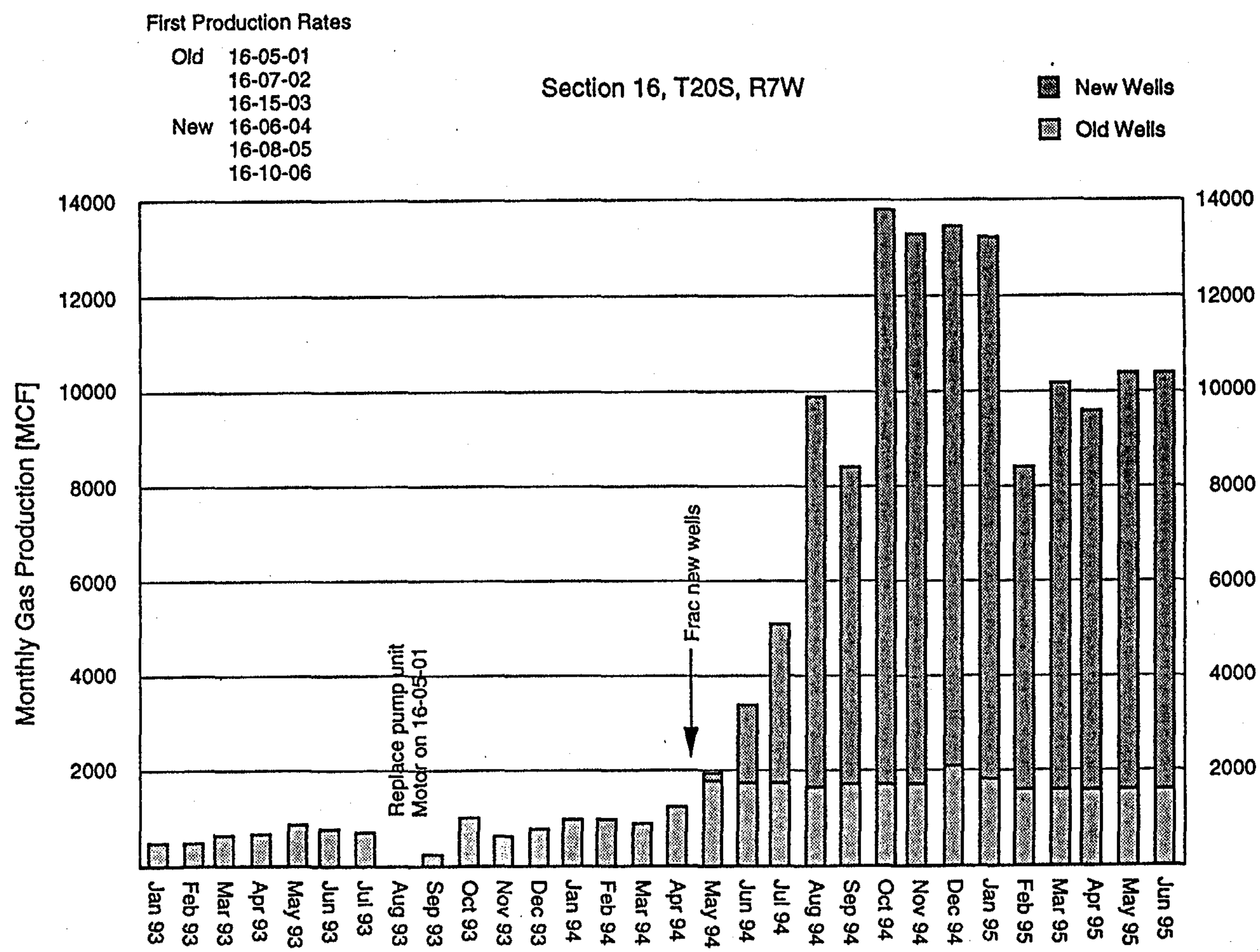

Figure 11. Monthly production rates from vertical degas wells.

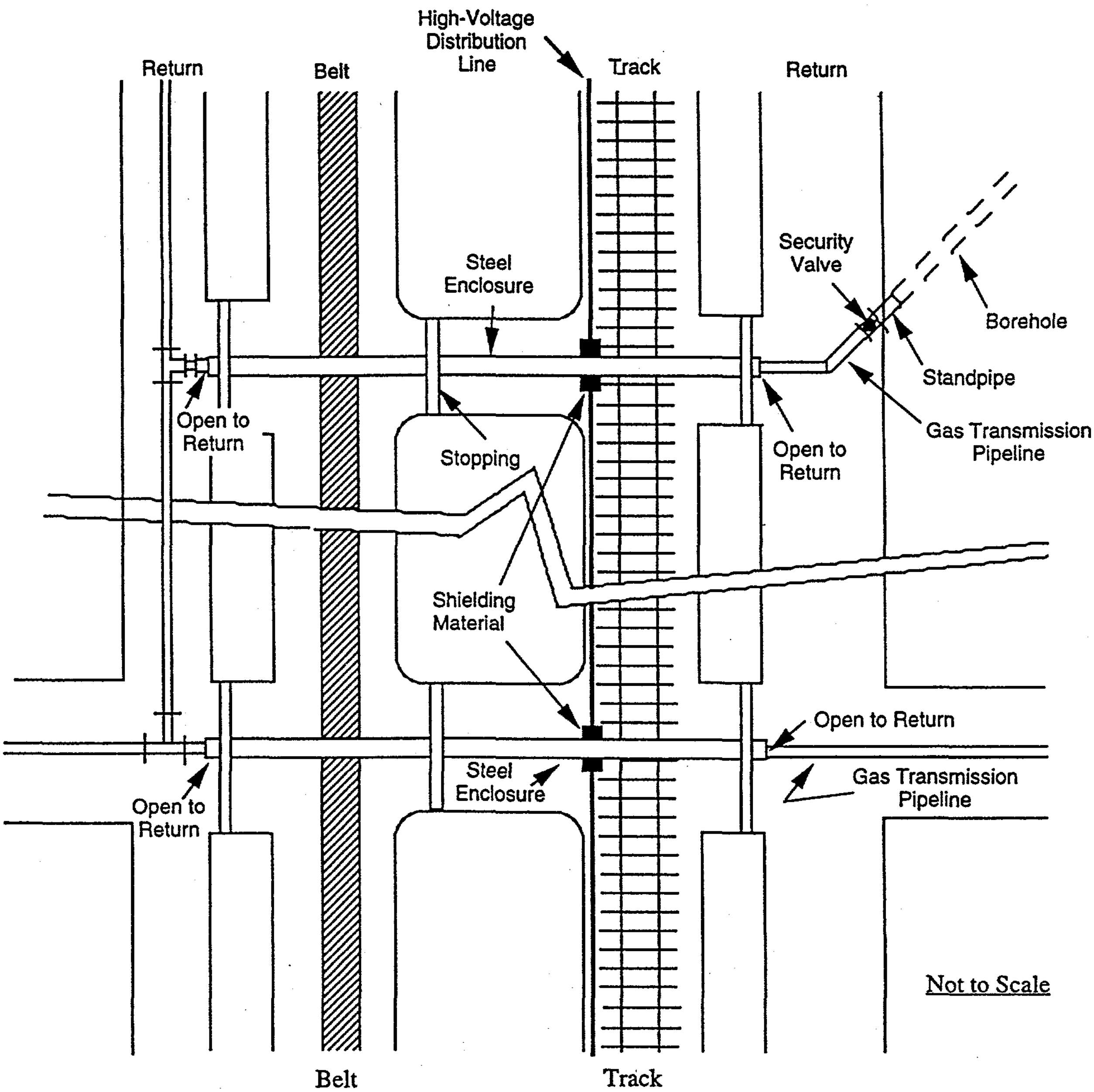

Figure 12. Horizontal methane well.

Although an effective method to degasify the mined coal seam immediately prior to its mining, the short production life of these wells causes their total production to be small, when compared to a vertical fractured well. Figure 13 displays the production history for horizontal wells at each of the four JWR mines. As shown in this figure, the production rates can be highly variable, due to changes in mining rates and operations. As can also be seen in Figure 13, there is a general decreasing trend in production rate from the horizontal wells at the four mines. This is due in part to the effect of pre-mining vertical wells and an emphasis to rely more heavily on these vertical wells to degasify the coal prior to mining. It is anticipated that as future mining occurs, fewer horizontal wells will be required and therefore the production decline should continue.

Figure 14 displays the horizontal well production from the JWR No. 5 mine, the location of the current project. As can be seen, there is also a general decline in production from horizontal wells due to fewer wells being required for methane control and an interruption of mining operations. Of interest is the large increase in production during the latter half of 1994. The rapid increase was due to the installation of numerous wells into a virgin panel followed shortly thereafter by the mining-through (and termination of production) of these wells. This rapid change in production rate from horizontal wells is common and can be expected not only at the JWR mines but at other mines that employ horizontal well degasification.

2.3.3 Gob Wells

The ventilation system is the primary means of methane control at all JWR mines, and gob wells are an important supplement to the control of methane in longwall gobs. Gob wells are drilled from the surface into the area above a planned longwall panel, Figure 15. Following the mining of the coal by the longwall mining operation, the immediate roof fails and collapses into the void behind the mining operation. This collapse creates a lower zone of rock and coal rubble, an intermediate zone of fractured rock and coal, and an upper zone of fractured and sagging coal and rock strata. This zone of disturbed strata (referred to as the gob) has a very high surface area, high permeability, and low reservoir pressure. Because of this, the methane that is contained in the affected coal seams (including some seams below the mined seam which are affected due to stress relief fracturing) flows into the created voids. Without the presence of gob wells, this released methane may enter the active mine workings. However, the gob wells act as low pressure points within the gob such that the methane flows toward and into these wells, thus eliminating the flow of the methane into the mine workings.

The JWR mines in the Warrior basin have not only been a leader in the mining industry in the use of gob wells for effective methane control during longwall mining, but have also been at the forefront in operation of the gob wells to ensure that the gas being produced is primarily the gas that is released from the affected coal seams. If insufficient draw (vacuum) is placed on the

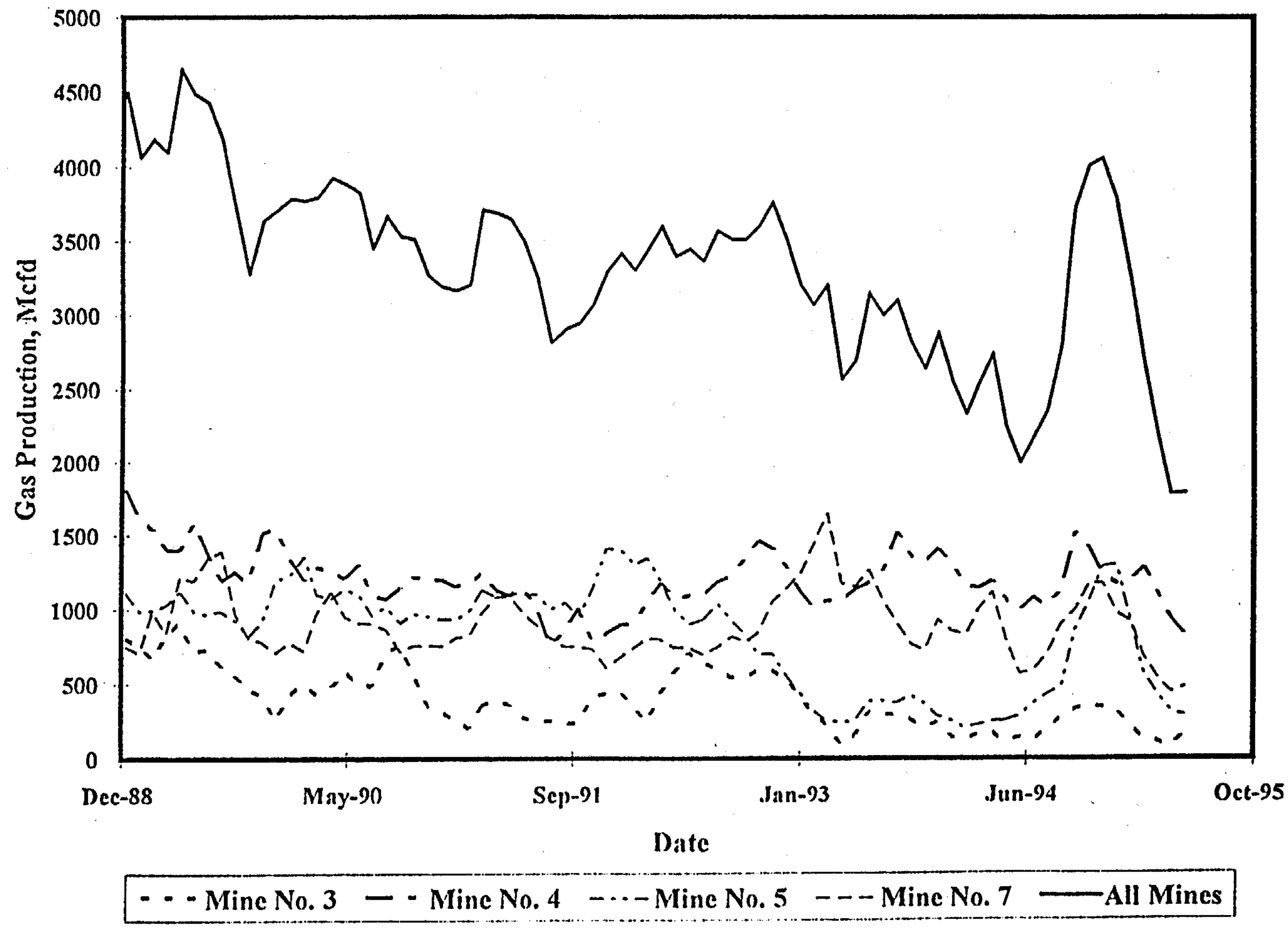

Figure 13. Horizontal well production history (1989-1995).

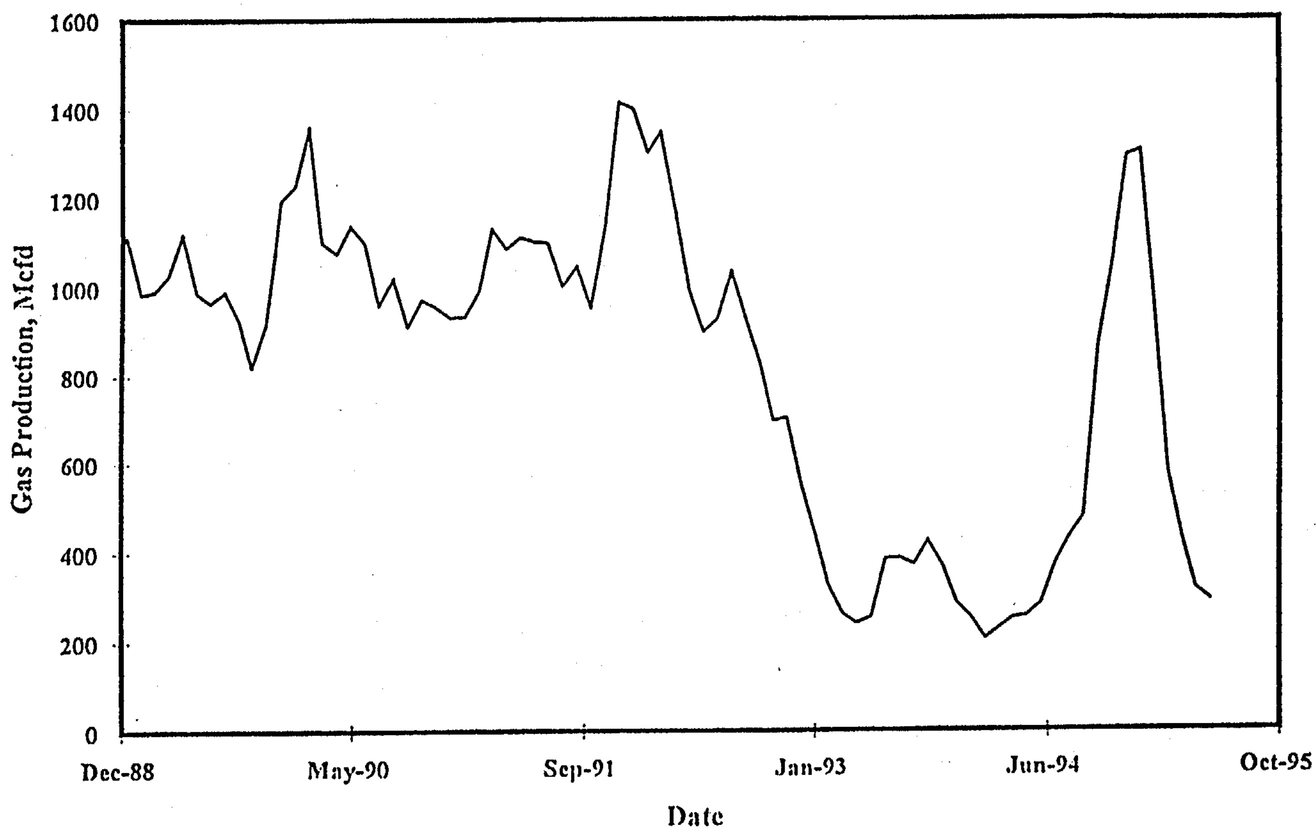

Figure 14. Horizontal well production history for Mine No. 5 (1989-1995).

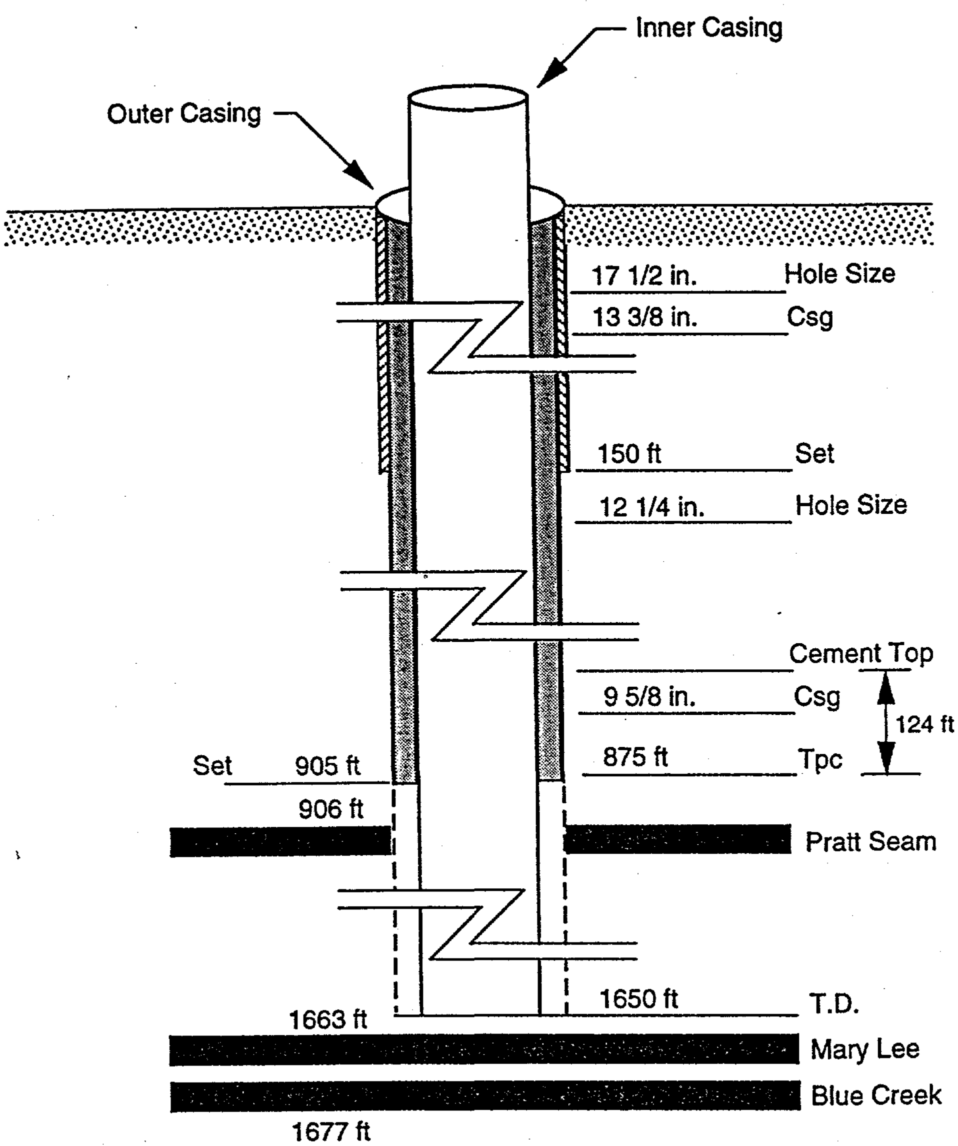

Figure 15. Cross-section of a typical gob well in the Warrior Basin.

wells, some of the methane that is released from the coal flows into the mine workings. If excess draw is placed on the well, the gas that is produced is a mixture of the gas from the coal seams and the gas (air) that is in the underground mine environment. The optimum condition is whereby sufficient draw is placed on the well to prevent the flow of the methane into the mine workings but is not sufficient to draw the mine air into the upper gob area. JWR mines utilize an interactive underground/surface operating system to maximize the methane concentration in the produced gob well gas while preventing methane influx into the mine workings.

Figure 16 details the daily production from gob wells in the four JWR mines during the period 1988 through 1995. As shown, total gob well production, while variable, has typically ranged from 20 million to 35 million cubic feet per day during this period. In comparison to the previously displayed production from horizontal and vertical wells, the gob well production is clearly the dominant form of methane capture at the JWR mines. Methane production from the gob wells currently contributes about 68% of the total methane produced and captured, while vertical wells contribute about 28% followed by horizontal wells at 4%.

Specific gob well production from the JWR No. 5 mine is shown in Figure 17. The production trend is similar to that seen in the horizontal wells in which there was a general decline in production during the period 1991 to 1994 followed by a rapid increase in production to the previous level of about 6 million cubic feet per day. As discussed earlier, the decline was due to a combination of factors, including mining rate and operations. The increase in production observed during 1995 is due the resumption of normal mining operations and the development of new longwall panels (and the concomitant development of new gob wells).

2.4 Ventilation Fan Emissions

The goal of a coal-mine ventilation system is to provide healthy and safe atmospheric conditions for the mine workers. To achieve this goal, the ventilation system must supply an adequate amount of fresh air and dilute toxic, noxious, and explosive gases and dusts to harmless levels while removing them from the mine. In coal mines, the required quantities of air are generally dictated by the amount of fresh air necessary to dilute methane concentrations well below their combustion threshold.

While the production of sales-quality gas from Mine No. 5 is substantial, it represents less than half of the total methane emissions. The bulk of the methane is emitted during ventilation. Figure 18 shows the ventilation exhaust and Figure 19 shows the total methane liberation rates from Mine No. 5 (excluding pre-mining vertical wells). From these figures it can be seen that 60 to 75% of the total methane emissions come from the mine's ventilation system.

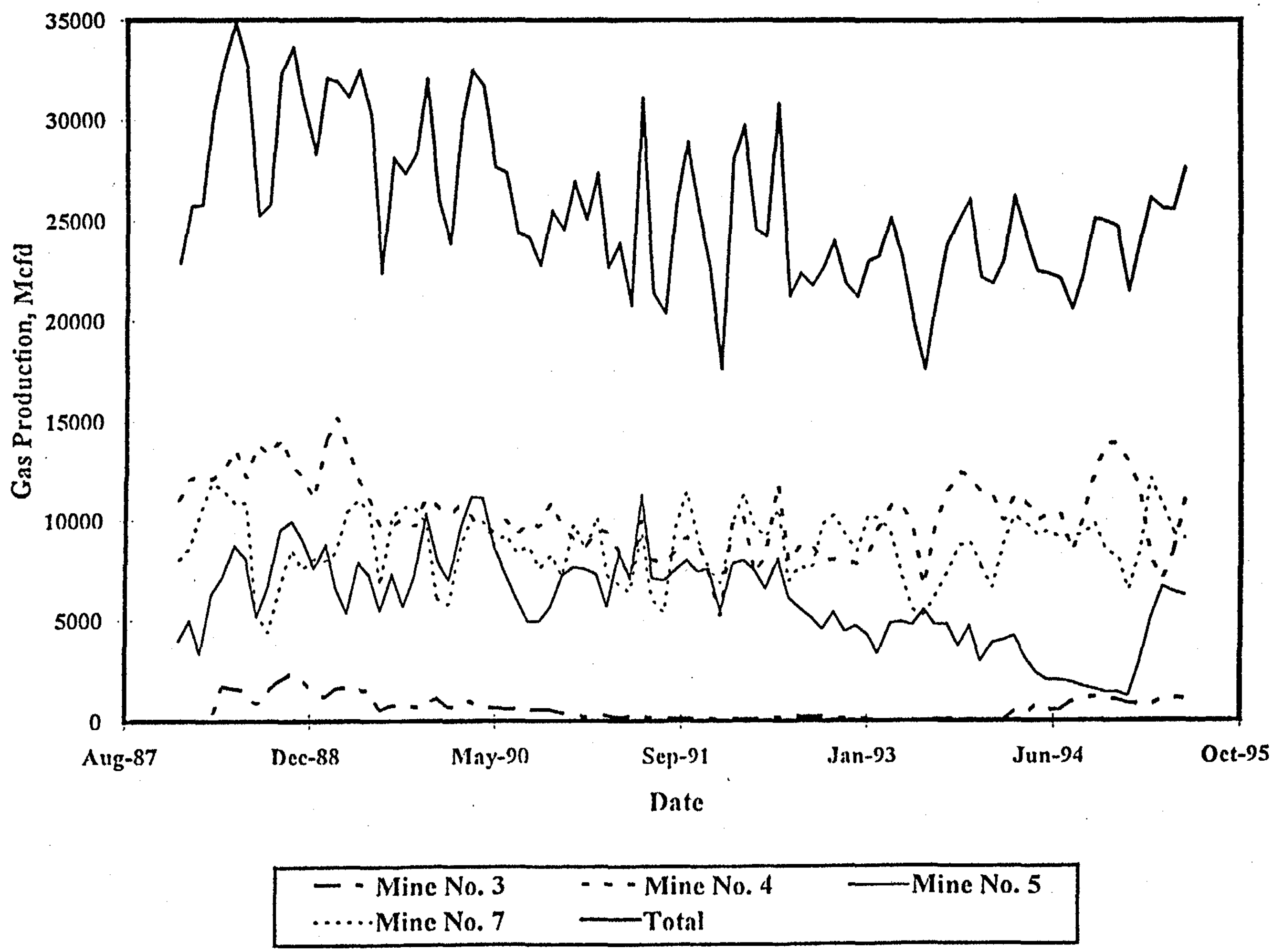

Figure 16. Gob well production history (1988-1995).

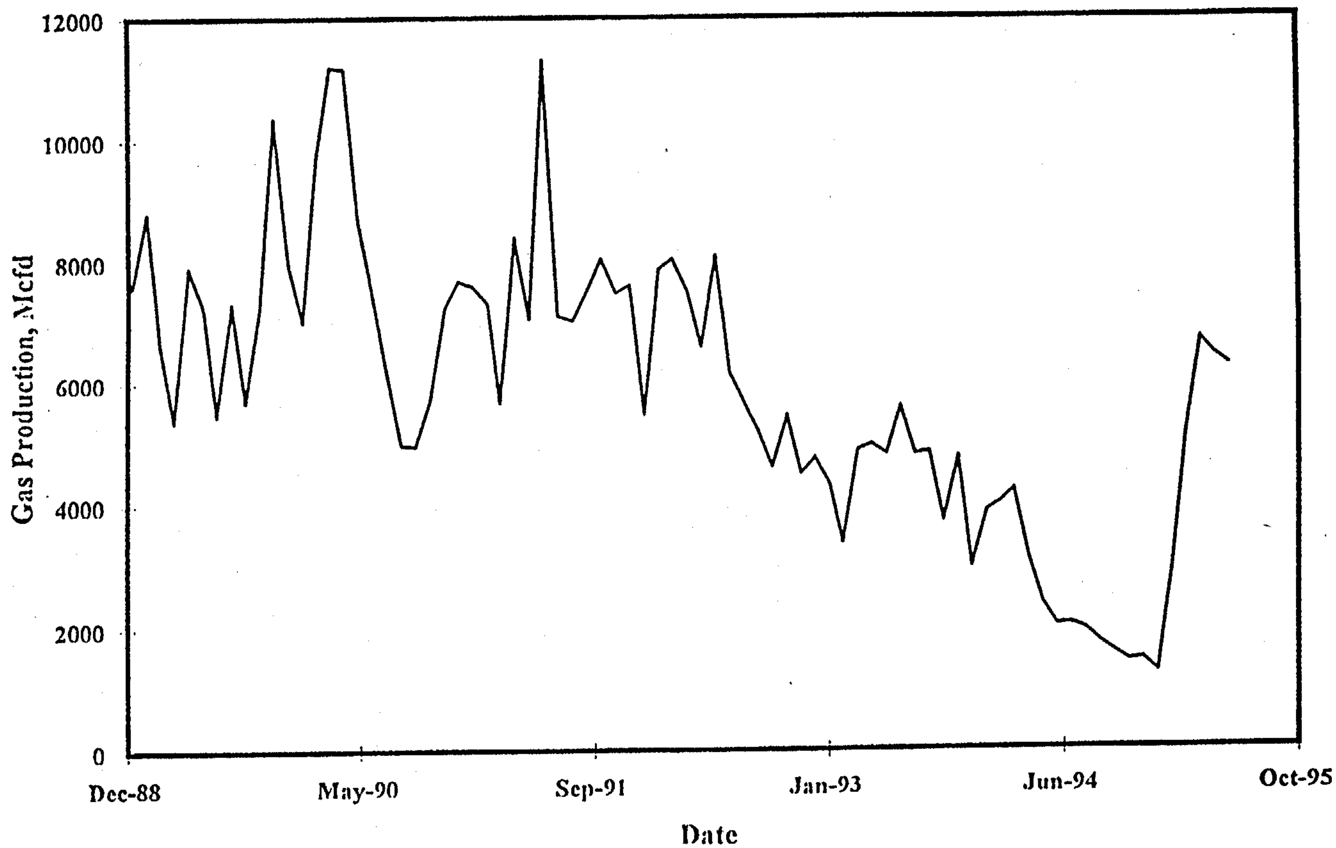

Figure 17. Gob well production history for Mine No. 5 (1988-1995).

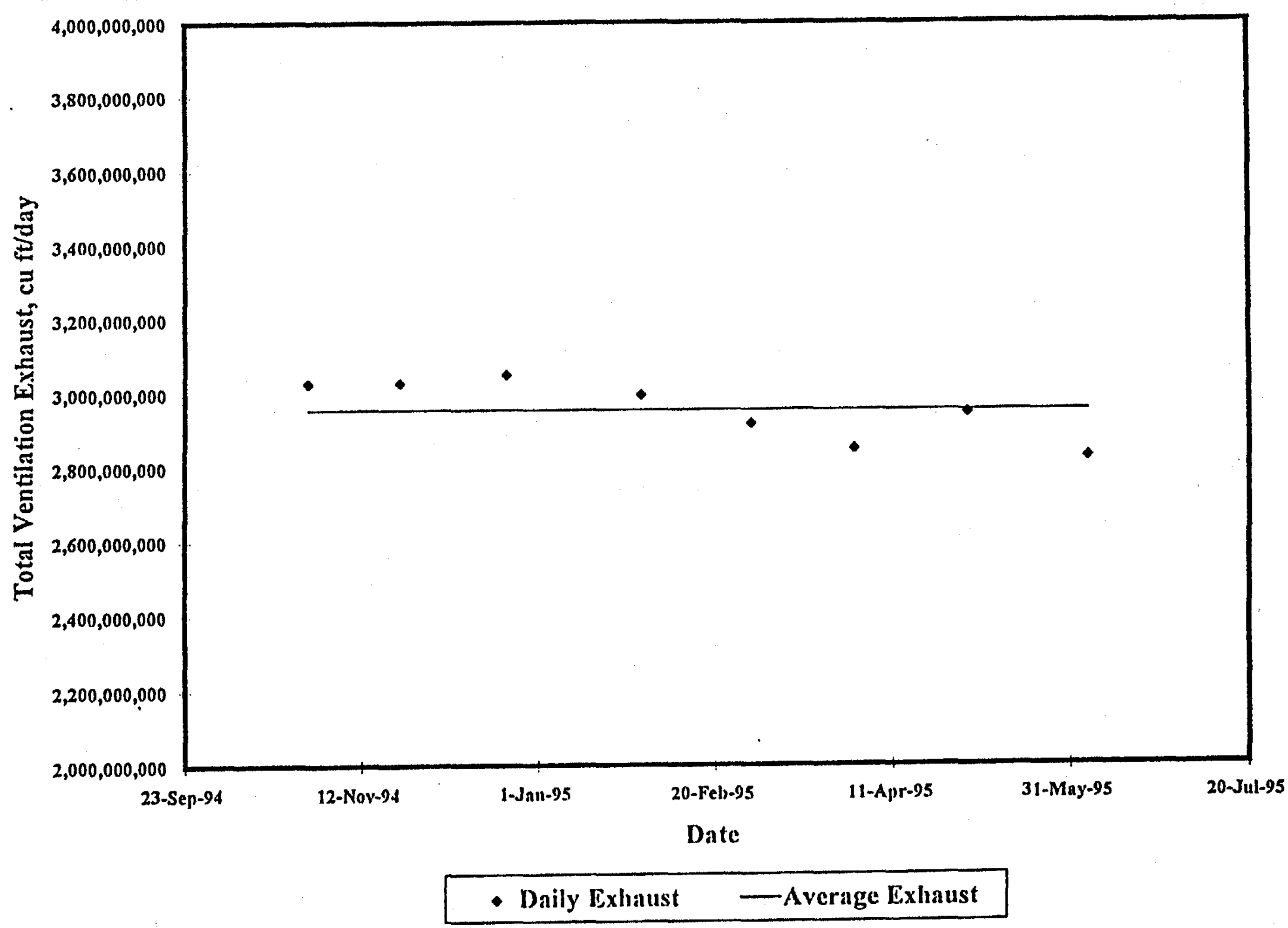

Figure 18. Mine ventilation exhaust for Mine No. 5 (October 1994 - June 1995).

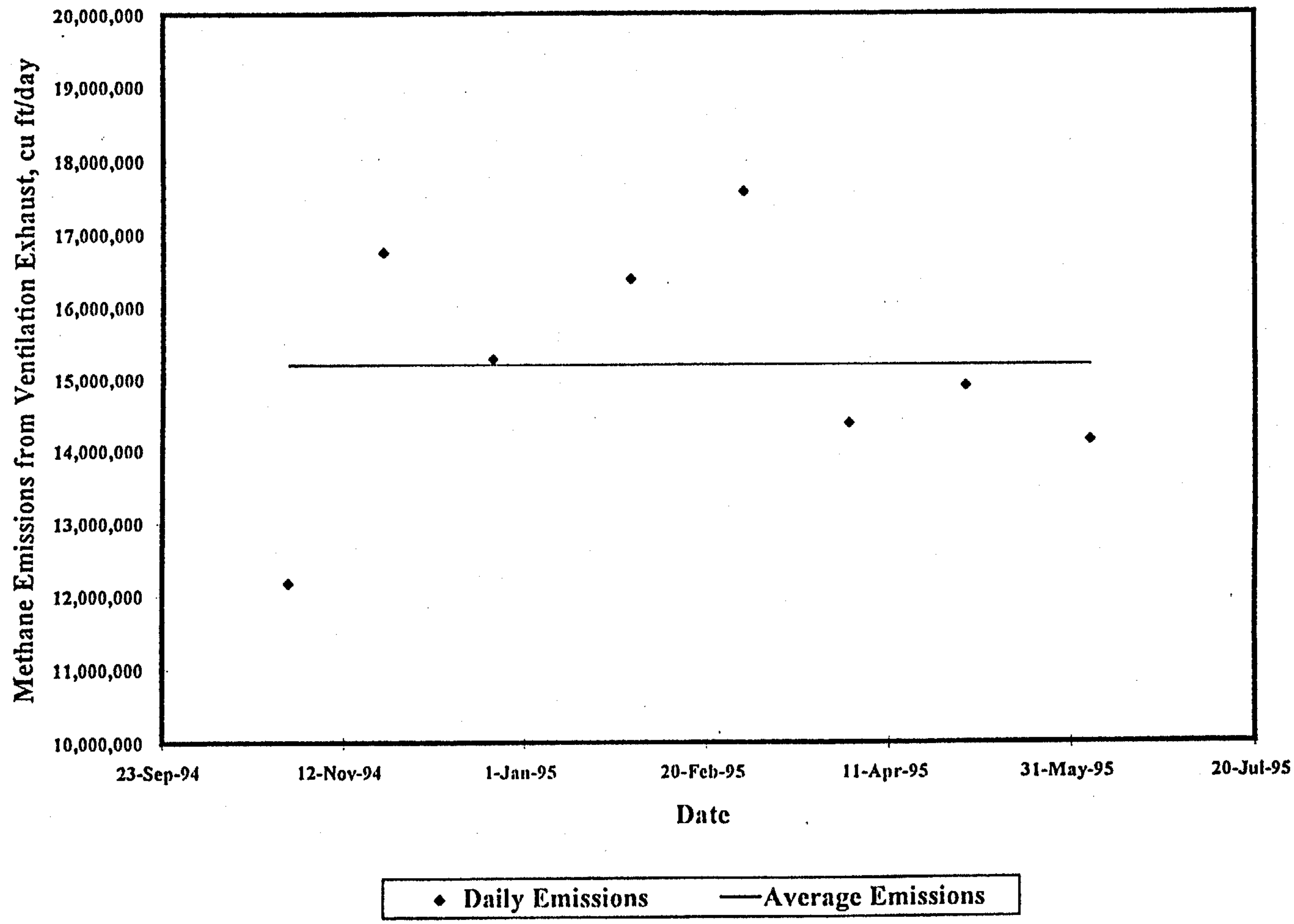

Figure 19. Mine methane emissions from ventilation exhaust for Mine No. 5 (October 1994 - June 1995).

In the No. 5 Mine's ventilation system, the South fan shaft is driven with a single fan that produces an average flow of about 620,000 scfm, with an average gas content of 0.51%. The North shaft has two fans, that together deliver about 1,425,000 scfm with an average gas content of 0.52%. Together these shafts release about 15 mmcf/d of methane to the atmosphere. On a mass basis the release rate is 1,159,000 lb-mass of methane per day.

2.5 Coal Seam Geologic and Reservoir Conditions at the JWR No. 5 Mine

As discussed previously, the coal seams present within the JWR No. 5 mine area are Pennsylvanian-age and bituminous in rank. The coal type is typical of that found within the Warrior and Appalachian basins and generally consists of clarain and vitrain with a total vitrinite content of 70 to 75%. Ash content is low, typically 5 to 10% and is generally described as disseminated to fine laminar mineral matter. The primary coal seam (Mary Lee/Blue Creek) has a vitrinite reflectance (R_0) averaging 1.25, which is indicative of a rank of medium-volatile bituminous. Coal rank varies within the JWR mine area, ranging from low volatile bituminous (R_0 1.55) at the JWR No. 3 mine, northeast of the JWR No. 5 mine to high-volatile bituminous A (R_0 1.17) at the JWR No. 4 mine, immediately north of the JWR No. 5 mine.

Within the area of the JWR No. 5 mine, numerous coal seams occur above and below the mined Mary Lee/Blue Creek coal seam. A representative geologic stratigraphic section highlighting the primary coal seams within the JWR No. 5 mine area is shown in Table 2. Coal seams from seven coal groups are present within the stratigraphic section with a cumulative coal thickness of 35.25 feet. As can be seen, the Mary Lee/Blue Creek coal seams represent 30% of the total coal thickness within the this interval. However, significant coal thickness (and potential gas reservoir) exists above and below this mined interval.

Of particular importance to this project and to the mining operations at the JWR mines is the methane content of the coal. Numerous gas content measurements have been performed on coal core recovered during exploratory drilling. Gas content measurements were made utilizing the U.S. Bureau of Mines Direct Method (Diamond and Levine, 1981). Based on the collected gas desorption results, average gas contents were determined for each of the seven coal groups present within the JWR Mine No. 5 area and are presented in Table 3.

Limited measurements of other coal seam reservoir properties exist for the coal seams within the JWR mine area. From tests performed in areas adjacent to this area, it can be extrapolated that the virgin reservoir pressure is near hydrostatic (0.39 to 0.41 psi/ft) and the permeability is in the range of 5 to 20 millidarcy (Schraufnagel, 1991).

Table 2 - Representative Coal Seam Stratigraphy for the JWR No. 5 Mine, Well S-0518-S

COAL GROUP	COAL SEAM	DEPTH, ft (TOP)	THICKNESS, ft
Utley	Clements	301.00	1.00
	Clements	323.00	1.15
	Clements	432.50	0.25
	Subtotal	-	**2.40**
Gwin	Gwin	726.00	2.30
	Gwin	730.00	0.35
	Thompson Mill	786.50	0.50
	Subtotal	-	**3.15**
Cobb	Upper Cobb	975.00	0.35
	Upper Cobb	978.50	0.35
	Cobb Split	1018.15	0.35
	Cobb Split	1038.00	0.30
	Subtotal	-	**1.35**
Pratt	Pratt	1388.00	1.15
	Pratt	1396.00	0.90
	Pratt	1398.00	0.40
	Pratt	1403.50	1.50
	Nickel Plate	1434.65	0.35
	Nickel Plate	1440.00	1.00
	Nickel Plate	1460.00	1.20
	America	1513.00	1.75
	Subtotal	-	**8.25**
Curry/Gillespie	Curry	1620.00	0.55
	Gillespie	1698.50	0.60
	Gillespie	1707.00	0.45
	Subtotal	-	**1.60**
Mary Lee	Upper New Castle	2072.50	1.50
	Mary Lee	2108.00	2.00
	Blue Creek	2113.75	8.40
	Jagger	2154.50	1.50
	Subtotal	-	**13.40**
Black Creek	Jefferson	2339.00	1.00
	Jefferson	2343.00	0.75
	Jefferson	2367.50	0.50
	Jefferson	2377.00	0.60
	Murphy	2541.75	0.50
	Black Creek	2557.50	1.75
	Subtotal	-	**5.10**
	TOTAL	-	**35.25**

Table 3 - Average Coal Seam Gas Content for Seven Coal Groups in the JWR No. 5 Mine Area

COAL GROUP	GAS CONTENT cubic feet per ton
Utley	150
Gwin	300
Cobb	350
Pratt	400
Gillespie/Curry	400
Mary Lee	500
Black Creek	550

2.6 Methane Resources for the JWR No. 5 Mine

Using the collected geologic and coal seam reservoir data, preliminary estimates of the gas resource contained in the coal seams within the JWR No. 5 mine area were made. However, it is appropriate to further discuss the reality of estimating coalbed methane resources within an area where active mining is occurring before presenting the summary results.

Gas resource (natural gas, coalbed methane, shale gas, etc.) estimates are an integral part of the conventional natural gas industry. These estimates provide an initial indication of the quantity of gas resource that is present within the rock formations and provide an important input into estimating potential recovery of that gas. The estimation of gas resource is generally a function of void space (porosity) within the rock units, the pressure of the gas within the void space, and specific gas properties of the captured gas. This method is modified slightly for the unique characteristics of gas storage in coal (sorption), but nonetheless it is an attempt to measure the volume of gas that is contained within a certain volume of reservoir rock.

For gas reservoirs (including coal seams) the determination of the quantity of gas that is stored is therefore a straightforward process. However, this assumes that the reservoir has been unaffected by any man-made operation. If the reservoir is disturbed (for example, if part of the reservoir has been produced via producing gas wells) then the determination of gas resource in-place becomes much more difficult. This problem escalates rapidly for coal seams that have been affected by underground mining operations.

In the case of coalbed methane resources present within a mining area, generally three resource types need to be considered. The first type, and often the easiest to determine, is the quantity of gas resource that is present within the coal that is outside of the current influence of the mining activity. This resource could be considered similar to a gas resource in a virgin state because the reservoir properties (primarily reservoir pressure) have not been impacted by the mining operation. Accordingly, the gas resource is estimated using the standard volume relationships described above (i.e. gas content [in cubic feet per ton of coal] x unmined coal resource [tons] = gas resource [cubic feet]).

The second type of gas resource is that which is contained within the unmined coal that is present within the active mining areas. This resource is primarily contained within the unmined pillars in the mining area and in the coal seams above and below the mined seam. While the method of determining the gas resource is the same as that for the unmined virgin coal reservoir areas, the major problem is determining the gas content of the coal in these disturbed areas. It can easily be seen that the gas content of the coal should be lower than that originally in-place. However, there has been little work performed to date to quantify this volume. Importantly, the percentage of gas that remains in this type of coal reservoir will be very dependent upon not only the reservoir properties of the coal (especially permeability, reservoir pressure, and initial gas content) but also will be dependent upon the impact of the mining operation on these properties. Therefore, estimating the gas resource that is in-place within the active mining area is difficult and open to a large degree of uncertainty.

The final type of gas resource that is present is the free gas (and to a lesser degree the sorbed gas) that exists within the gob areas above and below extracted longwall panels. This third type of resource is the most difficult to estimate due to the uncertainty associated with 1) the pore volume within the gob area; 2) the amount of gas that has been lost from the gob area into the mines ventilation system; and 3) the source and quantity of gas that has migrated (or is migrating) into the gob's pore space. Some attempts have been made to estimate the maximum volume of the gas that could originally be contained within a gob, but this has basically been to determine the amount of gas-in-place in the virgin, unmined coal. Clearly the current amount of gas that is in place is somewhat less than this and with time this quantity should continue to decrease.

Therefore, to determine the gas resource that is present within the JWR No. 5 mine area, it was decided to only evaluate the gas resource within the unmined coal areas. The authors recognize that there is a significant quantity of gas present within the other two resource categories, but that limited data precludes any reasonable estimate of this gas volume. However, it should be noted that while estimates of resource volume within these two categories were not determined, the potential reserves (i.e. future recoverable resource) of these can be estimated. These volumes (including the methodology for determination) are presented later in this report.

Using the average gas contents, typical thickness for the coal seams present, and a coal density of 1,800 tons per acre-foot, estimates of gas resource in-place within the JWR No. 5 mine area were made. Presented in Table 4 below are the average gas resource estimates (per square mile of reservoir) by coal group.

Table 4 - Coalbed Methane Resource In Unmined Areas of the JWR No. 5 Mine

COAL GROUP	THICKNESS ft	GAS CONTENT cu ft/ton	GAS RESOURCE billion cu ft/sq mi
Utley	2.40	150	0.415
Gwin	3.15	300	1.089
Cobb	1.35	350	0.544
Pratt	8.25	400	3.802
Gillespie/Curry	1.60	400	0.737
Mary Lee	13.40	500	7.718
Black Creek	5.10	550	3.231
TOTAL	35.25	-	17.536

3.0 Phase I — Task 2, Evaluation of Coal Mine Methane Reserves

3.1 Objective

The intent of this task is to perform an assessment of the potential reserves of methane that could feed the proposed gas turbine. This task includes an evaluation of the environmental and legal aspects of methane utilization, an assessment of the mine ventilation and methane drainage practices, an economic assessment of the reserve potential, an assessment of the methane emission source, and the determination of the potential size and flow rate of the low concentration methane flow streams.

3.2 Legal Issues

From the onset of development of coalbed methane, there have been conflicting claims of ownership to the resource (Norvell, 1990). Owners of the mineral interest in coal claim that coalbed methane is included in the ownership of the coal or the right to extract the coal because it was produced from or is contained in the coal. The basis of the claim by owners of the mineral interest in oil and natural gas generally is that coalbed methane is physically and chemically indistinguishable from natural gas. Methane is, in fact, the principal constituent of natural gas, often constituting more than 90% of its gaseous fractions. The Federal government takes that latter position — essentially that "gas is gas" — with regard to the extraction of minerals owned by the United States (Solicitor's Opinion, 1981). Finally, in cases where the coal interest and the interest in oil and gas have been severed or separately conveyed, there are occasional claims by the owners of the reserved or residual mineral interest that coalbed methane is not part of either the coal or oil and gas estates.

There have been numerous court cases involving conflicting ownership claims to coalbed methane. Most of these cases have been in Alabama or Appalachia (Norvell, 1990). There has also been legislation passed by a few states in attempts to resolve the ownership issues sufficiently to encourage development (Virginia Oil & Gas Act, 1989). A full discussions of these cases and statutes is beyond the scope of this report. However, any person considering the utilization of coalbed methane as outlined in the report must realize that the legal question of ownership of coalbed methane is a threshold issue which must be addressed early in the evaluation of a potential project. The issue may be capable of resolution through legal or administrative means or through the design and operation of the project. If ownership can be resolved, there may arise questions of whether a royalty or other payment due upon severance of a mineral is owed and how such payments may be computed. This is discussed in more detail below.

The origins of the conflicting claims of ownership is the fact that mineral interests have in the past been conveyed without discussion of the ownership of or right to exploit coalbed methane. Generally speaking, this was due to the fact that the economic production of coalbed methane is a relatively recent phenomenon. Therefore the methane contained in the coal or surrounding strata was viewed as, at best, a noncommercial mineral and, at worst, a serious hazard to underground mining. The lack of any indication that coalbed methane was or could become a commercial resource meant that most conveyances or leases of oil and gas or coal were silent or ambiguous with regard to the transfer of or right to develop coalbed methane. When commercial production of coalbed methane was finally attempted and achieved, this potential for conflict led to legal actions being taken in several states. Not only did these actions impede development of the projects involved, but widespread knowledge of the suits served to stifle development in areas where potential conflicts in ownership were readily apparent and not easily resolvable.

The potential for conflict should be expected in any situation where the conveyance of the mineral interest in coal does not discuss the beneficial use or commercial sale of coalbed methane by the coal miner. This expectation should be greater in coal basins where oil or conventional natural gas has also been produced. This will be due to the fact that in basins with production of liquid or gaseous hydrocarbons there will be a heightened awareness in the legal community and the general public of the possibilities of revenue from the production of gas.

For any person acquiring mineral interests for the purpose of opening or expanding an underground coal mine, it is imperative that the grant of the new mineral interest conveys the right to the commercial sale or beneficial use of coalbed methane. In the case of the commercial sale of the gas or its conversion to some other marketable product, such as electric power, the computation and allocation of royalties should be addressed through lease clauses which take into account the peculiar problems which occur when gas is produced in conjunction with coal mining. Where the gas is used exclusively on the mine premises with no commercial sale, it may not be unreasonable to expect the mineral owner to convey this right without a royalty requirement. This would be much in the same fashion as the grant to the miner of the right to use for the purpose of facilitating mining and without fee or royalty minerals or resources, such as water or sand and gravel, which may be found on the leasehold. However, if the grantor of the coal does not own the rights to coalbed methane, any use of the coalbed methane by the miner will likely carry with it a royalty obligation.

In the acquisition of the mineral interests or prior to production of methane, serious thought must be given to mechanisms for pooling or unitizing the royalty interests. Otherwise the computation of royalties may become cumbersome or lead to conflicts. This possibility would be most pronounced in the case of utilization of gob gas or gas taken from ventilation outlets. For example, a longwall panel 900 feet wide by 6,000 feet long covers an area of approximately 124 acres. Analysis may indicate that all or most of the gas which might be produced from the panel's gob come from strata immediately above or below the gob. However, if the miner attempts to limit the allocation of royalty to those mineral owners of the 124 acres overlying the panel, as might be done in the case of coal production, it may provide an open invitation to adjoining mineral owners to assert their claims. Unitizing all or a portion of the mine and pooling production form all gob wells within the unitized area provides the simplest method for dealing with conflicts in advance. Pooling and unitization also have the advantage of being methods which are familiar to the regulatory agencies and courts in states with oil and gas production. Black Warrior Methane Corp., the company which operates the degasification system for Jim Walter Resources, Inc., relies upon the laws and regulations of the State of Alabama and the Alabama Oil & Gas Board regarding the pooling and unitization of mineral interests affected by mine degasification (Blackburn, 1995).

The laws and regulations in Alabama regarding pooling and unitization follow generally a model based on oil and gas experience. This model may not be the best guidance with regard to production of either gob gas or utilization of ventilation gas. The Virginia statute may provide a better example of the direction regulation should take for mine gas development and utilization. The Virginia law requires that drilling units follow the mine plan, if there is one, and that well spacing conform to mine operations. This approach makes much more sense than to unitize on the conventional oil and gas model. Oil and gas units generally conform to governmental units, i.e., 40 acre, 80 acre, 160 acre, etc., sized drilling units. It would be the most unlikely happenstance if a mine plan conformed to such units.

Pooling and unitization of the entire mine or large areas of the mine associated with a common ventilation plan are the only options which appear to be feasible with regard to determining royalties from the sale or use of ventilation gas. There appear to be difficulties which cannot be overcome practically in proving the area of origin and proportionate amount of production of methane entrained in the ventilation system and ultimately exhausted by the main fans.

3.3 Regulatory Issues

In constructing a facility at or near the main exhaust fans, the principal regulatory issues will involve MSHA regulations requiring an approved plan to locate sources of combustion or combustible materials within 100 feet of the "main fans" (CFR). The primary fuel of the turbine project proposed in this submission will be natural gas. The combustion chamber of a turbine is inarguably a source of combustion. The regulations do not describe that point on the main fan housing or machinery from which the 100 foot setback will be measured nor do they define "main fans" sufficiently to determine that point. From dealings between JWR and MSHA over several years, it appears that the 100 foot distance will be measured from the last moving part of the fan. If that is the outcome in all cases, as discussed in this report, then no MSHA approval would be required for pipelines or turbines located more than 100 feet from the fan blades. Design and engineering must then take into account the cost of compliance versus the capital and operating cost of constructing outside the 100 foot limit. This regulation does not present any significant engineering difficulties. The incremental cost to locate the turbine 100 ft from the fans will be negligible.

3.4 Environmental Issues

The two sides of the environmental issues of this project are examined, the beneficial aspects and the negative effects.

The primary beneficial aspect of the proposed project is substantial. Methane is believed to have a global warming potential about 24.5 times that of an equal weight of carbon dioxide. When one pound of methane from the ventilation air is burned, 2.75 lbs of carbon dioxide are produced and released, while 24.5 equivalent pounds are *captured*, producing a net reduction of 21.75 lbs of CO_2 equivalents per pound of waste-methane that is burned. In other words, the JWR Mine No. 5 currently emits 15,500,000 lbs of CO_2 equivalents per day in the ventilation stream. If all of that methane were combusted into carbon dioxide, then the rate would be reduced by 89% to 1,700,000 lbs/day (a reduction of 13,800,000 lbs/day).

No matter whether the single gas turbine unit proposed in this project uses as its primary fuel natural gas already in or gob gas destined for a pipeline, the fact that between 10% and 62% of the energy consumed by the unit is derived from the methane contained in the mine exhaust stream means that at least 34,080,000 cf of methane emissions are converted to CO_2 each year. If the primary fuel source for the unit is gob gas that would otherwise be vented to the atmosphere, or a higher percentage of fuel comes from the mine exhaust stream, then the beneficial effects are increased.

It is assumed by this project that the entire output of the turbine will be electric power. Assuming an average value of 28 million Btu's/ton of coal, production of electric power as proposed will eliminate the need to produce 12,200 tons of coal per year for a nominal 3.4 MW power turbine. Examining the air pollution benefits of the project, each turbine unit reduces mine emissions by 6.1 mmcf/year of methane if it is assumed that, on average, each ton of coal mined results in the release of 500 cf of methane. A further reduction in greenhouse effects is achieved due to the substitution of methane for coal as a fuel for power generation. This is due to the fact that the combustion of methane results in the production of 35% of the CO_2 that would be produced by the combustion of coal for an equivalent amount of heat energy (EPA/430-R-95-003, 1995).

The environmental benefits of this project far outweigh the potential negative effects. The principal harmful effect is the generation of CO_2 as a byproduct of the combustion of methane. In addition, a minimal level of CO is produced. CO is not a greenhouse gas but is toxic in sufficient quantities. The relatively low amounts of CO produced by the unit and the operating conditions of the unit indicate that the CO produced should constitute little or no environmental risk. However, if removal of CO from the turbine exhaust is deemed necessary, it can be eliminated by the use of scrubbers or a catalytic combustor. Scrubber units are relatively inexpensive and simple and should have a negligible effect on the operation and economics of the turbine.

A turbine can emit high levels of noise. However, the housing for the turbine described in this report is designed to reduce noise to an acceptable level.

3.5 Mine Ventilation Practices

A ventilation schematic (typically used for computer simulations) for a mine with two longwalls and five continuous-miner sections is shown in Figure 20. Although continuous miners contribute to the mine's overall coal production, their major function is to develop the main and

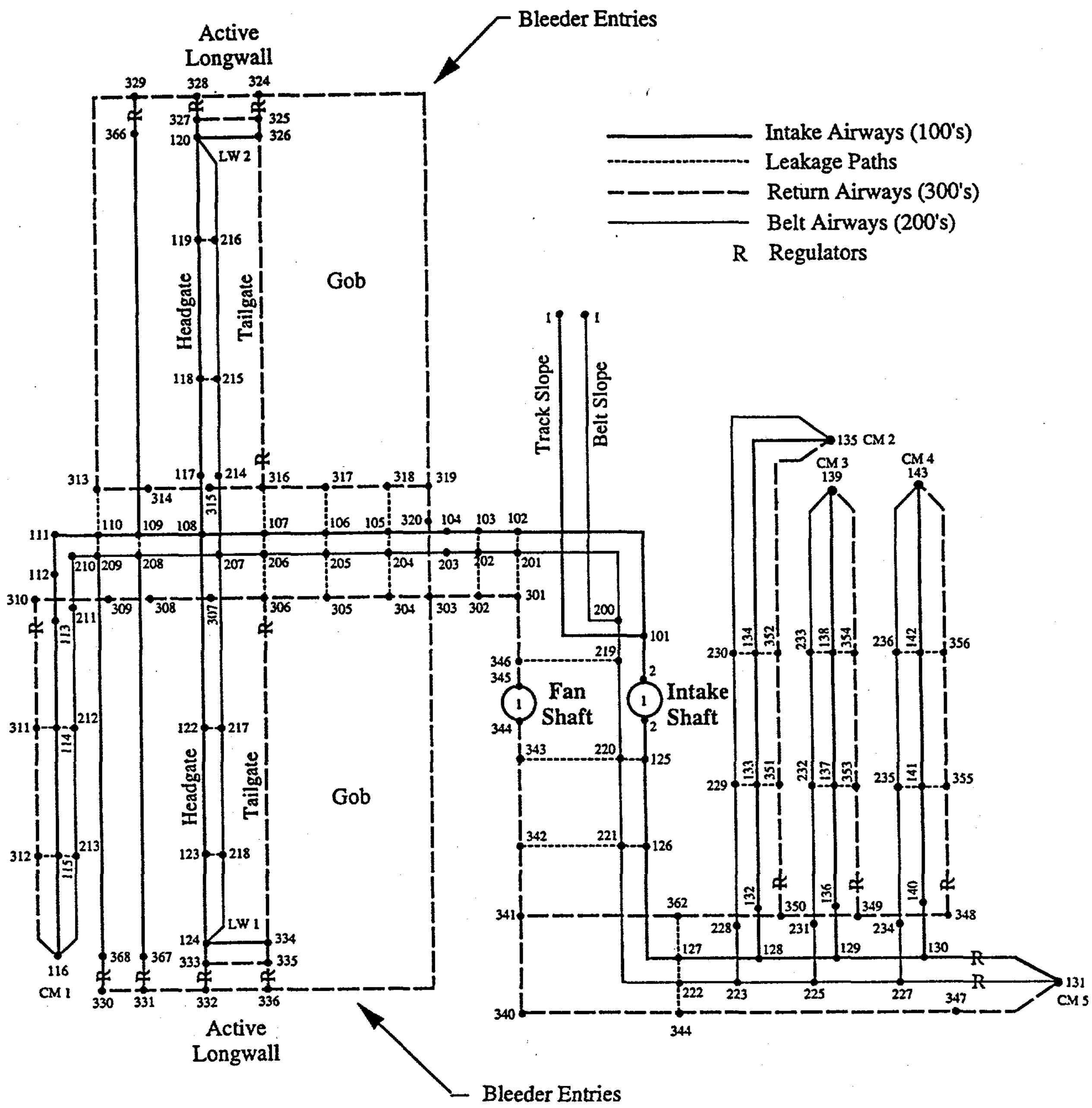

Figure 20. Ventilation schematic for a mine with two longwalls and five continuous miner sections.

longwall-gate entries for the haulage and ventilation system; whereas, the majority of the mine's coal production comes from the longwall sections. Figure 21 shows the various types of airways that are encountered in a mine-ventilation system. Intake airways, which course the fresh air from the intake shaft to the working sections, are designated by heavy solid lines. Return airways, represented by heavy dashed lines, carry the contaminated air away from the working sections to the exhaust (fan) shaft. Main ventilation fans must be located on the surface. A generalized representation of a main ventilation fan is shown in Figure 22 and a photograph is shown in Figure 23. Most coal mines use an exhaust system, as compared with a blower system, for ventilation. With an exhaust system, the pressure inside the mine is below atmospheric pressure; whereas, the pressure in a blower system is above atmospheric. The selection of an exhaust system over a blower system is a practical one. Elevators, which are used for transporting men and materials between the mine and surface, are required to be located in an intake shaft. Thus, an elevator would interfere with locating a fan at the same shaft. Belt airways are shown as fine solid lines in Figure 20. The Code of Federal Regulations (CFR) requires belt airways to be located on a neutral split of air which cannot be used as an intake or return airway; however, some mining companies have successfully petitioned the Mine Safety and Health Administration (MSHA) to permit the use of belt airways as intake airways, provided special safety precautions are utilized. The last type of airway shown in Figure 20 is not really an airway; instead, it is a representation of various sources of air leakage, such as stoppings and overcasts, and is indicated by a fine dotted line. Depending on the quality of the ventilation practices for a given mine, leakage can range from 25 to 50% from the fan to the working sections. It should be noted that each type of airway in Figure 20 can, and usually does, represent multiple airways connected in parallel, with the exception of a belt airway.

As the longwall system advances, the area, behind the roof supports, caves and forms the *gob*, as labeled in Figure 21. It is not possible to inspect this caved, mined-out area. Therefore, a controlled flow of air is established through the gob to reduce the accumulation of methane. This type of control is referred to as *bleeding* the gob. Regulators control the flow of air from the gob into the bleeder entries, which partially surround the periphery of the gob. The regulators should be accessible from the bleeder entries for adjustment, measurements, and inspection. The CFR limits the maximum concentration of methane in the bleeder entries to 2%, whereas, only 1% is permitted in other return airways.

A more detailed diagram of the ventilation system for an individual longwall section is presented in Figure 21. A variety of ventilation schemes can be used to ventilate a longwall section, and the one illustrated in Figure 21 is only one example. In Figure 21, the headgate entries are located on the left side of the block of coal being extracted. Three of the four headgate entries are used as intake airways, including the belt entry which is located adjacent to the block of coal being longwall mined. The fourth entry is used as a return to dilute methane generated from the adjacent block of coal which will be mined in the next panel. The intake air in the headgate is

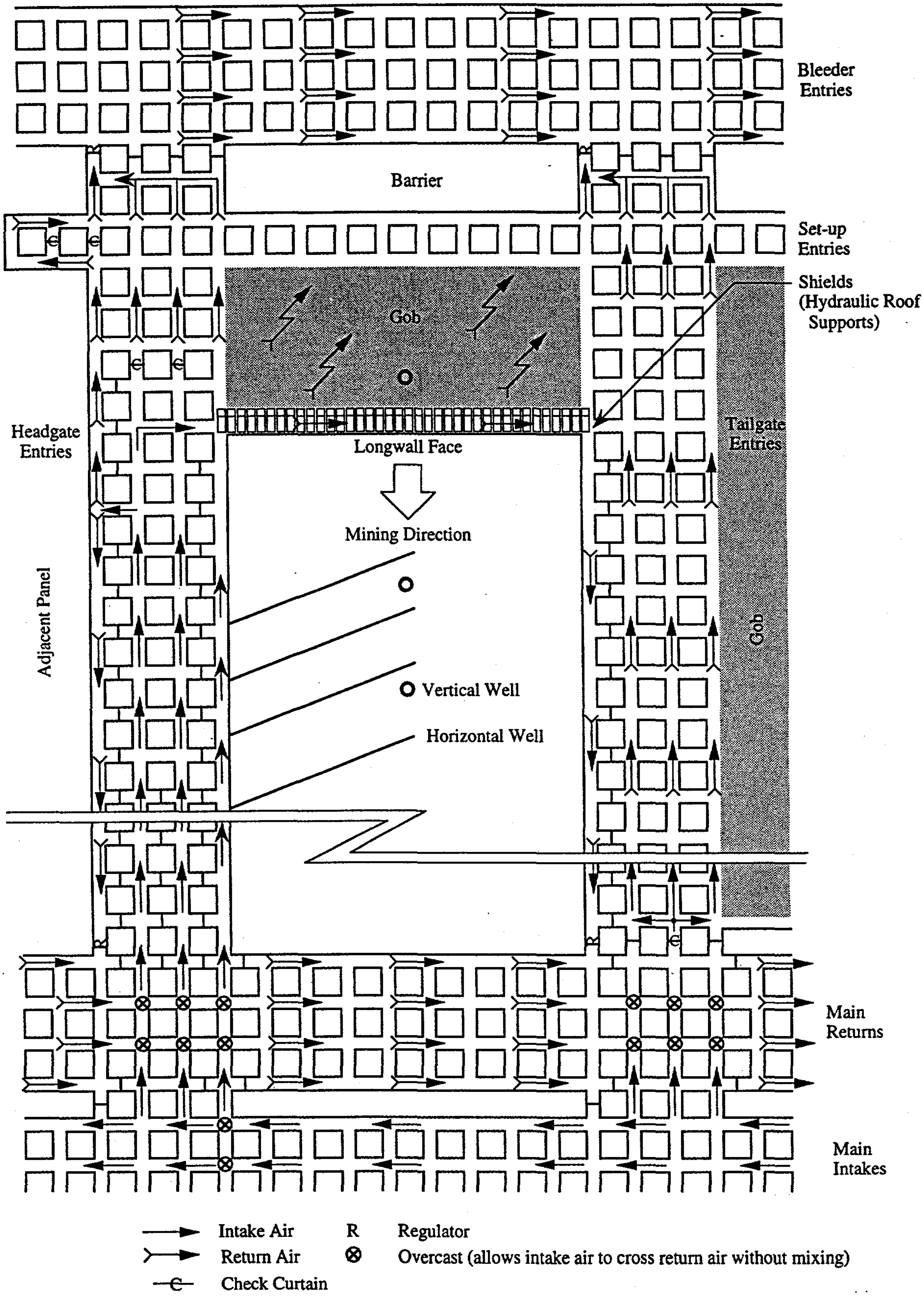

Figure 21. Ventilation of a longwall mining section.

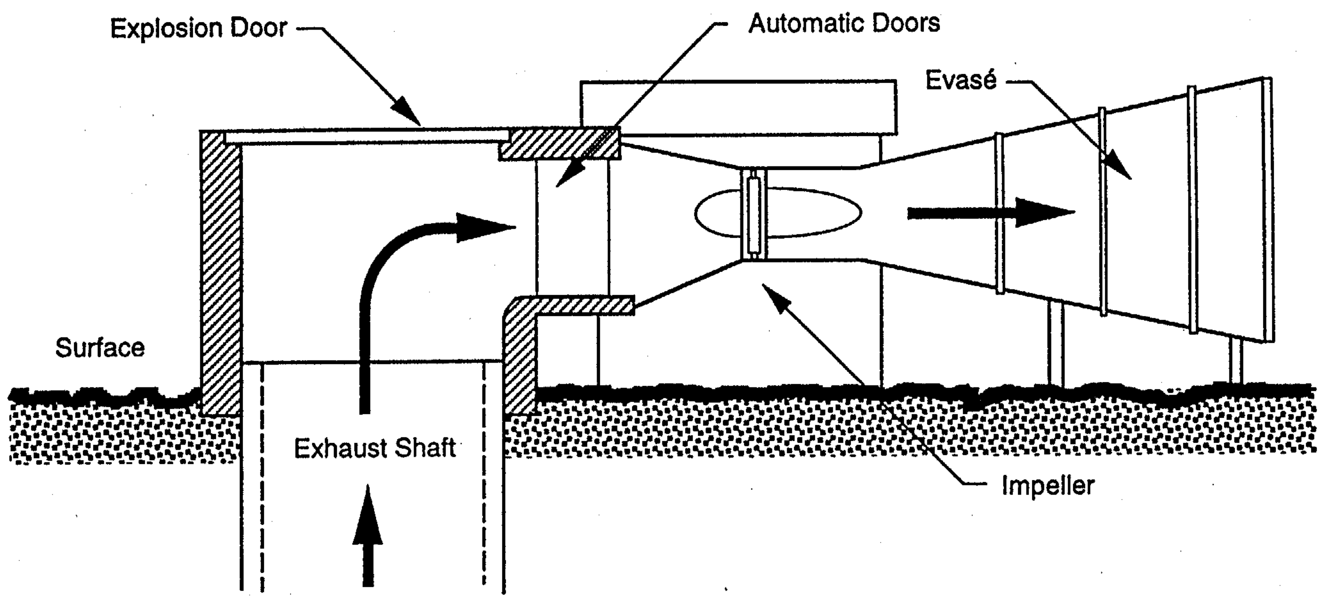

Figure 22. Side view of a main ventilation fan.

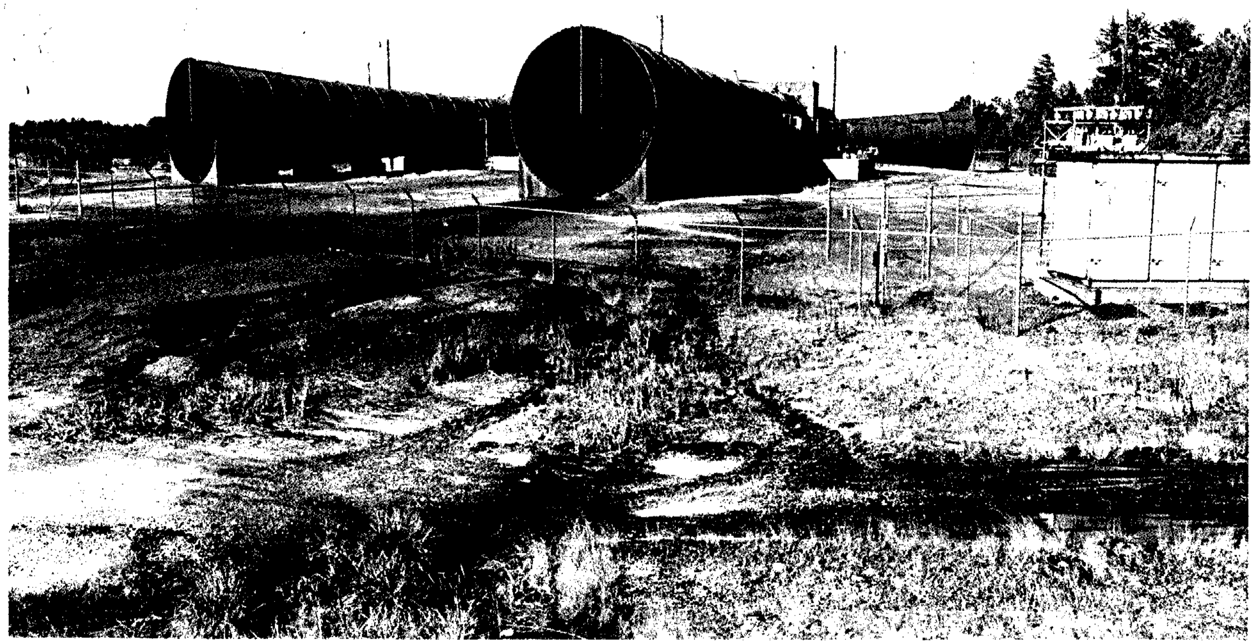

Figure 23. Ventilation shaft fan 4-6, showing two primary fans and one backup. The two 750-hp fans each draw 750,000 scfm through a common 22-ft diameter shaft.

supplied from the main intakes, located at the bottom of the diagram, and is used to ventilate the longwall face, where mining occurs, and the gob through the bleeder entries, located at the top of the illustration. The tailgate entries are located on the right-hand side of the block of coal being mined. Intake air is supplied to three of the tailgate entries to ventilate the adjacent gob of the previous panel. The air in the forth tailgate entry, the one closest to the block of coal, is directed back to the main returns. The quantities of air flowing into the bleeders and main returns are controlled by regulators, which are labeled with the letter "R". For simplicity, the pillar configuration for the head and tailgate entries of Figure 21 actually deviates from that used in the Warrior Basin of Alabama. Instead, because of the deepness of the Blue Creek coal seam and the accompanying ground pressures, a yield-pillar system is commonly used. However, Figure 21 accurate represents a typical ventilation system.

For the section layout in Figure 21, set-up entries are developed for installing the longwall equipment. This technique provides a barrier pillar to separate the bleeder entries from the gob area, thus reducing problems with roof control in the bleeders. Figure 21 also shows the use of horizontal degasification wells and vertical gob wells. With horizontal degasification, methane is collected by means of horizontal wells drilled into solid blocks of coal (before longwall mining) as the mine development progresses. Whereas, gob wells are used to collect methane generated in the caved and abandoned areas of the mine created by longwall mining. Methane collected from degasification wells in advance and gob wells during the mining process is obtained in medium and high-quality forms, while methane emitted by the ventilation system at the fans is in a low quality form.

3.6 Methane Drainage Practices

Methane can enter the mining area from the coal seam being mined and from the surrounding coalbeds as a result of fracture development and caving. The actual emission zone is a three-dimensional area surrounding the working face, including the caving zone (gob area), fracture zone, and yielding zone. There is evidence that methane is also emitted from nearby seams when the roof falls and floor heaves. Three coal groups, Cobb, Pratt, and Black Creek, are considered major contributors to gob gas production in the Warrior Basin of Alabama. Thus, the degree of methane emission is closely related to geomechanical characteristics, such as strata yielding due to pressure, fracture development in the overlying strata, and roof caving.

Methane is contained under pressure within the micropores, joints, and fractures of coalbeds. Fractures are formed in the highly stressed or relaxed zone of the mining area (Diamond and Ulery, 1991; Layne et al., 1987), and gas flows, by Darcy flow, through the network of cracks contained within the coal structure and adjacent strata toward a low pressure region (working face or gob area). Methane liberation is closely linked to coal face movement in longwall mining (McCulloch and Daurice, 1973) and is dependent on development of fractures in roof strata (McPherson, 1975). Furthermore, the permeabilities in the emission zone are increased because of mining and may be the principal factor controlling gas emission into the working and gob areas.

Methane collected from degasification in advance and during the mining process is obtained in medium and high-quality forms. Methane exhausted by the ventilation system from a mine fan is emitted in a low-quality form. The main use of medium and high-quality methane is power generation from a pipeline connected to a utility or gas supply directly to the user. On-site power generation is especially attractive in remote locations with managed peak demand systems in place. As proposed in this report, low-quality gas can be used as combustion air at a mine-mouth power generation plant.

The recovery of methane with regards to coal mining has essentially been performed by the following three techniques: vertical-well degasification, gob-well degasification, and horizontal-well degasification. With vertical degasification (Figure 3), methane is removed from the coalbed and collected at the surface prior to mining (typically a few years in advance).

Gob wells are used to collect methane generated in the caved and abandoned areas of the mine created by longwall mining (Figure 5). Gob wells are drilled to a depth of 30 ft above the mined coal seam near the centerline of the longwall panels. The holes have typical depths of 1,600 to 2,000 ft. The upper half of the hole is cased while the bottom is left open. Three or four holes are drilled per panel and are concentrated mostly in the first half of the panel.

With horizontal degasification, methane is collected by means of horizontal wells drilled into solid blocks of coal (typically before longwall mining) as the mine development progresses (Figure 4) (Mulhern, 1993). Horizontal wells are normally drilled to a depth approximately 90% of the panel width at a spacing interval based on experience. A typical panel in the study area has approximately 20 to 25 wells with a total footage in the range of 7,500 to 10,000 ft.

3.7 Methane Reserves at the JWR No. 5 Mine

An important aspect of the proposed project is the confirmation that sufficient feedstock exists for the demonstration of the reduction of methane emissions by conversion to electric and/or mechanical power. While it has been recognized that the coal seams of the Warrior basin contain significant quantities of methane, the potential for recovering this methane is highly variable. Variations in reservoir properties, recovery methods, and duration of production all contribute to this variability.

Within the oil and gas industry, various analytical techniques and methods have been developed for estimating the potential for recovering hydrocarbons from geologic formations (Haynes, 1993). These methods have been modified to account for the unique properties of coal seam gas reservoirs, but nonetheless the basic principles still apply (Mavor, 1991). The analytical solutions provide a means of estimating total recoverable gas and in some cases the rate of recovery. However, the method of estimating future recovery from coal seams have been primarily applied to the vertical coalbed methane wells not affected by underground mining operations. Little work has been performed in the area of estimating future recovery from other methane capture systems, such as horizontal wells, gob wells, or mine ventilation.

To assess the potential recovery of methane from the JWR No. 5 mine area, different techniques were applied to each of the four methane capture systems. Results of this assessment are an estimate of the future gas production rate and cumulative gas production for the period 1996 through 2010 (the current planned life of the JWR No. 5 mine).

3.7.1 Mine Ventilation System

The potential future production of methane from the JWR No. 5 mine's ventilation system is dependent primarily upon future mining rates and the methane content of the coal that will be mined in the future. Current projections indicate that future mining will proceed at a rate similar to the most recent past. Accordingly, the methane emission rate into the ventilation system should be at a rate similar to that currently encountered. Because of this, it was determined to utilize the current average emission rate as a basis for projecting the future emission rate.

However, current plans also call for an increased use of pre-mining vertical wells within the JWR No. 5 mine area to recover the methane from the coal. This is expected to lead to a decreased level of gas content in the coal, such that when mining of this coal occurs reduced methane emissions will be encountered. Projections of future mining areas and vertical well degasification rates indicate that 1) the mine will begin to enter the area of degasification in about five years; and 2) the vertical wells will recover about 50% of the methane in-place in about 10 years. Based on this, future projections of methane emissions from the mine were modified to account for the reduced methane content of the coal and the expected reduced methane emission rate.

Figure 24 displays the historic methane emission rate that was used as a basis for estimating the near-term future rate of approximately 15 million cubic feet per day. As shown in the figure, the emission rate begins to decline in about 5 years and continues to decline until the year 2007. Emission rate at this time was estimated to be 50% of the original average rate or about

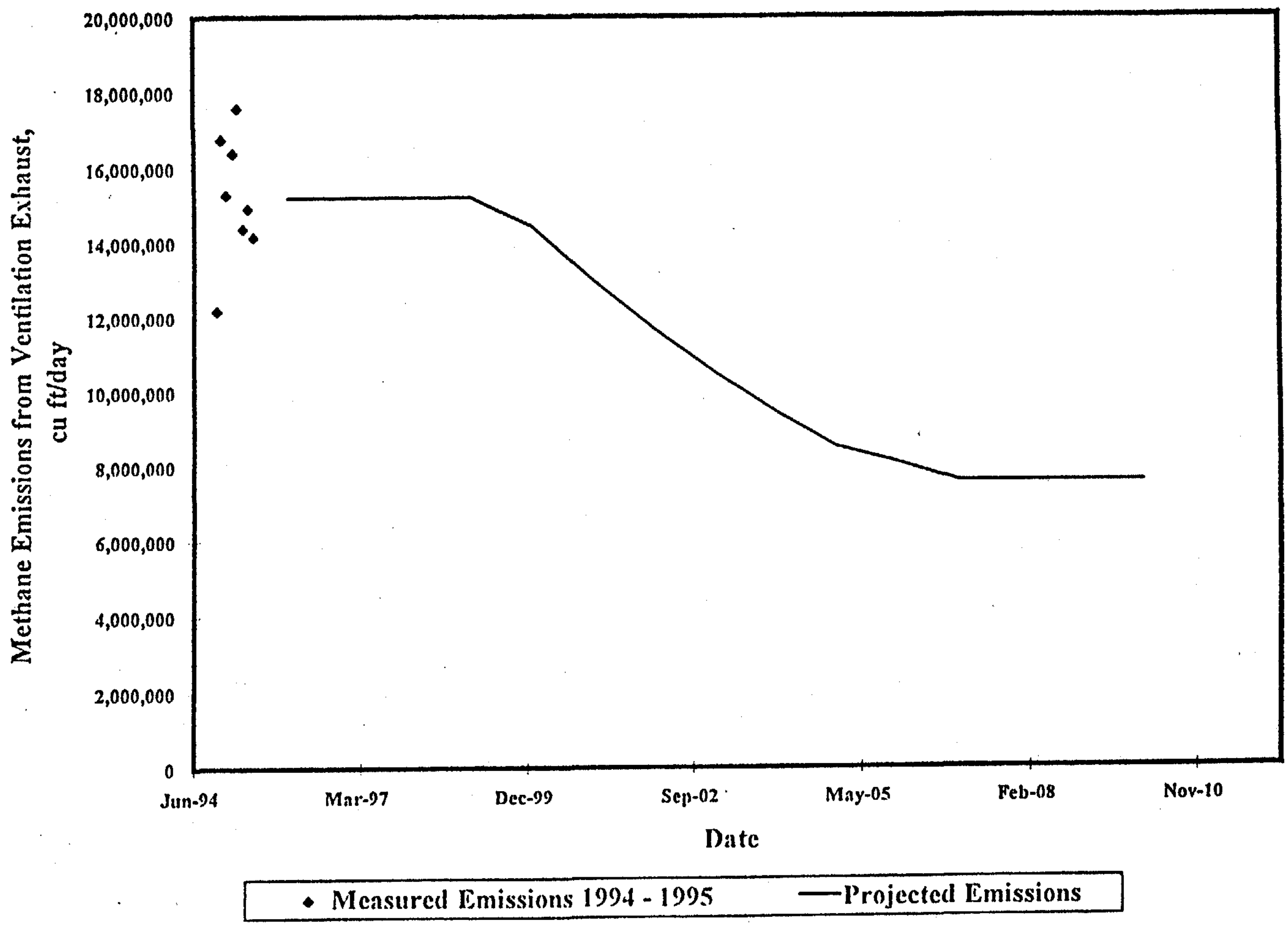

Figure 24. Projected future methane emissions from ventilation exhaust for Mine No. 5 (1996 - 2010).

7.5 million cubic feet per day. The estimated emission rate shown in Figure 24 results in a cumulative emission volume for the 15-year study period of 63.9 billion cubic feet.

3.7.2 Horizontal Degasification Wells

Future production from horizontal wells in the JWR No. 5 mine was estimated also using past historical performance as a basis for projecting future recovery. As with the mine ventilation methane emissions, the horizontal wells will also be impacted by the effect of the vertical well degasification. In addition, with increased pre-mining degasification from these vertical wells, the need to install horizontal wells in the future will decline. Therefore, it was projected that horizontal well production will begin to decline within the next five years and continue to decline throughout the 15-year study period.

Figure 25 shows the historic methane production rate from the horizontal wells at the JWR No. 5 mine and from this an average initial future production rate of approximately 800,000 cubic feet per day was estimated. Because of the effect of vertical well degasification and reduction in the number of horizontal wells used, the average future production rate was reduced at an average rate of 10% per year for the study period, such that by the end of the production projection, horizontal well recovery rate was 200,000 cubic feet per day. Cumulative methane recovery for the 15-year period, based on this projection, was estimated at 2.6 billion cubic feet.

3.7.3 Gob Wells

Using the methodology employed for the mine ventilation system and horizontal wells, the projection of future production from the planned gob wells was determined. The planned vertical well degasification will effectively reduce the methane content not only in the mined coal seam (Mary Lee/Blue Creek) but also in the overlying and underlying coal seams. Because of this, it is expected that the future production rate from the planned gob wells will also decrease. As with the mine ventilation system, current plans expect that within the next five years a production rate decline will be observed such that within ten years the production rate from the future gob wells will be 50% of the current rate.

As shown in Figure 26, near-term future production from the gob wells was estimated to be approximately 5 million cubic feet per day. Production rate decline was forecast to begin in 1999 such that by the year 2006 average production rate from the gob wells at the JWR No. 5 mine was estimated at 2.6 million cubic feet per day. For the 15-year study period, cumulative production from the gob wells was estimated at 22.2 billion cubic feet.

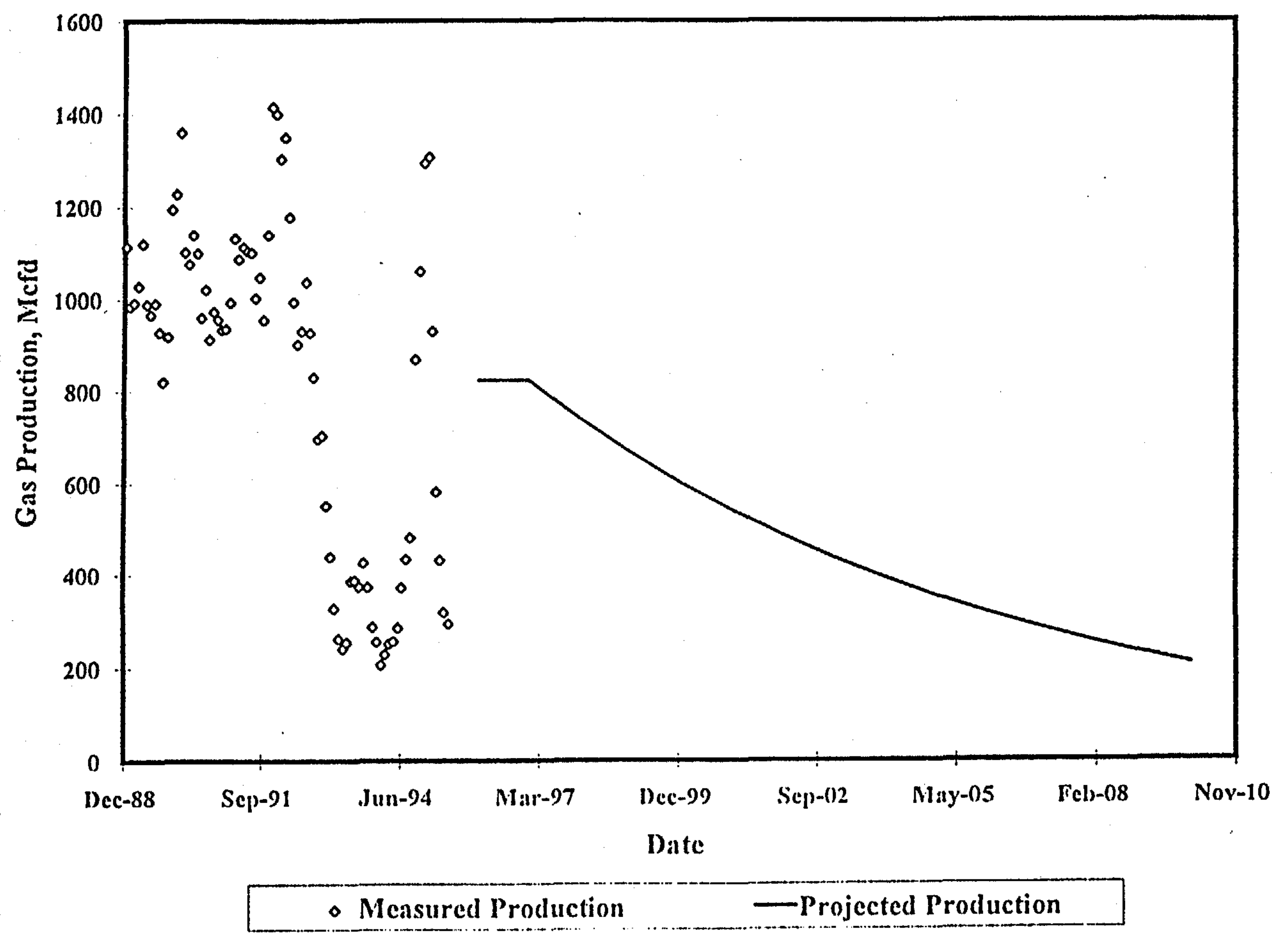

Figure 25. Projected horizontal well production for Mine No. 5 (1996 - 2010).

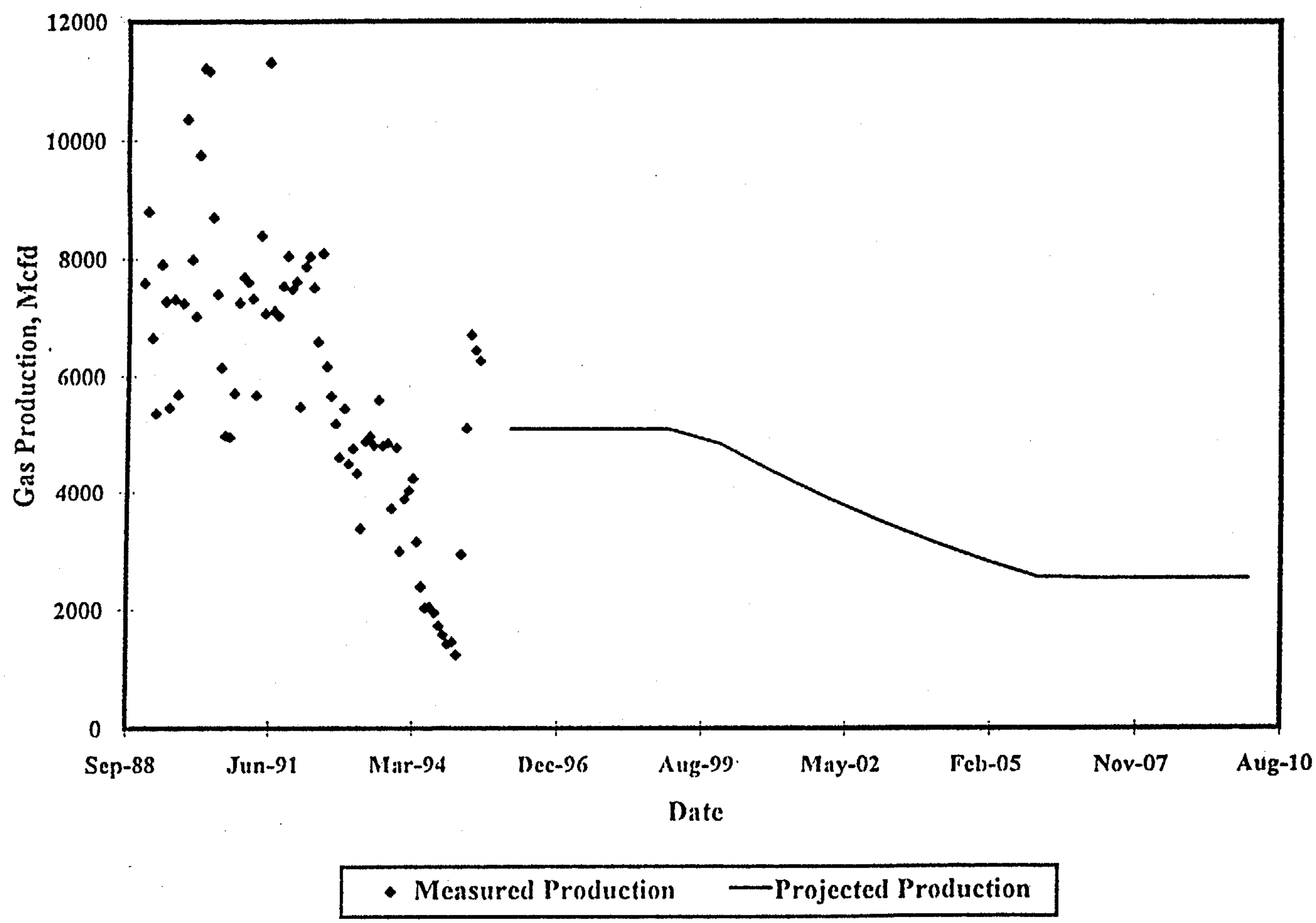

Figure 26. Projected gob well production for Mine No. 5 (1996 - 2010).

3.7.4 Vertical Wells

The projection of future production from vertical wells in advance of mining could not rely upon past experience. Recently improved completion practices and additional targeted reservoirs has resulted in higher production rates from these newer wells. Because of this, a different technique was employed for estimating the future production from the planned vertical well program.

Based on recent production data, a typical production type-curve was developed for a single vertical well within the JWR No. 5 mine area. Figure 27 shows the expected production rate from this single well. As shown, peak production of 300,000 cf per day is expected to occur in the second year of operation followed by a hyperbolic decline leading to a well life of 15 years.

Within the JWR No. 5 mine area, it was projected that at least 100 vertical wells could be drilled for mine degasification (current mine plans call for the installation of at least this many wells). Assuming an installation rate of 25 wells per year for the next four years, 100 wells will be in production by the year 2000. Using the projected single well type-curve and the planned well installation schedule, a projected future production rate from vertical wells was developed, Figure 28. As shown, production peaks in year 1999 at a rate of approximately 22 million cubic feet per day. Projected cumulative production from the planned vertical wells was estimated at 49.2 billion cubic feet.

3.7.5 Summary of Reserves

As discussed above, four different flow streams describe the potential future methane production from the JWR No. 5 mine. For the 15-year study period, cumulative methane recovered by these four systems are summarized in Table 5. This quantity of future recoverable methane resources satisfies the required methane feed stock quantity and production period for the proposed field development phase.

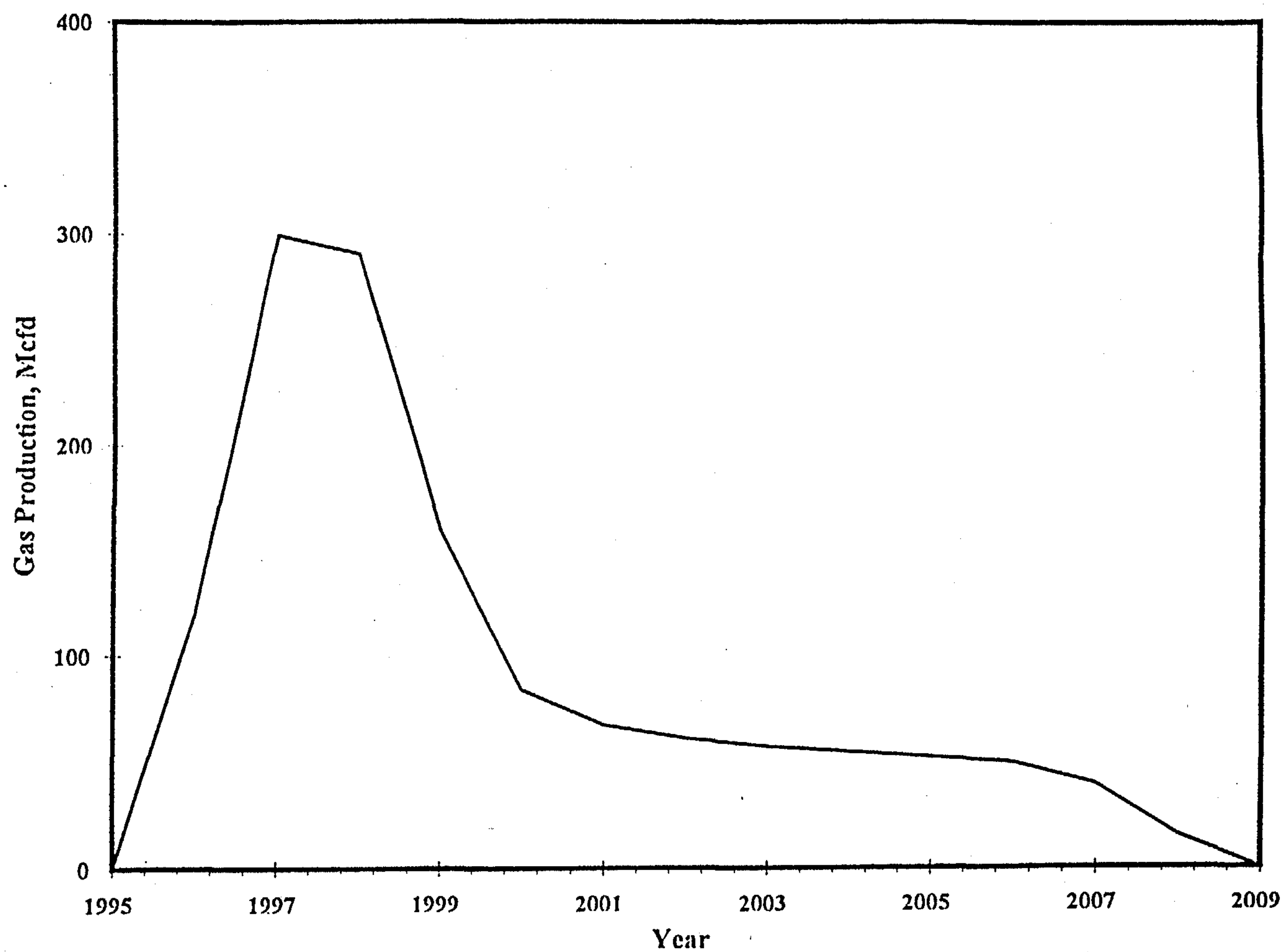

Figure 27. Projected gas production from a single well for Mine No. 5 (1996 - 2009).

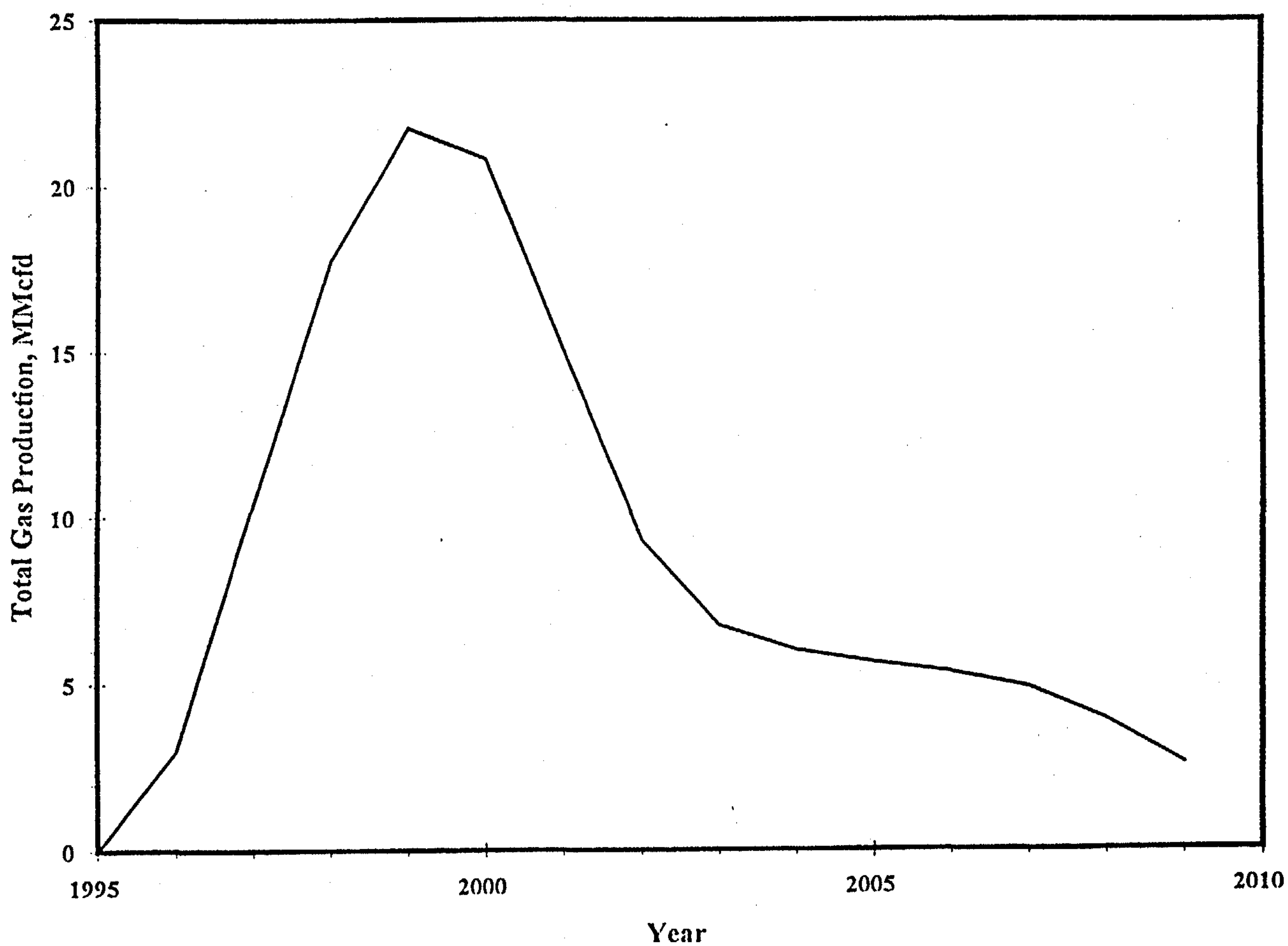

Figure 28. Projected gas production from 100 vertical wells for Mine No. 5 (1996 - 2009).

Table 5 - Reserve Projections for JWR Mine No. 5

RECOVERY SYSTEM	CUMULATIVE RECOVERY, Bcf
Mine Ventilation	63.9
Horizontal Wells	2.6
Gob Wells	22.3
Vertical Wells	49.2
TOTAL	**138.0**

4.0 Phase I — Task 3, Technology Application

A standard 3.4 MW turbine-generator package is now considered to be the best candidate for a demonstration project, since its use will minimize costs and design time. The 3.4 MW size is appropriate to run a single mine fan, and such a unit can be trucked to the site, and placed on a pad, then later moved if the fan is moved. The additional hook-up that will be required includes ducting, an inlet air scrubber, fuel supply, and electrical connection to the existing fan motor.

If a mechanical drive unit is chosen that directly drives the fan, some additional problems will have to be solved. A transmission will have to be designed, the turbine will have to be sited inside the 100-ft limit imposed by MSHA, and the fan will have to have electrical or mechanical back-up power for periods of turbine downtime.

There are a number of other anticipated problems associated with using the mine ventilation air in gas turbine systems. These issues are divided into two groups: those related to the internal gas turbine design features and those associated with the mine-gas-turbine interface. The former problems arose due to the fact that gas turbines have to employ the ventilation air-methane mixture, both as the working fluid, and as part of the supplied fuel.

The interface problems are mostly associated with maintaining the methane concentration in the air stream entering the gas turbine to low levels (at or below 0.5%) and possibly providing a flame-trap between the mine and the gas turbine. The 0.5% upper limit was selected after studies revealed that this concentration level would (probably) not autoignite in any of the interior flow streams of the gas turbine thus solving the bulk of the gas turbine internal problems. The analysis was based on the operating conditions of Solar Turbine, Inc.'s Centaur and Taurus gas turbines. It may be possible to use the Solar Mars engine for mine duty; however its high pressure ratio introduces higher risk factors, particularly in regard to autoignition.

4.1 Objective

The objective of Task 3, Phase I, was to evaluate the potential utilization of low quality mine gases in a gas turbine. In particular, the work concentrated on determining the capability of a gas turbine to combust the methane in the mine ventilation air to produce power, and in so doing remove it from the vented air. This low level of fuel-in-air mixture historically has had methane concentrations between 0.5 and 1%; the latter being the legal limit in the USA for coal mine methane emissions.

4.2 Gas Turbine System Selection

The gas turbine system concept selected for demonstration purposes and its operation are described below. A discussion of the problems and solutions that led to the choice of this particular system is provided in later sections. The system chosen is a low risk approach and could be produced and delivered to a site quickly. Preliminary economic analyses indicate that it should be a viable approach. Detailed economic parameters of the proposed system will be analyzed in Phase II of this program. After these Phase II analyses have been reviewed any necessary modifications to the approach will be made.

The preliminary approach selected for the system design study in Phase II of this program is a gas turbine combined-cycle or cogeneration system with supplementary firing. Such a system would operate on mine ventilation air with up to 0.5% methane. The primary fuel of the turbine would be gas produced by mining operations, either from gob wells or wells drilled in advance of mining. The quality of the gas may vary from pipeline quality to as low as 45% methane. The economic examples set out in this report analyze the operation of the turbine with 100% methane and 80% methane as primary fuel. In this approach, the methane in the ventilation air provides from 10% to 62% of the required thermal energy.

It will be possible to use a lower grade of coal-bed gas if sufficient quantities are available. Solar has developed fuel systems capable of handling methane based gaseous fuels that have low heating values. These systems were developed primarily to handle landfill gases. Typically these gases should have a lower heating value of at least 450 Btu per cubic foot for them to be effective.

Before implementing a demonstration of the combined cycle or cogeneration system a series of preliminary experimental investigative steps have to be undertaken. The first step is to select a demonstrator engine that is small enough to minimizes costs but large enough to provide sufficient power to run some mine equipment. The Centaur or Taurus series of gas turbines meets these requirements and are today, with the knowledge available, the recommended engine system.

The second step will be to investigate on a full size component test rig the effects of 0.5 to 1% methane in air on the Centaur or Taurus combustor performance. In particular the effects of the methane in air on the exit temperature profile and on the emissions of carbon monoxide and unburned hydrocarbons will be determined. In addition the combustor wall and transition section temperatures will be monitored for changes between the baseline case, no methane in the combustor air, and when methane is present. In parallel with these combustor tests, rig evaluations of the cooling performance of the methane in air mixture, on the Centaur or Taurus turbine vanes and blades will be performed. If the results of these rig tests are encouraging, and we believe that this will be the case, an instrumented Centaur or Taurus based system will be produced for a site demonstration (third step).

This demonstrator system will be a simple-cycle gas turbine (no cogeneration or combined cycle) capable of ingesting or fumigating the ventilation air-methane mixture through the gas turbine main compressor. The demonstrator will be a highly instrumented engine system with thermocouples and thermal paint on the hot-end parts. It will be delivered to a site selected by Jim Walter Resources, Inc. where it will undergo rigorous testing for up to 4 months. At present it is planned that this engine system will be fired primarily with high quality coalbed methane. The methane in the ventilation air will supplement the primary fuel thus reducing the amount of high quality methane consumed.

A commercial wet (water) scrubber will be used ahead of the gas turbine to eliminate the coal fines that are found in the saturated ventilation air. This scrubber will also provide a safety factor in that it will act as a flame trap thus isolating the engine from the mine mouth. Once cleaned of particulates the air will be ducted to a methane monitoring station. At this point the methane content of the ventilation air will be monitored continuously. The duct conveying the mine ventilation air will be arranged to merge with a second duct that is open to ambient air. Each of these two ducts will have louver type or equivalent control valves and after merging will feed into the gas turbine inlet. If the concentration of the methane exceeds 0.5% then the louvers on the ambient air duct will open and those on the ventilation air will close. This control will be used to maintain the methane levels at the gas turbine inlet to no more than 0.5%. During startup and shutdown only ambient air will be used by the gas turbine (the louvers on the ventilation air duct will be closed completely).

The exhaust of this system will possibly incorporate a commercially available catalytic oxidation system to eliminate any carbon monoxide or unburned hydrocarbons that may be present. Such emissions are likely because some of the ventilation air will bypass the combustor. As an alternative, a simple supplementary fired cogeneration system may be used with this gas turbine to recover the waste thermal energy. A typical 3 to 5-MW gas turbine arrangement is illustrated in Figure 29. For reference purposes the demonstrator system is shown side-by-side with the mine ventilation system (evasé) in Figure 30.

Once the demonstrator engine has proven its capability of operating on methane-laden ventilation air then the final step, which will be the erection on a suitable site, will be undertaken. This, as mentioned, will be a supplementary fired cogeneration or combined cycle system that is of modular design and which will be able to provide 3 to 15-MW. The supplementary firing in the gas turbine exhaust eliminates the emissions of carbon monoxide and related unburned hydrocarbons thus eliminating the need for a catalytic cleanup system. The demonstrator engine will provide the design information for the gas turbine drivers of this modular combined cycle/cogeneration system. Commercially available afterburners will be used in conjunction with

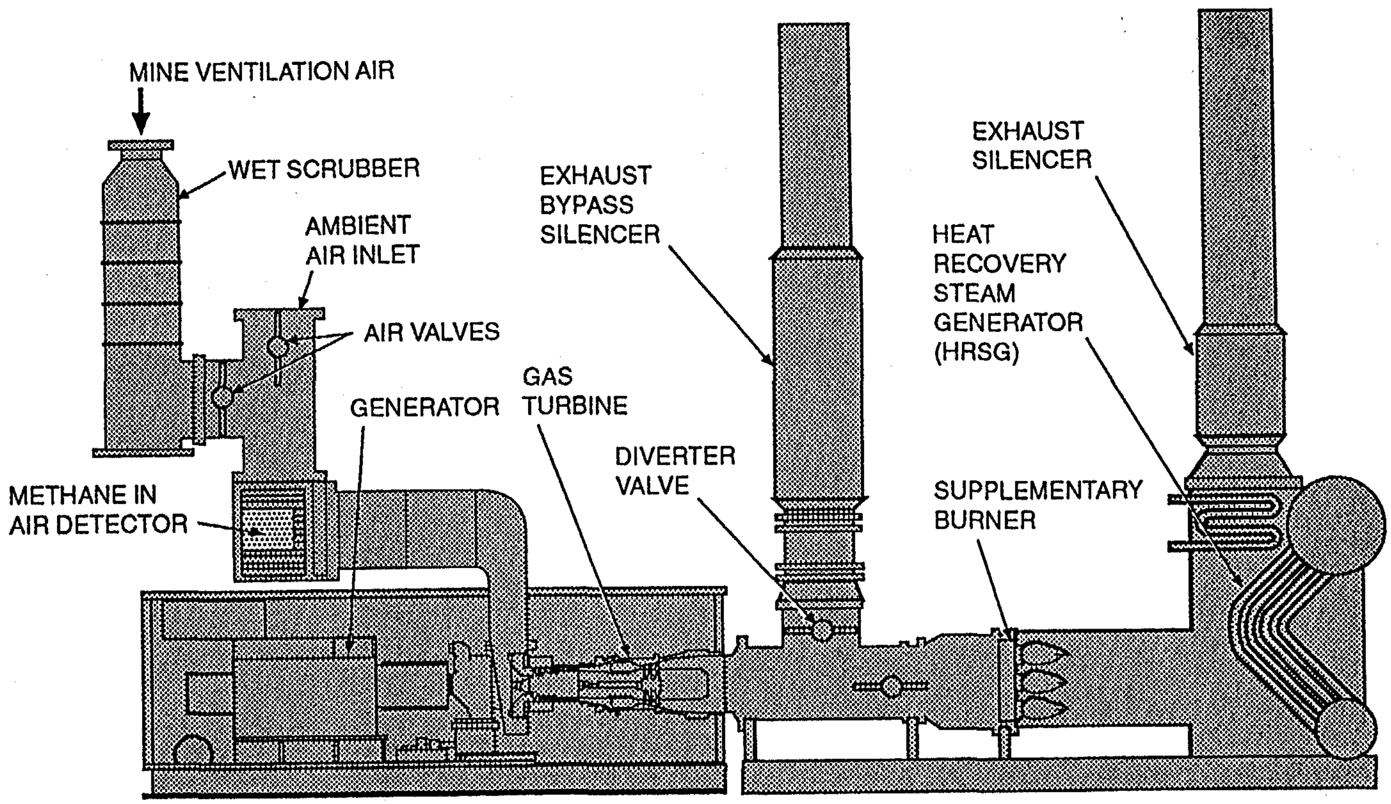

Figure 29. A typical 3-5 MW gas turbine arrangement adapted as a demonstration unit.

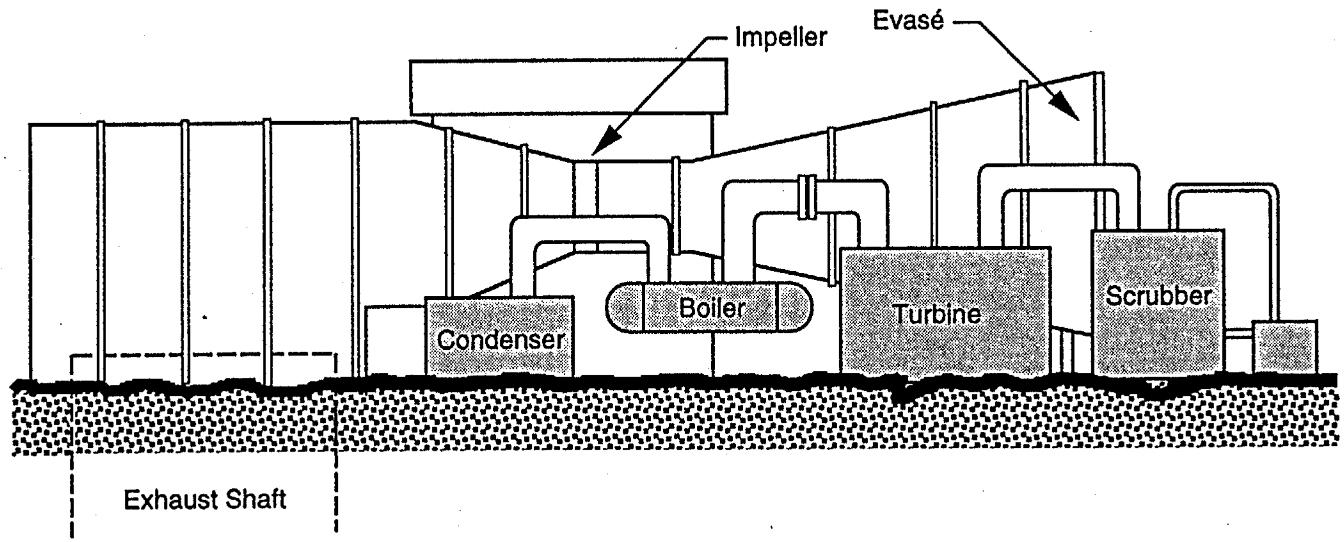

Figure 30. Main fan with turbine demonstration system.

steam generators that can be specified by the customer. (Solar, through an associated company, can supply a sophisticated once-through boiler system of its own design that is tailored to the gas turbine.)

Supplementary fired combined cycle systems based on the Mars engine have been standardized by Solar and Black and Veetch and can be delivered to customers quickly. A system of this type as erected on a customer site is shown in Figure 31. The smaller Centaur units is shown in Figures 32 and 33.

4.3 Gas Turbine Internal Issues and Resolutions

To understand why an upper boundary has been placed on the methane in air concentration, and also why it is considered necessary to test critical components on rigs, some of the more important potential internal gas turbine problems have to be appreciated.

In gas turbines not all of the working fluid passes through the combustor. Some of the fluid (which in this case is an air-methane mixture) is used to pressurize the oil return system and to provide cooling for the hot-end section.

Generally the combustor, the turbine nozzle vanes, the turbine disk and the turbine blades are air cooled. The use of an air-methane mixture for cooling, particularly surface film cooling, typically used in combustors, could potentially cause heating of the surface rather than providing the needed cooling effect. Whether the surface or local hot gas temperatures are sufficient to cause ignition of the methane-air mixture film is not known at the present due to lack of data. From theoretical considerations autoignition is considered to be unlikely, as long as the methane concentration is below 0.5%.

Extrapolating the available data to the conditions likely to be found at the combustor wall surface indicates that the autoignition delay time is on the order of 2.5 milliseconds for 0.5% methane in air. The cooling film will tend to mix into the bulk flow well within this time interval. There is the possibility that under certain conditions (outside wall of a bend) the film may persist (with some mixing) and remain close to the wall. If so, then autoignition could occur and could potentially cause thermal damage.

Other cooling related problems occur when the methane laden air is used to cool, by internal convection, turbine blades or vanes. Because the ventilation air is usually saturated with water the methane and water can react in the presence of nickel alloys to produce hydrogen and carbon monoxide. This mixture autoignites with much shorter delay times than does the methane-air mixture. The autoignition time for the hydrogen mixture is probably less than 1 millisecond at the

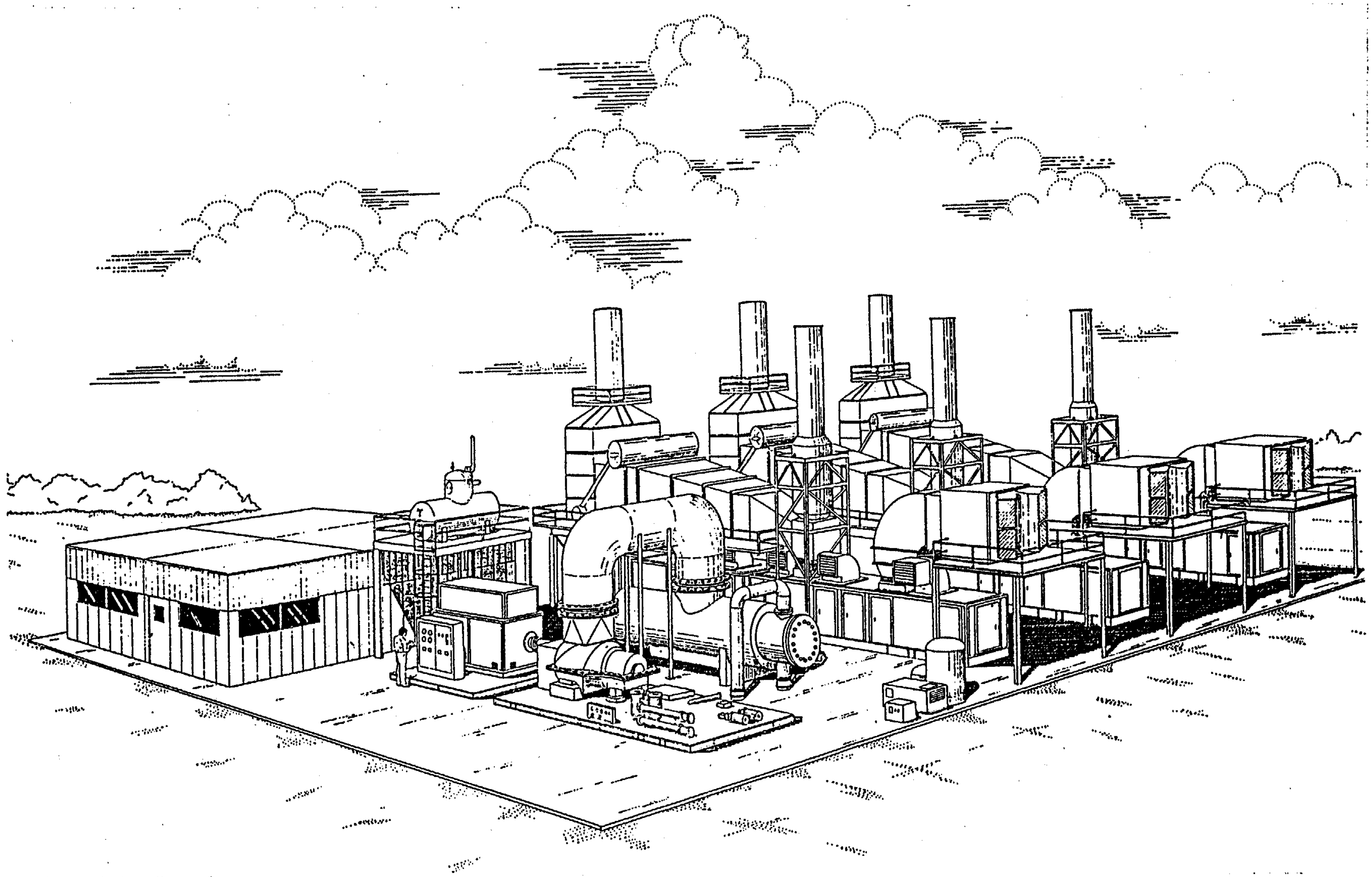

Figure 31. Typical combined cycle installation.

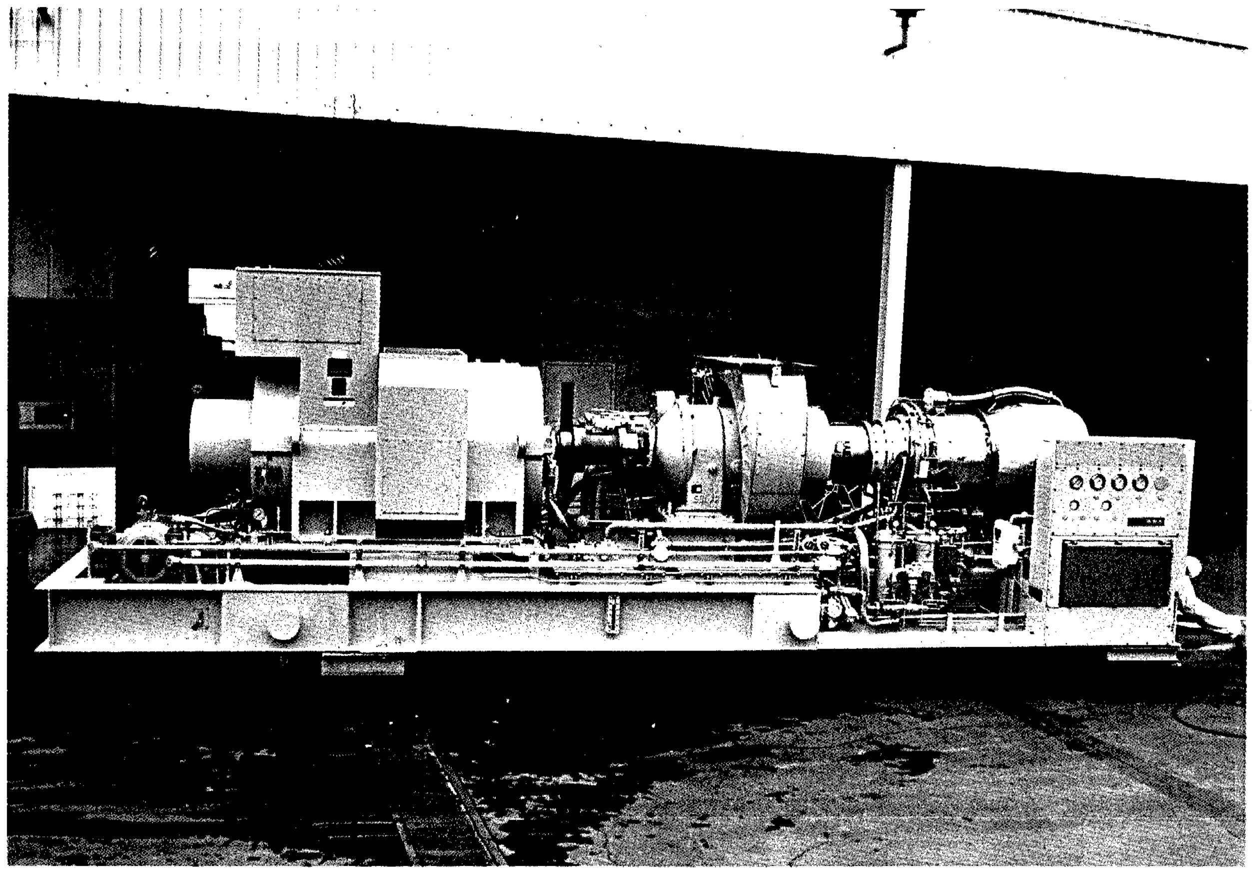

Figure 32. The skid-mounted Centaur 40 turbine unit, ready for installation (consisting of, from left to right, a generator, transmission, and turbine).

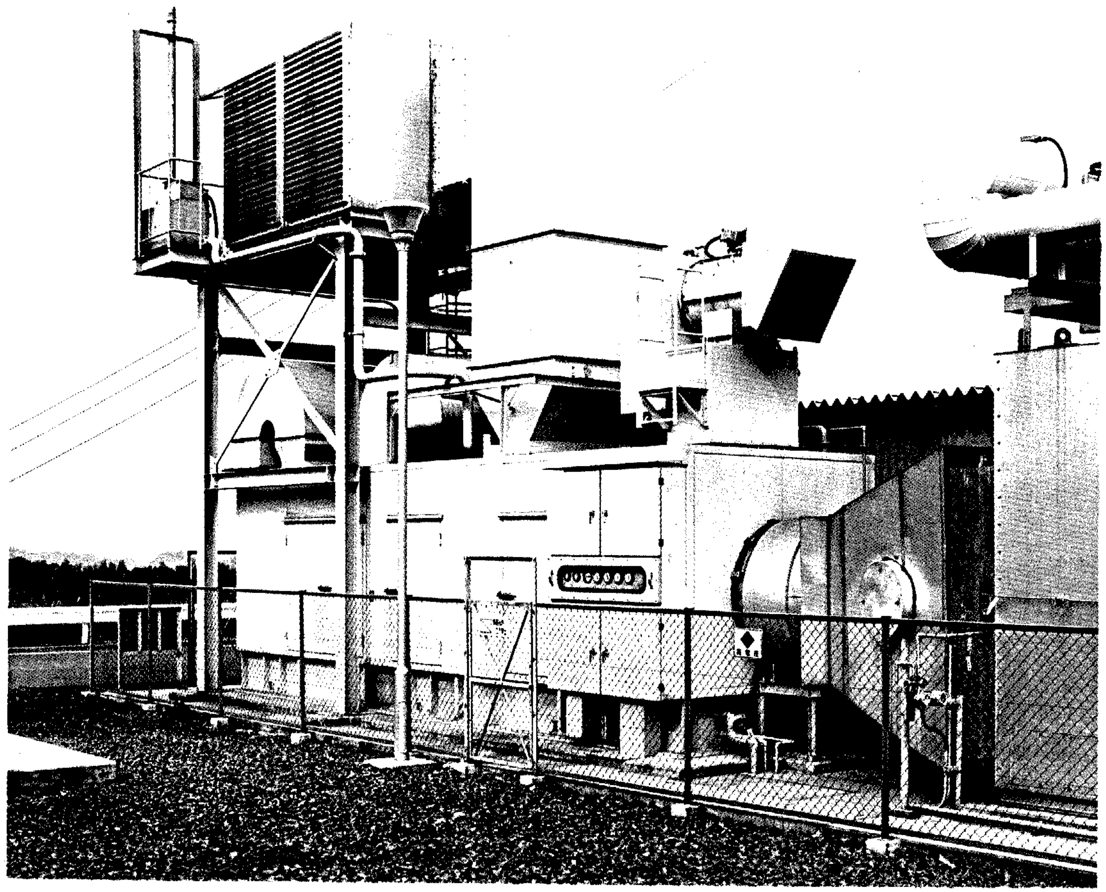

Figure 33. An installed Centaur 40 with a sound-deadening enclosure.

temperature and pressure conditions where the gases exit the first stage turbine blades. The significance of this potential problem is not well understood at the present and further research will have to be performed to determine whether or not the phenomenon will impact turbine operation.

Because some of the methane-laden air bypasses the combustion system there is the strong likelihood of higher than normal carbon monoxide and unburned hydrocarbon emissions. The increase over the condition where there is no methane in the air may be significant. This is why a supplementary fired cogeneration or combined cycle system is recommended as the primary approach. The after-burning in the gas turbine exhaust provides for the combustion of these materials.

The methane laden air is also used to force the oil leaving the engine bearings back to the oil-sump. Methane dissolves in most oils and has a deleterious effect on the oil lubricity. It is possible to remove much of the methane dissolved in the oil using special gas stripper systems. This dissolution and subsequent stripping can concentrate the methane and when added back to the air stream leaving the sump via a vent-pipe could form an explosive mixture. This vent mixture will thus force the introduction of safeguards such as flame traps to ensure that no ignition can take place.

As can be seen from the foregoing discussion the critical factor is the avoidance of autoignition within the engine. The best approach to prevent autoignition is to maintain the methane concentration in the air entering the engine below some critical level. The best estimate today is that this methane concentration has to be at or below 0.5% by volume. To accomplish this, a control system has to be sited between the engine and the ventilation fan (evasé) exhaust duct (see below).

4.4 Interface Issues and Resolutions

Interface problems are largely confined to the control of the methane/air ratio. The methane content of the ventilation air will have to be monitored accurately at the desired low concentration levels, typically less than 2%. A dedicated special purpose gas chromatograph will probably be used to measure these low concentrations. Historically such units have required high levels of support and maintenance but with newer systems it appears that these problems have been largely overcome.

If the ventilation air is found to have a methane concentration higher than 0.5% then fresh ambient air will be added to the ventilation air to dilute the methane level to below the desired 0.5%. To accomplish this dilution, valving will have to be installed ahead of the gas turbine air inlet. Essentially two ducts will be used, one from the fan exhaust and one that opens to allow ambient air to enter. These two ducts will merge into one duct that feeds into the gas turbine inlet. Louvered rectangular valve systems or a swinging door type valve that can cover either one or other of the two inlet ducts will be used to control the ratio of ambient air to ventilation air.

For mine safety reasons it may be necessary to isolate the mine from the gas turbine. This can be accomplished with some form of flame trap. In addition to the flame trap the ventilation air has to be cleaned of the coal fines that are usually entrained in the ventilation air. One approach that can serve as both a particulate removal system and a flame trap is a wet scrubber. These systems use a finely atomized water spray to wet the fine coal particles, thus the particles are mixed with a much larger water drop and are easily removed using inertial techniques such as cyclones.

This separation of the mine from the gas turbine can be accomplished many different ways including systems that are purely mechanical in nature. Any increase in back-pressure on the ventilation air stream will increase the fan power requirements which economically is not desirable. Thus there is a strong driving force to choose the lowest pressure loss particle removal and flame trap system.

4.5 Testing Costs

From the initial studies conducted by Solar it would appear that no new technologies have to be developed. The system considered as the best approach can be constructed entirely from existing commercial systems. This approach is very attractive since development costs, which can be substantial, are avoided. When using the system as described, the primary penalty that has to be paid is that a methane gas compressor has to be installed to pump the primary fuel to a pressure high enough to allow it to be injected into the combustor. This requirement increases the initial cost of the system and also increases operating costs due to the power requirements to compress the methane gas.

There is a secondary economic penalty that has been identified and this is related to technological risk. Because of unknowns in the residence times of the flow streams that do not enter the primary zone of the combustor and of those used in vane and blade cooling, rig tests will have to be conducted. Solar is confident that any problems identified during these tests will be readily resolved. These tests will be part of the proposed Phase III.

Two sets of tests are considered to be required to provide the necessary confidence to proceed with engine demonstration tests. The first rig test set will involve operating a Centaur or Taurus combustor at full-load conditions with and without methane in the main air stream. Any differences in wall temperatures, exit temperature profile, and emissions between the different sets of conditions will be noted. Tests will probably be run with zero methane in the air, and then with concentrations of 0.3%, 0.5%, and 1.0% methane in air respectively. Possible autoignition of the methane-air mixture at or near the wall of the combustor would be discovered through increases in wall temperatures when compared with the zero methane case. Partial combustion of the methane may change the temperature profile leaving the combustor. It is important for the profile to have low temperatures at the nozzle vane root and at the turbine blade platform or disk rim. Any changes in the lower temperature part of the profile will be carefully monitored.

In parallel with the combustor tests, evaluations of the effects of methane-in-air on turbine vane and blade cooling performance will be conducted. Tests will be conducted using full size engine vanes or blades to determine the effects of having methane in the cooling air. The vanes or blades would be maintained in a furnace or rig at the normal engine operating temperatures. Air with and without methane would be introduced into the cooling passages and thermocouple and/or thermal paint readings of the surface temperatures will be recorded. Any autoignition and subsequent combustion of the methane would be determined from the surface temperature measurements. The cooling gases will also be analyzed as they exit from the blade to determine if any reforming of the methane to hydrogen and carbon monoxide has taken place. The mixture of hydrogen and carbon monoxide has a much shorter ignition delay time than methane and could possibly cause problems at the trailing edge of the turbine blade.

These tests are likely to have a cost to the program. This is the only economic technology penalty that has been identified as impacting the development of a mine ventilation air engine system. The costs incurred during the engine system demonstration are deemed to be part of the normal development activities. The rig tests are over and above these engine demonstration tests and are thus assessed as a penalty to the program. These costs, which can be considered to be insurance, are reasonable when they are compared to the total system costs.

4.6 Economic Assessment

The results of the economic analysis are presented in Tables 6 through 16. These analyses are based upon the Solar Turbines Centaur Model 40. The factors for unit cost, maintenance cost, unit availability, power output, and fuel usage are from data provided by Solar Turbines. The estimates for fuel gas price, gob gas LOE (lease operating expenses), royalties, and severance are based upon experience in the Black Warrior Basin. Explanation of line items in the tables follows.

4.6.1 Glossary of Terms Used in Tables 6-16

Cost of Unit. The cost stated in "Assumptions" is the purchase price of the unit, transportation to the site, site preparation, installation, and commissioning. The cost of the

Table 6 - Economic Analysis, 3.4 MW Gas-fired, Mine-mouth Power Turbine

Base Case

Assumptions:			
Cost of unit	$1,700,000	Inflation factor	3%
Maintenance cost ($/kwh)	$0.0035	Unit availability (hrs/yr)	8,000
Fuel gas price ($/mcf)	$1.75	Elec. power value or cost ($/kwh)	$0.042
Gob gas LOE	$0.31	Power output (MW)	3.451
Royalty (as % of mkt val)	12.5%	Fuel useage (mcf/hr)	42.6
Severance tax (as % of mkt val)	5.0%	Percent of energy value from fumigant	11.2%
Depreciation	7 year, DDB	Fuel quality of primary fuel (% methane)	80.0%

Results: (year of operation)	1	2	3	4	5	6	7	8
Annual power output (kwh)	27,608,000	$27,608,000	$27,608,000	$27,608,000	$27,608,000	$27,608,000	$27,608,000	$27,608,000
Revenue	$1,159,536	$1,194,322	$1,230,152	$1,267,056	$1,305,068	$1,344,220	$1,384,547	$1,426,083
Fuel cost	($117,269)	($120,787)	($124,411)	($128,143)	($131,988)	($135,947)	($140,026)	($144,226)
Royalty & severance tax (gob gas)	($76,263)	($78,551)	($80,907)	($83,334)	($85,835)	($88,410)	($91,062)	($93,794)
Royalty & severance tax (fumigant)	($9,619)	($9,907)	($10,205)	($10,511)	($10,826)	($11,151)	($11,485)	($11,830)
Maintenance cost	($96,628)	($99,527)	($102,513)	($105,588)	($108,756)	($112,018)	($115,379)	($118,840)
Total cost	($299,779)	($308,772)	($318,035)	($327,576)	($337,404)	($347,526)	($357,952)	($368,690)
Net revenue	$859,757	$885,550	$912,116	$939,480	$967,664	$996,694	$1,026,595	$1,057,393
Depreciation	($485,714)	($346,939)	($247,813)	($177,010)	($126,435)	($90,311)	($64,508)	$0
Taxable income	$374,043	$538,611	$664,303	$762,470	$841,229	$906,383	$962,087	$1,057,393
Income tax (Fed & State)	($134,655)	($193,900)	($239,149)	($274,489)	($302,842)	($326,298)	($346,351)	($380,661)
Income after taxes	$239,387	$344,711	$425,154	$487,981	$538,386	$580,085	$615,736	$676,731
Net cash flow	$725,102	$691,650	$672,967	$664,991	$664,822	$670,396	$680,244	$676,731
Cumulative net cash flow	$725,102	$1,416,752	$2,089,719	$2,754,709	$3,419,531	$4,089,927	$4,770,171	$5,446,902

Net Present Value	**$1,769,635**
Internal Rate of Return	**37.5%**

Methane Emission Reductions (mcf/yr)	
Noncommercial gob gas	302,630
Ventilation gas	38,170
Total	**340,800**

Table 7 - Economic Analysis, 3.4 MW Gas-fired, Mine-mouth Power Turbine

Base Case with no royalty or severance tax on fumigant

Assumptions:			
Cost of unit	$1,700,000	Inflation factor	3%
Maintenance cost ($/kwh)	$0.0035	Unit availability (hrs/yr)	8,000
Fuel gas price ($/mcf)	$1.75	Elec. power value or cost ($/kwh)	$0.042
Gob gas LOE	$0.31	Power output (MW)	3.451
Royalty (as % of mkt val)	12.5%	Fuel useage (mcf/hr)	42.6
Severance tax (as % of mkt val)	5.0%	Percent of energy value from fumigant	11.2%
Depreciation	7 year, DDB	Fuel quality of primary fuel (% methane)	80.0%

Results: (year of operation)	1	2	3	4	5	6	7	8
Annual power output (kwh)	27,608,000	$27,608,000	$27,608,000	$27,608,000	$27,608,000	$27,608,000	$27,608,000	$27,608,000
Revenue	$1,159,536	$1,194,322	$1,230,152	$1,267,056	$1,305,068	$1,344,220	$1,384,547	$1,426,083
Fuel cost	($117,269)	($120,787)	($124,411)	($128,143)	($131,988)	($135,947)	($140,026)	($144,226)
Royalty & severance tax (gob gas)	($76,263)	($78,551)	($80,907)	($83,334)	($85,835)	($88,410)	($91,062)	($93,794)
Royalty & severance tax (fumigant)	$0	$0	$0	$0	$0	$0	$0	$0
Maintenance cost	($96,628)	($99,527)	($102,513)	($105,588)	($108,756)	($112,018)	($115,379)	($118,840)
Total cost	($290,160)	($298,865)	($307,831)	($317,066)	($326,578)	($336,375)	($346,466)	($356,860)
Net revenue	$869,376	$895,457	$922,321	$949,990	$978,490	$1,007,845	$1,038,080	$1,069,223
Depreciation	($485,714)	($346,939)	($247,813)	($177,010)	($126,435)	($90,311)	($64,508)	$0
Taxable income	$383,662	$548,518	$674,507	$772,981	$852,055	$917,534	$973,572	$1,069,223
Income tax (Fed & State)	($138,118)	($197,467)	($242,823)	($278,273)	($306,740)	($330,312)	($350,486)	($384,920)
Income after taxes	$245,543	$351,052	$431,685	$494,708	$545,315	$587,222	$623,086	$684,302
Net cash flow	$731,258	$697,991	$679,498	$671,717	$671,750	$677,533	$687,594	$684,302
Cumulative net cash flow	$731,258	$1,429,248	$2,108,746	$2,780,464	$3,452,214	$4,129,747	$4,817,341	$5,501,644

Net Present Value	**$1,802,337**
Internal Rate of Return	**37.9%**

Methane Emission Reductions (mcf/yr)	
Noncommercial gob gas	302,630
Ventilation gas	38,170
Total	**340,800**

Table 8 - Economic Analysis, 3.4 MW Gas-fired, Mine-mouth Power Turbine

Case # 2, Base Case with low TRIT

Assumptions:			
Cost of unit	$1,700,000	Inflation factor	3%
Maintenance cost ($/kwh)	$0.0035	Unit availability (hrs/yr)	8,000
Fuel gas price ($/mcf)	$1.75	Elec. power value or cost ($/kwh)	$0.045
Gob gas LOE	$0.31	Power output (MW)	2.5
Royalty (as % of mkt val)	12.5%	Fuel useage (mcf/hr)	42.6
Severance tax (as % of mkt val)	5.0%	Percent of energy value from fumigant	30.4%
Depreciation	7 year, DDB	Fuel quality of primary fuel (% methane)	80.0%

Results: (year of operation)	1	2	3	4	5	6	7	8
Annual power output (kwh)	20,000,000	$20,000,000	$20,000,000	$20,000,000	$20,000,000	$20,000,000	$20,000,000	$20,000,000
Revenue	$900,000	$927,000	$954,810	$983,454	$1,012,958	$1,043,347	$1,074,647	$1,106,886
Fuel cost	($91,914)	($94,671)	($97,511)	($100,437)	($103,450)	($106,553)	($109,750)	($113,042)
Royalty & severance tax (gob gas)	($59,774)	($61,567)	($63,414)	($65,316)	($67,276)	($69,294)	($71,373)	($73,514)
Royalty & severance tax (fumigant)	($26,108)	($26,891)	($27,698)	($28,529)	($29,385)	($30,266)	($31,174)	($32,110)
Maintenance cost	($70,000)	($72,100)	($74,263)	($76,491)	($78,786)	($81,149)	($83,584)	($86,091)
Total cost	($247,795)	($255,229)	($262,886)	($270,773)	($278,896)	($287,263)	($295,881)	($304,757)
Net revenue	$652,205	$671,771	$691,924	$712,682	$734,062	$756,084	$778,766	$802,129
Depreciation	($485,714)	($346,939)	($247,813)	($177,010)	($126,435)	($90,311)	($64,508)	$0
Taxable income	$166,490	$324,832	$444,110	$535,672	$607,627	$665,773	$714,259	$802,129
Income tax (Fed & State)	($59,937)	($116,940)	($159,880)	($192,842)	($218,746)	($239,678)	($257,133)	($288,767)
Income after taxes	$106,554	$207,892	$284,231	$342,830	$388,881	$426,095	$457,125	$513,363
Net cash flow	$592,268	$554,831	$532,044	$519,840	$515,316	$516,406	$521,633	$513,363
Cumulative net cash flow	$592,268	$1,147,099	$1,679,143	$2,198,983	$2,714,300	$3,230,705	$3,752,339	$4,265,702

Net Present Value	**$1,063,991**
Internal Rate of Return	**27.5%**

Methane Emission Reductions (mcf/yr)	
Noncommercial gob gas	237,197
Ventilation gas	103,603
Total	**340,800**

Table 9 - Economic Analysis, 3.4 MW Gas-fired, Mine-mouth Power Turbine
Case # 2 with no royalty or severance tax on fumigant

Assumptions:			
Cost of unit	$1,700,000	Inflation factor	3%
Maintenance cost ($/kwh)	$0.0035	Unit availability (hrs/yr)	8,000
Fuel gas price ($/mcf)	$1.75	Elec. power value or cost ($/kwh)	$0.045
Gob gas LOE	$0.31	Power output (MW)	2.5
Royalty (as % of mkt val)	12.5%	Fuel useage (mcf/hr)	42.6
Severance tax (as % of mkt val)	5.0%	Percent of energy value from fumigant	30.4%
Depreciation	7 year, DDB	Fuel quality of primary fuel (% methane)	80.0%

Results: (year of operation)	1	2	3	4	5	6	7	8
Annual power output (kwh)	20,000,000	$20,000,000	$20,000,000	$20,000,000	$20,000,000	$20,000,000	$20,000,000	$20,000,000
Revenue	$900,000	$927,000	$954,810	$983,454	$1,012,958	$1,043,347	$1,074,647	$1,106,886
Fuel cost	($91,914)	($94,671)	($97,511)	($100,437)	($103,450)	($106,553)	($109,750)	($113,042)
Royalty & severance tax (gob gas)	($59,774)	($61,567)	($63,414)	($65,316)	($67,276)	($69,294)	($71,373)	($73,514)
Royalty & severance tax (fumigant)	$0	$0	$0	$0	$0	$0	$0	$0
Maintenance cost	($70,000)	($72,100)	($74,263)	($76,491)	($78,786)	($81,149)	($83,584)	($86,091)
Total cost	($221,687)	($228,338)	($235,188)	($242,244)	($249,511)	($256,996)	($264,706)	($272,647)
Net revenue	$678,313	$698,662	$719,622	$741,211	$763,447	$786,350	$809,941	$834,239
Depreciation	($485,714)	($346,939)	($247,813)	($177,010)	($126,435)	($90,311)	($64,508)	$0
Taxable income	$192,598	$351,723	$471,808	$564,201	$637,011	$696,039	$745,433	$834,239
Income tax (Fed & State)	($69,335)	($126,620)	($169,851)	($203,112)	($229,324)	($250,574)	($268,356)	($300,326)
Income after taxes	$123,263	$225,103	$301,957	$361,089	$407,687	$445,465	$477,077	$533,913
Net cash flow	$608,977	$572,042	$549,771	$538,098	$534,123	$535,776	$541,585	$533,913
Cumulative net cash flow	$608,977	$1,181,019	$1,730,790	$2,268,888	$2,803,011	$3,338,787	$3,880,372	$4,414,285

Net Present Value	**$1,152,754**
Internal Rate of Return	**28.8%**

Methane Emission Reductions (mcf/yr)	
Noncommercial gob gas	237,197
Ventilation gas	103,603
Total	**340,800**

Table 10 - Economic Analysis, 3.4 MW Gas-fired, Mine-mouth Power Turbine

Case # 3, Base Case with primary fuel of 100% methane

Assumptions:			
Cost of unit	$1,700,000	Inflation factor	3%
Maintenance cost ($/kwh)	$0.0035	Unit availability (hrs/yr)	8,000
Fuel gas price ($/mcf)	$1.75	Elec. power value or cost ($/kwh)	$0.042
Gob gas LOE	$0.31	Power output (MW)	3.4
Royalty (as % of mkt val)	12.5%	Fuel useage (mcf/hr)	42.6
Severance tax (as % of mkt val)	5.0%	Percent of energy value from fumigant	10.0%
Depreciation	7 year, DDB	Fuel quality of primary fuel (% methane)	100.0%

Results: (year of operation)	1	2	3	4	5	6	7	8
Annual power output (kwh)	27,200,000	$27,200,000	$27,200,000	$27,200,000	$27,200,000	$27,200,000	$27,200,000	$27,200,000
Revenue	$1,142,400	$1,176,672	$1,211,972	$1,248,331	$1,285,781	$1,324,355	$1,364,085	$1,405,008
Fuel cost	($95,083)	($97,936)	($100,874)	($103,900)	($107,017)	($110,227)	($113,534)	($116,940)
Royalty & severance tax (gob gas)	($77,293)	($79,612)	($82,001)	($84,461)	($86,994)	($89,604)	($92,292)	($95,061)
Royalty & severance tax (fumigant)	($8,588)	($8,846)	($9,111)	($9,385)	($9,666)	($9,956)	($10,255)	($10,562)
Maintenance cost	($95,200)	($98,056)	($100,998)	($104,028)	($107,148)	($110,363)	($113,674)	($117,084)
Total cost	($276,165)	($284,450)	($292,983)	($301,773)	($310,826)	($320,151)	($329,755)	($339,648)
Net revenue	$866,235	$892,222	$918,989	$946,559	$974,955	$1,004,204	$1,034,330	$1,065,360
Depreciation	($485,714)	($346,939)	($247,813)	($177,010)	($126,435)	($90,311)	($64,508)	$0
Taxable income	$380,521	$545,283	$671,176	$769,549	$848,520	$913,893	$969,822	$1,065,360
Income tax (Fed & State)	($136,988)	($196,302)	($241,623)	($277,038)	($305,467)	($329,001)	($349,136)	($383,530)
Income after taxes	$243,533	$348,981	$429,552	$492,511	$543,053	$584,892	$620,686	$681,830
Net cash flow	$729,248	$695,920	$677,366	$669,521	$669,488	$675,203	$685,194	$681,830
Cumulative net cash flow	$729,248	$1,425,168	$2,102,534	$2,772,055	$3,441,543	$4,116,745	$4,801,939	$5,483,770

Net Present Value	**$1,791,659**
Internal Rate of Return	**37.8%**

Methane Emission Reductions (mcf/yr)	
Noncommercial gob gas	0
Ventilation gas	34,080
Total	**34,080**

Table 11 - Economic Analysis, 3.4 MW Gas-fired, Mine-mouth Power Turbine
Case # 3 with no royalty or severance tax on fumigant

Assumptions:			
Cost of unit	$1,700,000	Inflation factor	3%
Maintenance cost ($/kwh)	$0.0035	Unit availability (hrs/yr)	8,000
Fuel gas price ($/mcf)	$1.75	Elec. power value or cost ($/kwh)	$0.042
Gob gas LOE	$0.31	Power output (MW)	3.4
Royalty (as % of mkt val)	12.5%	Fuel useage (mcf/hr)	42.6
Severance tax (as % of mkt val)	5.0%	Percent of energy value from fumigant	10.0%
Depreciation	7 year, DDB	Fuel quality of primary fuel (% methane)	100.0%

Results: (year of operation)	1	2	3	4	5	6	7	8
Annual power output (kwh)	27,200,000	$27,200,000	$27,200,000	$27,200,000	$27,200,000	$27,200,000	$27,200,000	$27,200,000
Revenue	$1,142,400	$1,176,672	$1,211,972	$1,248,331	$1,285,781	$1,324,355	$1,364,085	$1,405,008
Fuel cost	($95,083)	($97,936)	($100,874)	($103,900)	($107,017)	($110,227)	($113,534)	($116,940)
Royalty & severance tax (gob gas)	($77,293)	($79,612)	($82,001)	($84,461)	($86,994)	($89,604)	($92,292)	($95,061)
Royalty & severance tax (fumigant)	$0	$0	$0	$0	$0	$0	$0	$0
Maintenance cost	($95,200)	($98,056)	($100,998)	($104,028)	($107,148)	($110,363)	($113,674)	($117,084)
Total cost	($267,577)	($275,604)	($283,872)	($292,388)	($301,160)	($310,195)	($319,501)	($329,086)
Net revenue	$874,823	$901,068	$928,100	$955,943	$984,621	$1,014,160	$1,044,585	$1,075,922
Depreciation	($485,714)	($346,939)	($247,813)	($177,010)	($126,435)	($90,311)	($64,508)	$0
Taxable income	$389,109	$554,129	$680,287	$778,934	$858,186	$923,849	$980,077	$1,075,922
Income tax (Fed & State)	($140,079)	($199,487)	($244,903)	($280,416)	($308,947)	($332,586)	($352,828)	($387,332)
Income after taxes	$249,030	$354,643	$435,383	$498,517	$549,239	$591,263	$627,249	$688,590
Net cash flow	$734,744	$701,582	$683,197	$675,527	$675,674	$681,574	$691,757	$688,590
Cumulative net cash flow	$734,744	$1,436,326	$2,119,523	$2,795,050	$3,470,724	$4,152,298	$4,844,056	$5,532,646

Net Present Value	**$1,820,858**
Internal Rate of Return	**38.2%**

Methane Emission Reductions (mcf/yr)	
Noncommercial gob gas	0
Ventilation gas	34,080
Total	**34,080**

Table 12 - Economic Analysis, 3.4 MW Gas-fired, Mine-mouth Power Turbine
Case # 4, recuperated engine at low TRIT with primary fuel of 100% methane

Assumptions:			
Cost of unit	$2,125,000	Inflation factor	3%
Maintenance cost ($/kwh)	$0.0035	Unit availability (hrs/yr)	8,000
Fuel gas price ($/mcf)	$1.75	Elec. power value or cost ($/kwh)	$0.048
Gob gas LOE	$0.31	Power output (MW)	2.5
Royalty (as % of mkt val)	12.5%	Fuel useage (mcf/hr)	42.6
Severance tax (as % of mkt val)	5.0%	Percent of energy value from fumigant	55.0%
Depreciation	7 year, DDB	Fuel quality of primary fuel (% methane)	100.0%

Results: (year of operation)	1	2	3	4	5	6	7	8
Annual power output (kwh)	20,000,000	$20,000,000	$20,000,000	$20,000,000	$20,000,000	$20,000,000	$20,000,000	$20,000,000
Revenue	$960,000	$988,800	$1,018,464	$1,049,018	$1,080,488	$1,112,903	$1,146,290	$1,180,679
Fuel cost	($47,542)	($48,968)	($50,437)	($51,950)	($53,508)	($55,114)	($56,767)	($58,470)
Royalty & severance tax (gob gas)	($38,647)	($39,806)	($41,000)	($42,230)	($43,497)	($44,802)	($46,146)	($47,531)
Royalty & severance tax (fumigant)	($47,235)	($48,652)	($50,111)	($51,615)	($53,163)	($54,758)	($56,401)	($58,093)
Maintenance cost	($70,000)	($72,100)	($74,263)	($76,491)	($78,786)	($81,149)	($83,584)	($86,091)
Total cost	($203,423)	($209,526)	($215,812)	($222,286)	($228,955)	($235,823)	($242,898)	($250,185)
Net revenue	$756,577	$779,274	$802,652	$826,732	$851,534	$877,080	$903,392	$930,494
Depreciation	($607,143)	($433,673)	($309,767)	($221,262)	($158,044)	($112,889)	($80,635)	$0
Taxable income	$149,434	$345,601	$492,886	$605,470	$693,490	$764,191	$822,757	$930,494
Income tax (Fed & State)	($53,796)	($124,416)	($177,439)	($217,969)	($249,656)	($275,109)	($296,193)	($334,978)
Income after taxes	$95,638	$221,184	$315,447	$387,501	$443,833	$489,082	$526,565	$595,516
Net cash flow	$702,781	$654,858	$625,214	$608,763	$601,878	$601,971	$607,200	$595,516
Cumulative net cash flow	$702,781	$1,357,638	$1,982,852	$2,591,615	$3,193,492	$3,795,463	$4,402,663	$4,998,179

Net Present Value	**$1,130,490**
Internal Rate of Return	**25.1%**

Methane Emission Reductions (mcf/yr)	
Noncommercial gob gas	0
Ventilation gas	187,440
Total	**187,440**

Table 13 - Economic Analysis, 3.4 MW Gas-fired, Mine-mouth Power Turbine
Case # 4 with no royalty or severance tax on fumigant

Assumptions:			
Cost of unit	$2,125,000	Inflation factor	3%
Maintenance cost ($/kwh)	$0.0035	Unit availability (hrs/yr)	8,000
Fuel gas price ($/mcf)	$1.75	Elec. power value or cost ($/kwh)	$0.048
Gob gas LOE	$0.31	Power output (MW)	2.5
Royalty (as % of mkt val)	12.5%	Fuel useage (mcf/hr)	42.6
Severance tax (as % of mkt val)	5.0%	Percent of energy value from fumigant	55.0%
Depreciation	7 year, DDB	Fuel quality of primary fuel (% methane)	100.0%

Results: (year of operation)	1	2	3	4	5	6	7	8
Annual power output (kwh)	20,000,000	$20,000,000	$20,000,000	$20,000,000	$20,000,000	$20,000,000	$20,000,000	$20,000,000
Revenue	$960,000	$988,800	$1,018,464	$1,049,018	$1,080,488	$1,112,903	$1,146,290	$1,180,679
Fuel cost	($47,542)	($48,968)	($50,437)	($51,950)	($53,508)	($55,114)	($56,767)	($58,470)
Royalty & severance tax (gob gas)	($38,647)	($39,806)	($41,000)	($42,230)	($43,497)	($44,802)	($46,146)	($47,531)
Royalty & severance tax (fumigant)	$0	$0	$0	$0	$0	$0	$0	$0
Maintenance cost	($70,000)	($72,100)	($74,263)	($76,491)	($78,786)	($81,149)	($83,584)	($86,091)
Total cost	($156,188)	($160,874)	($165,700)	($170,671)	($175,791)	($181,065)	($186,497)	($192,092)
Net revenue	$803,812	$827,926	$852,764	$878,347	$904,697	$931,838	$959,793	$988,587
Depreciation	($607,143)	($433,673)	($309,767)	($221,262)	($158,044)	($112,889)	($80,635)	$0
Taxable income	$196,669	$394,253	$542,997	$657,085	$746,653	$818,949	$879,158	$988,587
Income tax (Fed & State)	($70,801)	($141,931)	($195,479)	($236,551)	($268,795)	($294,822)	($316,497)	($355,891)
Income after taxes	$125,868	$252,322	$347,518	$420,534	$477,858	$524,128	$562,661	$632,696
Net cash flow	$733,011	$685,995	$657,285	$641,796	$635,902	$637,016	$643,296	$632,696
Cumulative net cash flow	$733,011	$1,419,006	$2,076,291	$2,718,087	$3,353,989	$3,991,006	$4,634,302	$5,266,997

Net Present Value	**$1,291,081**
Internal Rate of Return	**27.1%**

Methane Emission Reductions (mcf/yr)	
Noncommercial gob gas	0
Ventilation gas	187,440
Total	**187,440**

Table 14 - Economic Analysis, 3.4 MW Gas-fired, Mine-mouth Power Turbine

Case # 5, recuperated engine at low TRIT with primary fuel of 80% methane

Assumptions:			
Cost of unit	$2,125,000	Inflation factor	3%
Maintenance cost ($/kwh)	$0.0035	Unit availability (hrs/yr)	8,000
Fuel gas price ($/mcf)	$1.75	Elec. power value or cost ($/kwh)	$0.048
Gob gas LOE	$0.31	Power output (MW)	2.537
Royalty (as % of mkt val)	12.5%	Fuel useage (mcf/hr)	42.6
Severance tax (as % of mkt val)	5.0%	Percent of energy value from fumigant	62.0%
Depreciation	7 year, DDB	Fuel quality of primary fuel (% methane)	80.0%

Results: (year of operation)	1	2	3	4	5	6	7	8
Annual power output (kwh)	20,296,000	$20,296,000	$20,296,000	$20,296,000	$20,296,000	$20,296,000	$20,296,000	$20,296,000
Revenue	$974,208	$1,003,434	$1,033,537	$1,064,543	$1,096,480	$1,129,374	$1,163,255	$1,198,153
Fuel cost	($50,183)	($51,688)	($53,239)	($54,836)	($56,481)	($58,176)	($59,921)	($61,719)
Royalty & severance tax (gob gas)	($32,635)	($33,614)	($34,622)	($35,661)	($36,731)	($37,833)	($38,968)	($40,137)
Royalty & severance tax (fumigant)	($53,247)	($54,844)	($56,489)	($58,184)	($59,930)	($61,727)	($63,579)	($65,487)
Maintenance cost	($71,036)	($73,167)	($75,362)	($77,623)	($79,952)	($82,350)	($84,821)	($87,365)
Total cost	($207,100)	($213,313)	($219,713)	($226,304)	($233,093)	($240,086)	($247,289)	($254,707)
Net revenue	$767,108	$790,121	$813,824	$838,239	$863,386	$889,288	$915,967	$943,446
Depreciation	($607,143)	($433,673)	($309,767)	($221,262)	($158,044)	($112,889)	($80,635)	$0
Taxable income	$159,965	$356,447	$504,058	$616,977	$705,342	$776,399	$835,332	$943,446
Income tax (Fed & State)	($57,587)	($128,321)	($181,461)	($222,112)	($253,923)	($279,504)	($300,719)	($339,640)
Income after taxes	$102,377	$228,126	$322,597	$394,865	$451,419	$496,895	$534,612	$603,805
Net cash flow	$709,520	$661,800	$632,364	$616,127	$609,463	$609,784	$615,247	$603,805
Cumulative net cash flow	$709,520	$1,371,320	$2,003,684	$2,619,811	$3,229,274	$3,839,059	$4,454,306	$5,058,111

Net Present Value	**$1,166,293**
Internal Rate of Return	**25.6%**

Methane Emission Reductions (mcf/yr)	
Noncommercial gob gas	129,504
Ventilation gas	211,296
Total	**340,800**

Table 15 - Economic Analysis, 3.4 MW Gas-fired, Mine-mouth Power Turbine

Case # 5 with no royalty or severance tax on fumigant

Assumptions:			
Cost of unit	$2,125,000	Inflation factor	3%
Maintenance cost ($/kwh)	$0.0035	Unit availability (hrs/yr)	8,000
Fuel gas price ($/mcf)	$1.75	Elec. power value or cost ($/kwh)	$0.048
Gob gas LOE	$0.31	Power output (MW)	2.537
Royalty (as % of mkt val)	12.5%	Fuel useage (mcf/hr)	42.6
Severance tax (as % of mkt val)	5.0%	Percent of energy value from fumigant	62.0%
Depreciation	7 year, DDB	Fuel quality of primary fuel (% methane)	80.0%

Results: (year of operation)	1	2	3	4	5	6	7	8
Annual power output (kwh)	20,296,000	$20,296,000	$20,296,000	$20,296,000	$20,296,000	$20,296,000	$20,296,000	$20,296,000
Revenue	$974,208	$1,003,434	$1,033,537	$1,064,543	$1,096,480	$1,129,374	$1,163,255	$1,198,153
Fuel cost	($50,183)	($51,688)	($53,239)	($54,836)	($56,481)	($58,176)	($59,921)	($61,719)
Royalty & severance tax (gob gas)	($32,635)	($33,614)	($34,622)	($35,661)	($36,731)	($37,833)	($38,968)	($40,137)
Royalty & severance tax (fumigant)	$0	$0	$0	$0	$0	$0	$0	$0
Maintenance cost	($71,036)	($73,167)	($75,362)	($77,623)	($79,952)	($82,350)	($84,821)	($87,365)
Total cost	($153,854)	($158,469)	($163,224)	($168,120)	($173,164)	($178,359)	($183,709)	($189,221)
Net revenue	$820,354	$844,965	$870,314	$896,423	$923,316	$951,015	$979,546	$1,008,932
Depreciation	($607,143)	($433,673)	($309,767)	($221,262)	($158,044)	($112,889)	($80,635)	$0
Taxable income	$213,211	$411,291	$560,547	$675,161	$765,272	$838,127	$898,911	$1,008,932
Income tax (Fed & State)	($76,756)	($148,065)	($201,797)	($243,058)	($275,498)	($301,726)	($323,608)	($363,216)
Income after taxes	$136,455	$263,226	$358,750	$432,103	$489,774	$536,401	$575,303	$645,717
Net cash flow	$743,598	$696,900	$668,517	$653,365	$647,818	$649,290	$655,938	$645,717
Cumulative net cash flow	$743,598	$1,440,498	$2,109,015	$2,762,380	$3,410,198	$4,059,488	$4,715,426	$5,361,142

Net Present Value	**$1,347,323**
Internal Rate of Return	**27.7%**

Methane Emission Reductions (mcf/yr)	
Noncommercial gob gas	129,504
Ventilation gas	211,296
Total	**340,800**

Table16 - Economic Analysis, 3.4 MW Gas-fired, Mine-mouth Power Turbine

Case # 6, Base Case with a $0.25/Mcf emission reduction credit

Assumptions:			
Cost of unit	$1,700,000	Emission reduction credit ($/Mcf)	$0.25
Maintenance cost ($/kwh)	$0.0035	Inflation factor	3%
Fuel gas price ($/mcf)	$1.75	Unit availability (hrs/yr)	8,000
Gob gas LOE	$0.31	Elec. power value or cost ($/kwh)	$0.042
Royalty (as % of mkt val)	12.5%	Power output (MW)	3.451
Severance tax (as % of mkt val)	5.0%	Fuel useage (mcf/hr)	42.6
Depreciation	7 year, DDB	Percent of energy value from fumigant	11.2%
		Fuel quality of primary fuel (% methane)	80.0%

Results: (year of operation)	1	2	3	4	5	6	7	8
Annual power output (kwh)	27,608,000	$27,608,000	$27,608,000	$27,608,000	$27,608,000	$27,608,000	$27,608,000	$27,608,000
Revenue	$1,159,536	$1,194,322	$1,230,152	$1,267,056	$1,305,068	$1,344,220	$1,384,547	$1,426,083
Fuel cost	($117,269)	($120,787)	($124,411)	($128,143)	($131,988)	($135,947)	($140,026)	($144,226)
Royalty & severance tax (gob gas)	($76,263)	($78,551)	($80,907)	($83,334)	($85,835)	($88,410)	($91,062)	($93,794)
Royalty & severance tax (fumigant)	($9,619)	($9,907)	($10,205)	($10,511)	($10,826)	($11,151)	($11,485)	($11,830)
Maintenance cost	($96,628)	($99,527)	($102,513)	($105,588)	($108,756)	($112,018)	($115,379)	($118,840)
Total cost	($299,779)	($308,772)	($318,035)	($327,576)	($337,404)	($347,526)	($357,952)	($368,690)
Net revenue	$859,757	$885,550	$912,116	$939,480	$967,664	$996,694	$1,026,595	$1,057,393
Depreciation	($485,714)	($346,939)	($247,813)	($177,010)	($126,435)	($90,311)	($64,508)	$0
Taxable income	$374,043	$538,611	$664,303	$762,470	$841,229	$906,383	$962,087	$1,057,393
Income tax (Fed & State)	($134,655)	($193,900)	($239,149)	($274,489)	($302,842)	($326,298)	($346,351)	($380,661)
Credit for emission reduction	$85,200	$87,756	$90,389	$93,100	$95,893	$98,770	$101,733	$104,785
Income after taxes	$324,587	$432,467	$515,543	$581,081	$634,280	$678,855	$717,469	$781,517
Net cash flow	$810,302	$779,406	$763,356	$758,091	$760,715	$769,166	$781,977	$781,517
Cumulative net cash flow	$810,302	$1,589,708	$2,353,064	$3,111,154	$3,871,870	$4,641,036	$5,423,013	$6,204,529

Net Present Value	**$2,222,238**
Internal Rate of Return	**43.5%**

Methane Emission Reductions (mcf/yr)	
Noncommercial gob gas	302,630
Ventilation gas	38,170
Total	**340,800**

recuperated unit analyzed in Tables 12 through 15 is an estimate. Solar Turbines has manufactured recuperated turbines in the past but does not now make a recuperated unit equivalent to the Centaur 40. However, the technology for such units is well established. It is estimated that the cost of such a unit will be 20% to 25% greater than the Centaur 40. In the analyses, the higher estimate of 25% is used as the unit cost.

Maintenance Cost. The costs stated in "Assumptions" are based upon years of operation of the Centaur 40 and similar units. It is possible that coal fines entrained in either the ventilation air or gob gas may require filtration before either gas is fed to the turbine. The cost of this operation is not known to any degree of certainty but it is not anticipated that the cost of filtering will have a substantial effect on maintenance costs.

Fuel Gas Price. None of the economic analyses assume that fuel will be purchased. However, it is assumed that royalties and severance taxes may be owed for either or both of the gob gas and vented methane utilized as fuel. A reference price for computation of these charges must therefore be used. The price of $1.75 is chosen as representative of present trends in the spot market of natural gas in the Black Warrior Basin.

Lease Operating Expenses. Lease operating expenses for gob gas are based generally upon the experience of Black Warrior Methane Corp. In the analyses, LOE assumes a system of wells, pipelines, and compressors designed to handle gas down to 45% methane with no dehydration other than mechanical. It covers all costs incurred in producing, treating, transporting, and compressing the gas. It is assumed that gas will be gathered in low pressure lines and boosted to the turbine's operating pressure by on-site compression. LOE does not include the cost to drill and complete wells. It is assumed that the project has an existing ventilation program which utilizes vertical wells drilled from the surface.

Royalty Rate & Severance Tax. Royalty and severance taxes are based upon the "market value" of natural gas at the wellhead. The rates chosen for each are assumed to be reasonable averages of the rates which would be encountered in areas for which projects as discussed in this proposal would be appropriate. "Market Value" is the gross revenue from gas sales less all post-production operating expenses. In the examples, LOE is the only expense charged against royalty and severance tax. The inclusion and method of calculation of royalty and severance tax charges against revenue is not an opinion that the applicability of royalties and severance taxes are determined by the same criteria, or that royalties and severance taxes might be owed for any or all of the cases examined in the economic analyses, or that the method of computation is the only method by which royalties and severance taxes might be fairly and legally calculated.

The authors recognize that the issue of whether royalty or severance tax are due requires the application of different standards. Royalties are payable by contract, generally a document identified as a "mineral lease." While such contracts can be as varied as the skill of the draftsmen and the limits of the law allow, a typical provision might read:

> As royalty, lessee covenants and agrees . . . to pay lessor on gas and casinghead gas produced from said land (1) when sold by lessee, one-eighth of the net proceeds derived from such sale, or (2) when used by lessee <u>off said land</u> or in the manufacture of gasoline or other products, the market value, at the mouth of the well, of one-eighth of such gas and casinghead gas, lessor's interest, in either case, to bear one-eighth of the cost of compressing, dehydrating, and otherwise treating such gas or casinghead gas to render it marketable or usable and one-eighth of the cost of gathering and transporting such gas and casinghead gas from the mouth of the well to the point of sale or use (emphasis added).

On the other hand, the payment of severance tax is established by law, and is generally payable for any severed mineral sold or used in any beneficial fashion, whether on or off the premises. The possibility that either might be due for gob methane sold or used beneficially by the miner and a sense of fiscal conservatism suggest that both be included in the cost items of the analyses. The inclusion of all costs incurred from the wellhead to the point of sale appears fair and supportable. The exclusion of depreciation on, or a rate of return for, the gathering system or pipeline is not intended as a comment on whether such items can be charged against either royalty or severance tax. All costs is based upon present trends in the spot market price of natural gas and is held flat for the life of the analysis.

Whether royalty or severance tax should be paid for the fuel value of the ventilation air is a closer question than in the case of gob gas. To the knowledge of the authors, there has never been any commercial utilization of ventilation air. Without attempting to address in any detail all the legal arguments pro and con, the economic analyses have been run with alternate cases in which no payment for royalties or severance taxes is charged for the fraction of fuel value derived from ventilation air. In the low TRIT cases, Cases 2, 4, and 5, the exclusion of royalty and severance tax in this fashion has a significant effect on overall economics.

Depreciation. For the unit described in this report, various depreciation methods are in common use. For the analyses, accelerated depreciation was used with a seven year life and 20% salvage value.

Emission Reduction Credit. This line item appears only in Case #6. In none of the other cases is any monetary value placed upon the reduction in emissions. The use of the item in Case #6 is to demonstrate the possible effect on the profitability of the turbine if laws are enacted to tax emissions or reward emission reductions. A tax credit was used as the accounting vehicle for ease of calculation and based upon the precedent of the Nonconventional Energy Tax Credit under § 29 of the Internal Revenue code.

Inflation Factor. It was deemed prudent to make some accounting for the effects of inflation. In the cases, revenue, fuel cost, and maintenance cost were made subject to the inflation factor. Because a high inflation factor tends to overstate revenue, and because not all of the variables will be equally affected by inflation, a rather modest factor of 3% was assumed.

Unit Availability. It is assumed that the unit will operate full time and not as peaking plants. The factor of 8,000 hours per year stated in "Assumptions" assumes that the unit will be operational 90% of the time.

Electric Power Value or Cost. It is assumed that any mine generating enough methane to supply fuel for the turbine described will also have electric power demands that can readily utilize all of the output of the turbine. The amount chosen as power cost is the estimated cost of power purchased by the mine that will be displaced by electricity generated by the turbine. In Cases 1 and 3, a power cost of 4.2¢/kwh was chosen based on the experience of JWR. In Case 2, a cost of 4.5¢/kwh was needed to make the economics favorable. In Cases 4 and 5, the power cost was raised to 4.8¢/kwh. Cases 2, 4, and 5 are examples of operating the turbine at a low turbine rotor inlet temperature (TRIT) of 1450^o in order to make the most effective use of the methane in the ventilation air. In these examples, the turbine derives from 30.4% to 62% of its fuel from the ventilation air. In Cases 1 and 3, the turbine is operated at the maximum TRIT of 1660^o. The utilization of methane in the ventilation air is only 10% to 11.2%. The trade off for the greater amount of essentially free fuel when operating at the lower TRIT is a substantial reduction in power output. A comparison of the cases indicates that, under the assumptions used, the greater amount of essentially free fuel from the ventilation air does not offset the decrease in power output.

Fuel Usage. The factor of 42.6 mcf/hr is based upon historical data and includes both gob gas and ventilation air.

Percent of Energy from Fumigant. This is the percentage of thermal energy derived from the methane entrained in the ventilation air or "fumigant."

Fuel Quality of Primary Fuel. The primary fuel is that fuel injected into the combustion chamber to distinguish it from the methane in the fumigant which enters the turbine through the compressor inlet. In the cases, the fuel value is varied from 80% methane to 100% methane. When the primary fuel is 80% methane, there is a slight increase in power output over a case where 100% is used. However, the analyses indicate that the increase in operating cost incurred in moving dilute fuel generally compensates for the increase in output. The significance of the cases analyzing 80% fuel is to indicate that less than pipeline quality gob gas can be very profitable used as fuel for a turbine. At mines where the production of pipeline quality methane is not feasible, that gas may nevertheless be very suitable as fuel for a combustion turbine. Appropriate monitoring and control technology can be effective in keeping fuel quality within the relatively narrow range required by the turbine. In most cases, this will be ±10% of the design value.

Annual power output is the product of unit availability and power output.

Revenue is the product of annual power output and electric power value or cost, adjusted for inflation.

Fuel cost is the cost to gather, treat, compress, and transport to the turbine gob gas used as fuel and is the product of unit availability, fuel usage, and gob gas LOE, adjusted for inflation. Fuel cost is also adjusted for the quality of the primary fuel. The gob gas LOE of 31¢/mcf is based upon 100% methane. For gob gas that is 80% methane, LOE will be 125% of 31¢/mcf.

Royalty and severance tax (gob gas) is charged against the net of revenue less fuel cost for that fraction (100% less percent of energy value from fumigant) of the energy value supplied by gob gas.

Royalty and severance tax (fumigant) is charged against the net of revenue less fuel cost for that fraction of the energy value supplied by the methane entrained in the ventilation air.

Maintenance cost is the product of unit availability and maintenance cost per kwh, adjusted for inflation.

Total cost is the total of fuel cost, all royalties and severance taxes, and maintenance cost.

Net revenue is the net of revenue less total cost.

Depreciation is by the double declining balance method over a seven year life with no salvage value.

Taxable income is the net of net cash flow less depreciation.

Income Tax is computed at the marginal rate of 34% for Federal and 2% for State income taxes. No other taxes, such as ad valorem or local income taxes, are included in the analyses.

Credit for emission reduction is a line item only in Case #6. It is the product of the total methane emission reductions stated at the foot of Table 16 and the emission reduction credit stated in "Assumptions." It is taken as a dollar-for-dollar reduction of tax without any attempt to account for such variables as alternative minimum tax.

Income after taxes is the net of taxable income less income tax.

Net cash flow and *cumulative net cash flow* are the annual and cumulative total of income plus depreciation.

Net present value was computed using a discount factor of 10% on the revenue stream of a negative capital cost and positive net cash flows.

Methane emission reductions include gob gas only if the quality is 80% (Cases 1, 2, and 5) and that fraction of the methane supplied from ventilation air. The total amount is the product of unit availability and fuel usage. No credit is given for gob gas which is 100% methane on the premise that such gas is of pipeline quality and can therefore be sold. This premise is adopted for the sake of simplicity although it begs the question of whether 100% gob gas can in all situations be transported and marketed profitably.

4.6.2 Base Case & Case #3

The Base Case (Tables 6 and 7) and Case #3 (Tables 10 and 11) are identical except for the quality of the primary fuel. In both cases, the turbine is operated at maximum TRIT and the value of electric power is placed at 4.2¢/kwh. In the base case, the primary fuel is gob gas that is 80% methane. In Case #3, the primary fuel is 100% methane. The additional power output gained by using dilute fuel does not offset the increase in fuel cost. Omitting the payment of royalty and severance tax for the fumigant has little effect on economics. Both of these cases look very attractive under the assumptions used.

4.6.3 Case #2

Case #2 (Tables 8 and 9) is similar to the base case but with the TRIT reduced from 1660° to 1450° and the power cost increased from 4.2¢/kwh to 4.5¢/kwh. Reducing the TRIT increases the percentage of fumigant used as fuel from 11.2% to 30.4%. The price for this free fuel is a reduction in power output from 3.451 MW to 2.5 MW. This case indicates that the economics are most sensitive to power output and power cost under the assumptions used in the analysis.

4.6.4 Cases #4 & 5

These cases (Tables 12-15) show the effect of substantially increasing the percentage of fumigant used as fuel by employing the more fuel efficient design of a recuperated turbine engine. The increase in fuel efficiency, however, does not overcome the increase in capital cost expected for a recuperated engine over the Centaur 40, and a power cost of 4.8¢/kwh is required to make the economics appear favorable.

4.6.5 Case #6

This case (Table 16) is intended to show the impact of a tax incentive in the overall economic picture. A credit against income of 25¢/mcf is allowed. Whether congress or any of the states will ever enact legislation which provides a tax incentive to reduce emissions is an unknown. Under the factors assumed for Case #6, the effect of a tax credit is substantial.

4.7 Market Potential

For power generation as outlined in this proposal, the potential market in the United States appears to be very large. Outside the U.S., it appears to be immense although far more difficult to evaluate. USEPA recently completed a study of the potential for economic utilization of mine methane in the U.S. (EPA-430-R-94-012, 1994). If 1 million cf of methane is chosen as the minimum level of daily mine emissions which can support a project as outlined in this proposal, the USEPA study shows 57 mines in the U.S. which meet that criteria. These 57 mines emit a total of 418 million cf of methane per day. Many of these mines may not be candidates for a turbine project for many reasons: ownership questions may be discouraging, there may be no gob gas production (many of the 57 mines are room-and-pillar; others have no reported gob production) or no reasonable access to pipelines, the mine may lack or be reluctant to advance the capital needed for the project, the remaining life of the mine may be too short to justify the capital costs or local utilities may deter alternate energy production. However, if only half of the mines reported are prospective candidates for a ventilation stream turbine, their total emissions are 209 mmcfd of methane. The turbine unit described in this proposal consumes approximately 296 mcfd/MW of capacity. Larger units tend to be more efficient. Solar Turbines' 10.1 MW unit consumes 256 mcfd/MW. Using this fuel consumption range to gauge the market, there may be the potential to generate 706 to 816 MW of power from mine gas in the U.S. by the methods outlined in this proposal.

Evaluating the market outside the U.S. is more problematic. There are, to the best of our knowledge, no analogous studies of power generation potential for mines outside the U.S. The information that is available indicates that it is not unreasonable to assume that the overseas market is greater than the U.S. market by an order of magnitude or more. It has been estimated that approximately 1,825 Bcf/yr (5,000 mmcfd) of methane is emitted in the nine countries (excluding the U.S.) with the most coal mine emissions (EPA/400/9-90/008, 1990). Many of the countries identified as significant sources of mine methane emissions also have substantial needs for more electric power generating capacity (Moore, 1995). In examining the overseas market, it is not unreasonable to assume that many of the same problems, including ownership or right to utilize methane, that are presented in the U.S. will be encountered. In addition, other market problems may be found. Uncertainties, inequities or inconsistencies in the laws, regulations and commercial practices in many emerging economies, particularly those of China and the former Soviet Union, may be the determining factor regardless of the technical or economic merits of a project. Delays due to governmental inefficiency or lack of infrastructure may profoundly influence the cost and profitability of a project. However, if only 10% of the estimated worldwide mine methane emissions can be used for turbine power generation, the market for this method is 1,689 to 1,953 MW of capacity.

4.8 Future Systems

The economics of using the methane in the mine ventilation air for power production drive toward introducing all of the methane required as fuel through the compressor with the air flow. Typically this would require a 1.4 to 2% concentration of methane in the air stream. To allow the safe fumigation of this level of methane in air a specially designed gas turbine system would be required. Generally the gas turbine system would be designed to operate at the lowest possible methane in air concentration.

If the mine-ventilation-air market for gas turbines proves to be large it is possible that such a purpose designed system might be developed. Two basic engine approaches could be used to operate with (desirably) low methane concentrations in the compressor air. One would simply use very low firing temperatures to lower the methane levels needed and to eliminate cooling flows. The second approach would reduce the methane concentrations required by improving the system efficiency through recuperation in some form. A combination of low firing temperatures and recuperation could also be used. The simplest of the combined systems would be a low efficiency, low turbine inlet temperature, recuperated engine. A sophisticated high efficiency approach would probably employ an intercooled recuperative (ICR) cycle for the gas turbine. The intercooled compressor would minimize the likely autoignition problems inherent with high pressure ratio machines while enhancing efficiency and power density.

To be practical any approach that uses fuel delivered with the air stream will probably need a catalytic combustion system. Such an approach minimizes the potential problems of flashback and local autoignition by providing very low combustion temperatures. In addition to the catalytic combustor a purpose designed gas turbine would probably employ externally plumbed combustor bypass air passages. Providing the required engine pressurization and cooling air flows in external ducts or pipes will allow easy access for extra cooling or flow substitution. Reducing the temperature of the air that is to be used for turbine blade and vane cooling is an effective approach to minimizing or even eliminating autoignition. This technique also provides an enhanced cooling capability. Externally supplied air or possibly steam could also be added to, or substituted for, the cooling air stream, again to minimize autoignition problems and to improve blade cooling effectiveness.

A version of an ICR engine system employing hydraulic instead of mechanical air compression is also possible. Many coal mines have disused shafts and galleries that could be easily adapted or converted to hydraulic air or gas compressors. Hydraulic air compression systems (using water falling down a deep shaft) could provide cool, oxygen depleted air, at pressure, to a modified gas turbine. Such a gas turbine would have no rotating compressor, since the hydraulic compressor would fulfill this function. The cool air would be fed directly to the combustor. After combustion of fuel the gases would be expanded through the first and second (if present) stage turbines. These former gas producer turbines would be arranged to drive an electrical generator. This type of power generation has a significantly higher power density than any other related system. In addition the oxygen depleted air has the potential to provide much lower NO_X emissions than could be attained with normal ambient air. Hydraulic compressor/gas turbine hybrids have the potential of achieving over 50% thermal efficiency, with extremely low No_X emissions, and exceptional power density.

5.0 Phase II Activities

The proposed Phase II effort will cover the design of a complete gas turbine system capable of operating with coal mine ventilation air. This system will use higher quality methane or methane air mixtures as the primary fuel. The proposed project design will be based on the system described above, which in turn, is constructed from existing equipment available from Solar Turbines and other commercial suppliers. Detailed mechanical equipment design arrangements and specifications will be prepared for the proposed system. A detailed cost analysis of the proposed system will also be produced. These costs will include estimates of both the first cost and life cycle costs. Repair and maintenance costs over the estimated life of the system will be reported separately.

6.0 Conclusion

The site selected for the potential demonstration project is at the Jim Walter Resources Blue Creek No. 5 Mine (JWR No. 5), located in north-central Alabama within eastern Tuscaloosa County. The South fan shaft at JWR No. 5 is driven with a single fan that produces an average flow of about 620,000 scfm, with an average gas content of 0.51%. The North shaft has two fans, that together deliver about 1,425,000 scfm with an average gas content of 0.52%. Together these shafts release about 15 mmcf/d of methane to the atmosphere. This rate is expected to continue more-or-less unabated until the projected end of mining in 2010.

A small portion of this flow can be used to supply combustion air to a turbine. A standard 3.4 MW turbine-generator package is now considered be the best candidate for a demonstration project, since its use will minimize minimize costs and design time. The 3.4 MW size is about right to run a single mine fan, and such a unit is portable. This unit can be trucked to the site, and placed on a pad, then later moved if the fan is moved. The additional hook-up that will be required includes ducting, an inlet air scrubber, fuel supply, and electrical connection to the existing fan motor.

The economic assessment, based on installation of a Solar Turbines Centaur Model 40 at the Jim Walter Resources No. 5 Mine, shows that the proposed project appears economically attractive, even without considering the emissions benefits. This unit would produce enough power to drive a single fan, provide a profitable rate of return, and produce a 2% reduction in emissions from a single fan.

Finally, the initial market study indicates that with the methods outlined in this report, there is the potential to generate 706 to 816 MW of power from mine gas in the U.S. Worldwide, if only 10% of the estimated mine methane emissions can be used for turbine power generation, this technology still has potential for generation of 1,689 to 1,953 MW of capacity, with a commensurate reduction in emissions.

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