Mitigation of Methane Emissions from Coal Mine Ventilation Air

Peter Carothers[1] and Milind D. Deo[2]
[1]Alternative Energy Development, Inc., Silver Spring, MD, U.S.A.;
[2]Dept. of Chemical and Fuels Engineering, University of Utah, Salt Lake City, UT, U.S.A.

ABSTRACT

U.S. EPA's coalbed methane outreach program, (CMOP) has prepared a technical assessment of techniques that combust trace amounts of coal mine methane contained in ventilation air. Control of methane emissions from mine ventilation systems has been an elusive goal because of the magnitude of a typical airflow and the very low methane concentrations. One established and cost-effective use feeds the air into a prime mover in lieu of ambient combustion air. This method usually consumes just a fraction of the flow available from each ventilation shaft. The authors evaluated the technical and economic feasibility of two emerging systems that may accept up to 100% of the flow from a nearby shaft, oxidize the contained methane, and produce marketable energy. Both systems use regenerative, flow-reversal reactors. One system operates at 1000°c, and the other uses a catalyst to reduce the combustion temperature by several hundred degrees. Above certain minimum methane concentrations the reactors can exchange high quality heat with a working fluid such as compressed air or pressurized water. This paper discusses two illustrative energy projects where the reactors produce energy revenue and greenhouse gas credits and yield an attractive return on invested capital.

KEYWORDS

Coal, Methane, Mining, Ventilation, Combustion, Regenerative, and Greenhouse Gas.

INTRODUCTION

This paper presents a summary of a draft U.S. Environmental Protection Agency (U.S. EPA) report. It is a technical assessment of existing and emerging processes capable of removing trace amounts of methane contained in ventilation air streams at gassy underground coal mines.

Coalbed methane (CBM) is methane that is formed during the coalification process and that resides within the coal seam and adjacent rock strata. Coal mining activity releases methane that has not been captured with drainage systems. The methane then passes into mine workings and on to the atmosphere. Gassy underground mines release significant quantities of such methane, which is referred to as coal mine methane (CMM). When allowed to accumulate in mine workings, CMM presents a substantial danger of fire and explosion. To assure miner safety and maintain continuous production, operators of gassy mines must degasify their mines.

The most universally used method of degasification is dilution by ventilation. Ventilation systems consist of inlet and exhaust shafts and powerful fans that move large volumes of air through the mine workings to maintain a safe working environment. Exhausted ventilation air contains a very diluted amount of methane; typical concentrations range between 0.2 to 0.8% methane, well below the explosion limits. To date (with very few exceptions) ventilation systems release the air-methane mixture to the atmosphere, thus emitting or liberating the methane without attempting to capture and use it. Operators may supplement ventilation with another form of degasification, methane drainage technology, which forcibly extracts methane from coal strata in advance of, or after, mining.

Some operators to employ a variety of proven methods, capture and use drained CMM but the majority of drained CMM is also released to the atmosphere along with the ventilation air. Methane emissions from ventilation air comprise the largest portion of all CMM liberation worldwide, and they are the most difficult to control. This paper examines the current and future possibilities for destroying and potentially using ventilation air methane.

Global Importance of Ventilation Air Emissions

Methane is a potent greenhouse gas, approximately 21 times more effective per unit of weight than carbon dioxide in terms of causing global warming over a 100-year time frame. Coal mine methane emissions account for approximately 10% of anthropogenic methane emissions worldwide, and they are the fourth largest source of methane release in the US. By far the largest portion of this methane leaves the mines through the ventilation system. Therefore, the most logical and direct way to reduce CMM emissions would be to find methods to capture, process, and use methane that exits the ventilation shaft. This paper assesses technologies that can be expected to handle the entire ventilation stream from a single shaft. A typical shaft at a gassy mine in the U.S. will move between 100 to 250 cubic meters of air per second (m^3/s) or approximately 212,000 to 530,000 cubic feet per minute (cfm). Illu-strations in this paper assume a unit capacity of 100 m^3/s, a practical modular size that mines could use singly or in multiples. A 100 m^3/s ventilation flow containing 0.5% methane will emit 43,200 m^3 of methane per day or about 1.525 mmcfd.

Barriers to Current Recovery and Use

Ventilation airflows are very large, and the contained methane is so diluted that conventional combustion processes cannot oxidize it without supplemental fuel. Ventilation air's characteristics make it extremely difficult to handle and process and constitute technical barriers to its recovery and use.

Costly Air Handling Systems. Typical ventilation airflows are so enormous that a processing system will have to be very large and expensive. Each processing system will have to include a fan to neutralize any pressure drop caused by the reactor and avoid having the mines face costly increases in electric power.

Low Methane Concentrations. A methane-in-air mixture is explosive in a concentration range between about 4.5 and 15%. Below 4.5% methane will not ignite or sustain combustion unless it can remain in an environment where temperatures exceed 1,000°C (1,832°F). Therefore, any conventional method proposed to use ventilation air as a fuel, or even to destroy it, would require an endothermic reaction.

Variable Flows and Changing Locations. Mine operators will face the flow variations typically exhibited by a ventilation system. As mine operations progress underground the working face tends to move away from the original ventilation shaft. A processing system built to accept a given flow will experience short-term periodic fluctuations and a probable decline over time as other, more distant exhaust shafts take over.

IDENTIFICATION OF APPLICABLE TECHNOLOGIES

The technologies available to mitigate ventilation air emissions divide into two basic categories: ancillary uses and principal uses.

Ancillary Uses

The focus of projects in this category is on a primary fuel that is not ventilation air; thus employment of ventilation air is ancillary and restricted to amounts that are convenient for the project. For example, a power plant or other prime mover may use ventilation air (instead of ambient air) as combustion air. Projects of this type normally use only a fraction of the ventilation air. The technique requires a modest air handling and transport system that serves to bring ventilation air from the shaft exit to the prime mover's air intake. The Appin and Tower projects owned by BHP Steel Collieries Division in Australia[1] provide an outstanding example of ancillary use. Two facilities totaling 40 and 54 MW each produce electric power with a series of one-megawatt Caterpillar internal combustion engine generators. Gob gas drained from the two mines is the primary fuel, but it is supplemented with methane (averaging about 0.7%) contained in the mine ventilation air that is used as each unit's combustion air in place of ambient air. This strategy increases the quantity of fuel available to the project by about 10% and consumes up to 20% of ventilation emissions. Since the project must rely on natural gas to supplement its primary fuel during periods of low CMM availability, the methane from ventilation air represents a significant cost savings. While BHP has not identified separate capital and operating expenditures for the air substitution part of the project, a Caterpillar spokesman stated that these were modest. They consisted of ducting installed from just above the ventilation fan to each engine's air intake, the air filtration system, and some additional programming at the control centers. There are no additional fans in the ductwork because the engines generate enough suction power to move ventilation air to their intake systems. One can conclude from the foregoing that the ventilation air substitution system is a simple, practical, and profitable technique for CMM use that could be replicated at many gassy mine settings where electric generation using gob gas may be viable.

[1] The Appin and Tower Collieries Methane Energy Project, a BHP Engineering Pty. Ltd. report provided by Geoff Bray, Project Engineer, September 26, 1998.

Combustion turbines, or gas turbines, may also use ventilation air as combustion air. Since it contains useable fuel, the operator can cut back on the quantity of primary fuel. Solar Turbines, a division of Caterpillar Inc., has investigated this strategy for use with small (e.g., 3 to 8 MW) turbines located near mine ventilation shafts. Although the company has no field experience with the technique, Solar engineers encourage its use in field applications, albeit within very strict methane concentration limits that they impose to guarantee the safe operation of the equipment.

Principal Uses

Technologies in this category would use ventilation air as the primary fuel and attempt to consume up to 100% of the methane emitting from a single exhaust shaft. As discussed below, these systems may also employ more concentrated fuels such as gob gas to enhance the utility or profitability of a given project. The authors identified two processes: a thermal oxidation process called the VOCSIDIZER, and a catalytic oxidation process called the Catalytic Flow-Reversal Reactor (CFRR). A description of each system follows:

VOCSIDIZER. This regenerative thermal oxidation process is being offered by MEGTEC Systems, a De Pere, WI-based subsidiary of Sequa Corp. The VOCSIDIZER was developed by ADTEC of Sweden, which now is a part of MEGTEC. The process is essentially a thermal flow-reversal reactor (TFRR) which operates above the combustion temperature of methane (i.e., above 1000°C (1832°F)). A large (55 m^3/s) VOCSIDIZER unit for VOC oxidation operates at the Volvo plant in Gothenburg, Sweden to oxidize paint fumes. This unit supplements the paint solvents with natural gas during periods when solvent concentrations fall below the limit required for self-sustained operation. Many other of MEGTEC's 600 plus installations also are capable of injecting methane in the form of natural gas to assure stability. A 3 m^3/s demon-stration VOCSIDIZER unit operated at a British Coal mine site for a period of six months. The MEGTEC has learned that the unit effectively destroyed methane in a partial flow withdrawn from the mine ventilation exhaust, although detailed information from those trials is not available.

CFRR. In 1995 researchers at ERDL/Natural Resources Canada in Varennes, Quebec (also known as CANMET and NRCan) conceived of and developed the Catalytic Flow-Reversal Reactor expressly for use on coal mine ventilation air. The research team was aware of and wished to improve upon the TFRR to process mine ventilation air at lower temperatures. CANMET selected catalysts that reduce the combustion temperature of methane by several hundred degrees Celsius. They have demonstrated the CFRR technology over a range of simulated conditions at small scale. CANMET and several Canadian private and government entities have formed a consortium to finance, design, build, and operate an industrial-scale demonstration plant (approximately 8 to 10 m^3/s) at the Phalen Mine in Nova Scotia. CANMET is also studying energy recovery options that are appropriate for the CFRR, especially the gas turbine option.

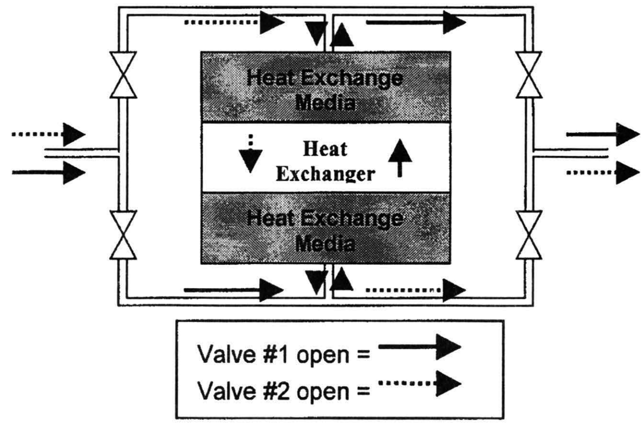

Figure 1. Schematic of flow-reversal reactor.

Principles of Operation

Figure 1 shows a schematic of a reverse-flow reactor. This is a simple apparatus that consists of a large bed of silica gravel or ceramic heat exchange medium with a set of electric heating elements in the center. Airflow equipment such as plenums, ducts, valves, and insulation elements are fitted around and within the bed. Controls and ancillary equipment are mounted nearby. The TFRR and CFRR have the same general appearance except the CFRR has zones on either side of the heat exchanger that contain catalyst pellets (not shown). The process employs the principle of regenerative heat exchange between a gas (ventilation air) and a solid (bed of heat exchange media selected to efficiently store and transfer heat) in the reaction zone. To start the operation, electric heating elements preheat the middle of the bed to the temperature required to initiate combustion (i.e., 1000°C-1100°C in the case of the TFRR). During the first half of the first cycle, ventilation air at ambient temperature enters and flows through the reactor in one direction. Methane oxidation takes place near the center of the bed when the mixture begins to exceed 1000°C. Thus, if these temperatures can be maintained in the bed, practically 100% conversion of methane (to carbon dioxide and water) can be achieved. All three sections of the reactor are well-insulated so that very little heat is lost to the surroundings.

If the gas is not heated to the combustion temperature of methane, the reaction will not start because there is no heat source. This situation is called a *non-starter*. Even if the reaction does start, the final conversion must be complete enough to heat the media, and in turn, the gas in the next cycle to the auto-combustion temperature. Otherwise, the reactor will cool down over a number of cycles. This situation is called a *blow-out.*

After the initial cycles of a sustained operation, hot products of combustion and unreacted air continue through the bed, losing heat to the far side of the bed in the process. When the far side of the bed is sufficiently hot and the near side has cooled, the reactor automatically reverses the direction of ventilation airflow. New ventilation air enters the far side of the bed and becomes hotter by taking heat from the bed. Close to the reactor's center the methane reaches combustion temperature, oxidizes, and produces heat to be transferred to the near side of the bed before exiting.

In an ideal situation the temperature profile in the bed would be as shown in Figure 2. When the ventilation air flows from bottom to top it picks up heat from contact with the hot solid media and its temperature increases. The gas temperature lags the solid temperature by a few degrees (about 20 to 50°C in existing units) both while gaining and losing heat according to MEGTEC. As the flow continues in the initial half cycle, the high temperature zone, with respect to both the solid and the gas, tends to migrate upward (for the bottom-to-top illustrative flow configuration). The flow reversal arrests this upward migration and prevents it from traveling too far from the center. The next half cycle flow (top-to-bottom) produces a new temperature profile, also shown in Figure 2. By switching flow direction at pre-calculated time periods, typically between two and ten minutes, the hot zone can be maintained in the center of the reactor.

As is observed in Figure 2, even with very efficient heat transfer the exit air temperature is at least a few degrees higher than the incoming ventilation air. As a result, if no energy is being generated internally, the bed would eventually cool. Both vendors claim that if the methane concentration in the incoming air is consistently about 0.15% and if the unit has been optimized to meet that parameter, the operation would be autothermic (i.e. it would support itself without additional applied heat or fuel). This would mean that oxidizing this quantity of methane will produce enough heat to compensate for an approximate 40°C temperature rise in the exit gas flow relative to incoming gas temperature. The goal of the technical assessments and numerical modeling is to verify vendor claims.

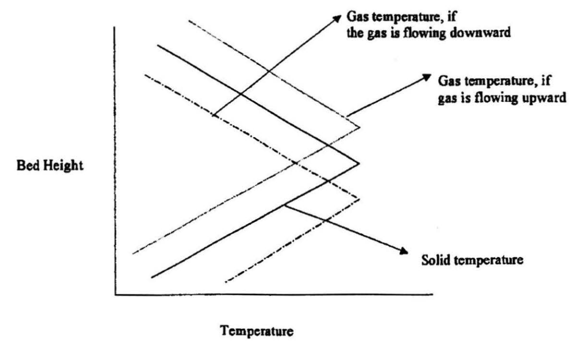

Figure 2. Ideal temperature profiles in flow-reversal reactor - CFRR or the VOCSIDIZER.

Heat Recovery. If the reactor has sufficient methane to reach thermal equilibrium, its exhaust gas temperature will be raised by a value equal to the adiabatic temperature increase in the reactor. The temperature reached depends only on the inlet methane concentration. There are three different methods of excess heat removal available. The most practical is to insert heat transfer coils (containing air, water, or other medium) into the hot zones of the reactor and recover a high-quality heat (e.g., 700°C to 800°C). Recovering heat from exhaust gases will yield a low quality heat (e.g., the adiabatic temperature increase for 0.5% methane would be about 133°C). The third method, directly using part of the gas at its highest temperature for heat transfer, is the most complicated of the three.

TECHNICAL EVALUATIONS

The University of Utah's Chemical Engineering and Fuels Department (U of U) prepared a technical assessment of the VOCSIDIZER and CFRR chemical reactor processes using computer simulation techniques. The analysts first described the physical phenomena occurring in the reactors. By working with the vendors and making reasonable assumptions based on similar processes found in the literature, the analysts at U of U were able to select a reasonable range of physical parameters to employ in the model. These parameters include reactor configuration, types of materials, voidage (a measure of bed porosity), pressure drops, velocities, and temperature profiles. The analysts expressed the physical system with differential equations and solved them using appropriate boundary conditions. They then used the models to test process feasibility and display operating characteristics.

The U of U concluded that both the VOCSIDIZER and the CFRR, operating on a steady supply of ventilation air at concentrations typically encountered in the field, are technically feasible processes for oxidizing methane. The CFRR remains stable and autothermic at low methane concentrations, and it blows out only when concentrations fall to just above 0.1%. Uncertainty arises with the VOCSIDIZER when methane concentrations fall to about 0.35%, the level at which blow-outs occurred during simulation trials. MEGTEC, however, affirms that the process continues to be autothermal even below 0.1% methane, based on experimental evidence. The researchers at U of U concede that under certain reactor configurations and with different design parameters it may be possible to lower the methane concentration bound at which the TFRR operates autothermally.

The CFRR assessment did not take into account the potential for conditions that could adversely affect catalyst performance (e.g., temperature cycling or catalyst poisoning from sources such as dust). These concerns can be studied during field trials. If such problems were to occur they would add to operation costs by requiring more frequent catalyst replacement and unscheduled down time.

In addition to the numerical modeling, the U of U performed an analysis of pressure drops created by the volume of ventilation air passing through the systems. The analysts calculated pressure drops for a range of flow rates, reactor diameters, and voidage and found them to be moderate. That finding indicates that vendors should be able to install reactors of a reasonable size and still maintain required air velocities using affordable fan systems. For example, with a porosity of 0.5, a flow rate of 10 m^3/s and a diameter of 6 m, the pressure drop is less than 400 mm of water.

While numerical modeling demonstrates that both flow-reversal oxidation processes are technically feasible, it is too soon to render definitive opinions on comparative performance because neither the CFRR nor the TFRR has operated on mine ventilation air at commercial scale. There are a few factors, however, that may tend to affect the selection of one process or the other. Because catalytic oxidation requires smaller units and lower temperatures, a CFRR project may have a lower capital cost. The CFRR was able to operate at lower concentrations during the model runs, although MEGTEC asserts that the VOCSIDIZER can match that performance. This factor is very important in estimating how much energy can be recovered from the reactor. On the other hand, VOCSIDIZER, with over 600 units operating in the field, would seem to have an advantage in terms of "proof of concept" as compared with CFRR's laboratory trials and modeling. Some of these units operate for finite periods on methane. Moreover, unlike the VOCSIDIZER, the CFRR must bear the added elements of purchasing, maintaining, and replacing a catalyst.

PRACTICAL METHODS TO USE ENERGY RECOVERED FROM VENTILATION AIR OXIDIZERS

While the emphasis of this paper is on the ability of various technologies to combust methane in ventilation air, it is important to explore the practical systems that will recover and use the energy thus created.

Heat Available for Recovery

When methane borne by the ventilation air combusts it releases heat, but not all of that heat is available for recovery. Some of the heat is required to sustain reactor temperatures, and if methane concentrations are in the lowest sustainable range, most or all of the heat of combustion goes for that purpose. The higher the concentrations are the greater will be the percent of heat that may be recovered by the heat exchanger. The relationship is exponential, so a small increase in concentration may result in a dramatic increase in the amount of energy available for recovery and use. Injection of supplemental methane such as gob gas just upstream of the poppet valves which admit ventilation air into the unit not only creates more heat, but it causes a larger fraction of that heat to be recovered. MEGTEC has used natural gas as support fuel in general industrial process air streams and is confident that they can achieve the same result with supplemental methane injection into the ventilation air. The use of gob gas to enhance heat recovery from the reactor may have to compete with using gob gas as a supplemental fuel in the prime mover, depending upon which use is more cost-effective.

Heat Exchanger Design

The embedded high temperature heat exchanger offers a high quality heat in the most practical form. Embedded heat exchangers, however, introduce a number of design questions that must be solved for each project application. Both the catalytic reactor and especially the TFRR reach temperatures that exceed the working limits of all but the more durable materials such as high-grade stainless steel, Inconel, and ceramics. In many cases, the price to be paid for materials that withstand high temperatures can be a good investment that will be repaid with increased revenues from gas turbines that produce electricity more efficiently with a higher temperature working fluid. If the circulating medium is pressurized water, less special design precautions are needed. The designer may have the flexibility to locate the heat exchanger piping (i.e., tubes, coils, etc.) at the point of highest temperature or at cooler points along the temperature gradient to trade-off high efficiency and performance with the high cost of exotic metallurgy. Placement of the heat exchanger may have an effect on the operation of the reactor, however, but research performed for this paper did not analyze any possible consequences. For ease of maintenance the reactor design should facilitate easy removal and replacement of the more vulnerable components.

Energy Conversion Options

The heat exchanger can deliver energy in the form of pressurized hot water or compressed hot air, so the developer has several options to produce useable energy.

Steam or Hot Water Generation. The simplest and least costly option is to raise steam or hot water for use in a district heating loop or industrial process, if such exist nearby. For example, heated and pressurized air exiting the heat exchanger can flow directly into a heat recovery boiler to produce either steam or hot water. If the working fluid is pressurized hot water it would flow to a flash tank where it converts to steam.

Electric Generation Using Steam Cycle. One method of generating electric power would be to flash pressurized hot water from the reactor's heat exchanger, create steam, and use it to power a steam turbine. The U.S.EPA report concluded that the steam cycle will require higher capital costs and produce lower cycle efficiencies when compared with a gas turbine case discussed below. Thus, it will be very difficult for a steam power generation cycle to be the priority energy use option for most applications.

Electric Generation Using Gas Turbine. The likely preferred energy recovery method will be electric power production in a gas turbine, possibly operating in a co-generation mode by recovering waste heat. This option operates as follows: Ambient air enters the compressor mounted on the air turbine's shaft and is compressed to between 7 to 22 atmospheres (or about 100 to 325 psig) depending upon the turbine design. Compressed air flows through the secondary loop of the gas-to-gas heat exchanger in the reactor where it receives excess heat of combustion. It then returns to the turbine's expansion section where part of its energy converts to mechanical energy and then into electrical energy in the generator. Spent hot air then enters a waste heat boiler, which captures useful thermal energy, if co-generation is desired.

A gas turbine's efficiency improves as a function of the temperature of its working fluid, but most high-efficiency gas turbine specifications call for higher rotor inlet temperatures than are economically available from a ventilation air oxidizer. The highest practical temperature range for the reactor outlet may be between 750°C and 800°C (1382° F and 1472° F), and that is at or below the input needs of older and smaller gas turbines. The system designer will carefully match the temperature and mass flow characteristics available at a given mine with one of the many and diverse off-the-shelf gas turbines available.

The design effort will be aided greatly if the mine can supply sufficient gob gas or another affordable fuel for supplementary combustion in the turbine to raise the working fluid temperature to or near design levels. In some cases, the supplementary firing needs will compete with the need to supplement vent air methane concentrations. If ample supplemental fuel were available it could be possible to adjust the mass flow and firing temperatures to correspond exactly to a given gas turbine's design specifications, allowing it to operate at optimum efficiency. If gob gas is insufficient to allow the gas turbine to achieve its design temperatures, the project may either decide to purchase natural gas or oil for that purpose, or to operate at a derated output and a reduced efficiency.

Where there is little or no demand for co-generated steam there may be cost-effective methods to improve electric production by using heat exhausted from the gas turbine. One suggestion might be to insert an interstage heating unit at the turbine exhaust to use waste heat to raise the temperature of pressurized air going to the reactor's heat exchanger. This would decrease the working fluid's temperature gain in the heat exchanger and allow for an increased flow, a larger turbine, and extra revenue. Such considerations should wait, however, until the basic process has proven itself in field trials.

COST ANALYSES OF HYPOTHETICAL PRINCIPAL USE PROJECT CONFIGURATIONS

The two vendors of reverse-flow reactors, MEGTEC and CANMET, supplied EPA with some very preliminary cost estimating information on a system rated at 100 m^3/s of mine ventilation air. It is important to understand that cost data supplied for a general report such as this will be very approximate and subject to change for the following reasons:

- Neither vendor has built and operated a full-scale unit appropriate for use at a gassy coal mine.
- The economics of energy recovery and marketing from reverse-flow oxidizers are not well known because the need to mitigate local pollution, rather than to compete in the competitive field of energy supply, has driven the justification of all systems installed to date.
- System costs will vary greatly from one application to another due to the variation in physical and economic parameters at each site.
- Each vendor applied a different and unknown standard of conservatism to the estimates.
- Neither vendor is willing to reveal sensitive and confidential cost estimating information.

Nevertheless, the authors have gathered enough cost information to build reasonable models that can suggest the economic viability of either the VOCSIDIZER or the CFRR operating in the domestic U.S. marketplace. A review of the limited cost data received showed that there is no clear difference between the two systems' costs, and any attempt to compare one against the other would be based on an incomplete understanding of the underlying case-specific design variables and would be misleading. Therefore, the following illustrative cases are based on a "generic" design that blends the two systems and obscures any differences in performance, capital costs, and operating and maintenance costs.

Project A. Principal Use of Ventilation Air in a Flow-Reversal Oxidizer with a Gas Turbine Cogeneration Plant

This hypothetical project uses a single flow-reversal unit rated at 100 m^3/s to capture most or all of the emissions from a nearby ventilation shaft at a gassy mine in the U.S. Project A relies on the methane captured from the ventilation shaft as its primary source of energy, and it relies on a limited supply of gob gas to enhance heat recovery in the oxidizer. In the "fired case" gob gas also finds a use in the gas turbine to raise the working fluid temperature and make better use of the turbine's high-temperature capability. The fired case assumes that a substantial amount of methane in the form of gob gas is available to the project developer – a situation that may exist in several gassy mines in the U.S. The "unfired case" assumes a lower gob gas flow to work with, and directs all of it into the reactor to enhance heat recovery. A waste heat boiler placed at the gas turbine exit recovers thermal energy in the form of slightly superheated steam for both cases.

Cost estimates are based on information supplied by both vendors plus conservative estimates supplied by the contractor. The reactor costs in the neighborhood of $3 million plus soft costs. Turbine-generator costs at $650/kWh assume a reconditioned older unit. Revenue estimates include power sales at a low of 3.0 cents and a high of 4.5 cents/kWh. Revenues also included an assumption for greenhouse gas credits for methane destroyed at $1.50 per Mt of CO_2 times methane's global warming effect of 21.

Using a power price of $0.045 and a carbon dioxide credit of $1.50 per Mt, base case versions of the unfired and fired configurations showed a 27 and 40% internal rate of return (IRR) respectively. The project is reasonably resistant to at least one negative parameter change. For example, if the capital cost were to rise by 20% or the electric price were to fall by one cent, the fired case would still be financially attractive and the unfired case would be close to an attractive range. Also the project is resilient to a 20% shortfall in either methane concentration or gob gas supply.

Project B. Principal Use of Ventilation Air in a Flow-Reversal Oxidizer in a Waste Heat Boiler Plant

Hypothetical Project B uses a single flow-reversal unit rated at 100 m^3/s to produce steam in a waste heat boiler. This option is useful when the mine is located near a stable thermal market such as a district heating system or a brine evaporation plant. Project B has a much simpler configuration than Project A, and its capital cost is substantially lower. The developer has two options if a substantial amount of gob gas were readily available: injecting it into the heat exchanger to increase the methane concentration, or firing it in the boiler to increase steam production. Gob gas added to the heat exchanger will yield an exponential increase in energy versus a linear increase in the boiler. Therefore, the developer would have a tendency to direct all supplemental methane into the reactor to enhance both the heat quantity and heat recovery percentage. Some of the reactor cost estimates used in Project A are applicable for Project B. The thermal energy sales price is $3.00/mmBtu, or about 1.0 cent/kWh. The same $1.50 per Mt for CO_2 was assumed.

Project B also has an excellent potential for profitability at a site where conditions are favorable. If the market for thermal energy could support a price of $0.01 per kWh and the project could earn carbon dioxide credits of $1.50 per Mt, the project might show an IRR of about 33%. Even if the capital cost were to rise by 20% the project's IRR would come close to 25%. The IRR would remain above 25% if gob gas suffered a 25% shortfall or if ventilation air methane dropped to 4.4%. The project could only accept about a 14% drop in the thermal price before falling below 25% IRR, but that drop could be restored with a US$0.70 increase in the price of a metric ton of carbon dioxide.

CONCLUSIONS

The recovery and use of CMM coincides with its purity, and paradoxically, takes place in the reverse order of its occurrence in the field. In other words, relatively small amounts of pipeline quality CMM are almost totally consumed; the more prevalent gob gas is occasionally used; and the most dominant form of CMM (i.e., that contained in ventilation air) is used only in rare instances around the world. Thus, the search for viable methods that use or at least destroy a major percentage of this important source of greenhouse gas becomes extremely important to those who wish to effectively mitigate methane emissions from coal mines.

Ancillary Uses

This paper has made a distinction between technologies that use ventilation air as an ancillary fuel and as a primary fuel. Ancillary uses depend upon a nearby power facility or similar energy consumer which uses another fuel as its primary fuel. Ancillary uses normally offer only a partial destruction of ventilation air emissions. The leading ancillary use example is the Appin Colliery in Australia which consumes up to 20% of the methane emitted from its ventilation shaft in 54 internal combustion engines. One can expect to see more examples of partial or secondary ventilation air uses in new settings where physical and economic conditions are conducive to establishing a facility based on the primary fuel, and where the use of ventilation air is ancillary.

Technical Feasibility of the Principal Use of Ventilation Air

Two ventilation air processors identified in the report are in somewhat different stages of development. MEGTEC's VOCSIDIZER is in use at over 600 locations throughout the world, but only one facility operated exclusively on ventilation air, and the results of that demonstration are not yet available. Several of their other units operate intermittently on dilute natural gas when concentrations of target compounds (i.e., industrial volatile organic compounds) are insufficient to maintain the reaction. CANMET's CFRR, developed expressly for mine ventilation air, is operating at bench scale and will go into an industrial scale demonstration in late 1999. Analysts at the University of Utah performed a technical assessment of these two reactors using numerical modeling, and they were able to draw significant conclusions:

- Both technologies are technically able to oxidize dilute methane in ventilation air.
- Both technologies will produce useable energy from a heat exchanger operating at a useful temperature range.
- CFRR and VOCSIDIZER modeling results favored the CFRR, primarily because it can sustain operation at a lower concentration. MEGTEC challenges this observation by citing experimental and field experience.
- If these computer simulations have correctly recognized this difference in autothermal concentration limits, the CFRR will recover a somewhat higher percentage of useable energy from the reactor.

These independent observations, coupled with the fact that flow-reversal reactors have operated successfully, give confidence that regenerative flow-reversal technology, with or without a catalyst, will achieve success during commercial-scale field trials using actual mine ventilation air.

Economic Viability of Flow-reversal Reactors

This paper presented two preliminary economic analyses of project scenarios using a flow-reversal reactor coupled to: 1) a gas turbine co-generation facility, and 2) a waste heat boiler. Both hypothetical projects appeared to be profitable when operating in appropriate energy markets while taking advantage of modest credits for the greenhouse gas emissions that the projects would mitigate. The economic models showed the projects to be resilient to changes in major revenue assumptions. Because these economic stud-ies were based on a series of assumptions and not actual field data, it is too early to rely on them with total confidence. They are a source of hope, however, that solutions for elimination of methane emissions from ventilation air shafts may be affordable in the near future.

Impact of Carbon Credits

It is useful to consider the implications of the assumed value of carbon credits with respect to the economic modeling conducted for this analysis. In the fired cogeneration base case, including the value of carbon credits in the economic analysis results in a very substantial internal rate of return of 40.2%. Removing those credits, however, still leaves the project with an IRR of 29.2%, which should be more than adequate to attract investors. Therefore, because this scenario does not require carbon credits to achieve economic viability, it is likely that it would be expected to move forward on its own merits absent such credits, and thus would not be eligible to garner credits in any case.

In both the thermal case and the unfired co-generation base cases, project IRRs are 33.3% and 26.9%, respectively, when carbon credits are included in the economic analysis. Removing those credits, however, reduces the IRRs to an economically unattractive range, 14.3% and 16.5%, respectively. Therefore, they would meet the criterion that would be additionally necessary to assure their eligibility for such credits, and it is logical to assume that carbon credits would accrue to both of these projects, thereby supporting their economic viability.

Curiously, both of the above observations are good news for those interested in pursuing ventilation air use projects. With IRRs in the neighborhood of 25%, fired co-generation generation applications should be economically attractive to investors on their own regardless of how the emerging carbon credit market evolves. When that market does mature, the carbon credits accruing to both the thermal and unfired co-generation cases should make those applications viable as well. Thus, regardless of the direction in which a carbon credit market develops, technologically and economically feasible options for productively using ventilation air appear to be available.