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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

# Hebi No. 6 Coal Mine, Hebi Coal Field, Henan Province, China: *Feasibility Study for Coal Mine Methane Drainage and Utilization*

U.S. Environmental Protection Agency

2010

**Hebi No.6 Coal Mine, Hebi Coal Field**

**Henan Province, China:**

# *Feasibility Study for*

# *Coal Mine Methane Drainage and Utilization*

**Sponsored by:**

**US Environmental Protection Agency, Washington, DC USA**

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**2010**

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# Acronyms and Abbreviations

## Unit Abbreviations

| | |
|---|---|
| ‰ | parts per thousand |
| % | parts per hundred |
| °C | degrees Celsius |
| °F | degrees Fahrenheit |
| $ | United States Dollar |
| Bcf | billion ($10^9$) standard cubic feet |
| Bcfd | billion ($10^9$) standard cubic feet per day |
| $Bm^3$ | billion ($10^9$) cubic meters |
| Btu | British thermal unit |
| D (d) | day |
| daf | dry, ash-free basis |
| ft | feet |
| in | inch |
| km | kilometer |
| $km^2$ | square kilometer |
| m | meter |
| $m^3$ | cubic meter |
| $m^3$/min | cubic meters per minute |
| $m^3$/t | cubic meters per tonne of coal |
| Mcf | thousand ($10^3$) standard cubic feet |
| Mcfd | thousand ($10^3$) standard cubic feet per day |
| Mcm | thousand ($10^3$) cubic meters |
| Mcmd | thousand ($10^3$) cubic meters per day |
| mD | millidarcy ($10^{-3}$ D) |
| mm | millimeter ($10^{-3}$ m) |
| MMcf | million ($10^6$) standard cubic feet |
| MMcfd | million ($10^6$) standard cubic feet per day |
| MMcmd | million ($10^6$) cubic meters per day |
| MPa | Megapascal |
| Mtoe | million tonnes of oil equivalent |
| MW | Megawatt |
| psi | pounds per square inch |
| scf | standard cubic feet |
| Tcf | trillion cubic feet |

## Acronyms and Other Abbreviations

| | |
|---|---|
| ARI | Advanced Resources International, Inc. |
| CBM | Coalbed Methane |
| CDM | Clean Development Mechanism |
| $CH_4$ | Methane |
| CMM | Coal Mine Methane |
| CNG | Compressed Natural Gas |
| $CO_2$ | Carbon Dioxide |
| $CO_2$eq | $CO_2$ Equivalent |
| Fm | Formation |
| HCIG | Hebi Coal Industrial Group |
| HDPE | High Density Polyethylene |
| IC | Internal Combustion |
| ID | Inner Diameter |
| IPCC | Intergovernmental Panel on Climate Change |
| IRR | Internal Rate of Return |
| JWR | Jim Walters Resources |
| LNG | Liquified Natural Gas |
| LPG | Liquified Petroleum Gas |
| MLD | Multi-lateral Drilling |
| $MTCO_2$e | Million tonnes $CO_2$ equivalent |
| $N_2$ | Nitrogen |
| NDRC | National Development and Reform Commission |
| NPV | Net Present Value |
| RMB | Renminbi |
| SDIC | State Development Investment Corporation |
| Shengli | Shengli Power Company Ltd. |
| U.S. | United States |
| US$ | United States Dollars |
| USBM | United States Bureau of Mines |
| USDOE | United States Department of Energy |
| USEPA | United States Environmental Protection Agency |
| VAM | Ventilation Air Methane |
| VAT | Value-Added Tax |

**Acknowledgments**

The USEPA and the ARI Team gratefully acknowledges the support of Hebi Coal Industrial Group for providing valued access to information, personnel, and the Hebi Mine No.6 site during the course of this study.

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# Executive Summary

## Introduction

This feasibility study was sponsored by the United States Environmental Protection Agency (USEPA) in support of the U.S. - China Strategic Economic Dialogue. The study was also a flagship project for the Coal Mining Task Force of the Asia-Pacific Partnership on Clean Development and Climate, of which EPA was a lead participant. The Coal Mining Task Force seeks to improve mine safety and increase Coal Mine Methane (CMM) production and use in Partner countries. It does this by promoting the use of more effective methane drainage technologies and techniques in advance of mining, and the recovery of low concentration CMM in ventilation air.

This study identified a suitable mine in China where the potential benefits of improved methane drainage could be assessed and quantified. The study was divided into several tasks:

- 1. Pre-feasibility study and mine site selection
- 2. Geologic overview and resource assessment
- 3. Market assessment of produced methane
- 4. Evaluation of degasification technologies and reservoir simulation
- 5. Evaluation of methane utilization technologies
- 6. Emission reductions from project implementation
- 7. Capital and operating costs; economic and financial analyses
- 8.Potential impacts and recommendations

## Pre-Feasibility Study and Mine Site Selection

ARI evaluated and screened several potential Chinese coal mines to determine their suitability for the development of a large scale CMM project. Hebi Mine No.6, located in the Hebi mining area of northern Henan province, was eventually selected for having the largest number of favorable project parameters.

The mine is one of eight in the region operated by Hebi Coal Industry (Group) Corporation. It produces 1.2 million tons of coal a year and has a projected production life of 80 years, giving ample time for a long term CMM capture and use project. In-situ coals have a high gas content and are extracted using longwall technology, which produces significant gob gas emissions. Pre- and post-mining methane drainage systems are already installed at the mine, but there is potential to upgrade and expand these systems. Methane with an average concentration of 20% is drained from the mine and is used to power five Shengli reciprocating engines which generate approximately 50% of the mine's electricity needs. The potential to increase drained gas quality and quantity to power new generator sets, which produce electricity with an immediate market at the mine, was a significant factor in the selection of Hebi Mine No.6 as a study site.

**Geologic Overview and Resource Assessment**

The active extensional tectonics of the North China Basin, in which the Hebi mine area is located, result in complex local geology and challenging mining conditions at Hebi Mine No.6. ARI researched and reviewed the regional and local geology using available data, including regional seismic data and stratigraphic, fault mapping and coal geology data provided by the mine.

The Hebi coal leases are situated within a series of small, fault-bounded coal basins which make up the Taidong coal region in north-central China. Primary coal bearing units are the Early Permian Shanxi and Late Carboniferous Taiyuan Formations, which occur in a 200+ meter thick sequence of alternating coal seams, shales and shaly sandstones. The mine area is heavily faulted with faults having throws between 100-500 meters and striking generally NE-SW. These large faults control the delineation of the coal mines in the region.

At Hebi Mine No.6, the development area is influenced by a series of smaller NE striking normal faults which complicate the mining process and contribute to high stress conditions and resultant coal gas outbursts. Seam $2_1$ is the principal mined coal in the Hebi area, with a total resource of nearly 4 billion tons. Parts of the shallower Seam 1 coal are also mineable. Seam $2_1$ is mined at depths of 300-400 meters at Hebi Mine No.6, averages 8 meters in thickness, and dips between 8-50 degrees with an average of 20 degrees. The mines in the area are considered very "gassy" and have some of the highest gas contents in China - ranging between 16 to 32 $m^3$ per tonne. The average gas content at Hebi Mine No. 6 is 22 $m^3$ per tonne and the total CMM resource of the active development area is estimated to be 21 billion cubic meters, with a further 60 billion $m^3$ in the deeper, undeveloped areas.

**Market Assessment for Produced Methane**

ARI reviewed the status of China's energy markets at a national, regional and local level to determine demand for the greater produced CMM volumes anticipated from implementing new gas drainage techniques at Hebi Mine No. 6.

Most major studies of China’s energy use predict steady increases in the use of all energy sources over the next twenty years. As the cheapest fuel, coal will still provide the bulk of energy requirements, but China’s national government is actively promoting the use of natural gas in an effort to reduce pollution from the country’s heavy coal use. They anticipate boosting the share of natural gas as part of the country’s total energy consumption, from the current 4% to 10% by 2020.

Hebi Mine No.6 is sited within a major industrial area with a large residential population. As such, there is a large demand for both electrical power and natural gas in the area and this demand is predicted to grow steadily at rates of 5-10% a year. Hebi City receives natural gas via a trunkline from the West-to-East pipeline and has a well developed gas distribution system. The city is supplied with electricity from a local thermal plant and major transmission lines from the regional grid. Hebi City is a transportation hub with good rail and road access to Beijing and the region's major cities.

Hebi Mine No.6 currently generates 50% of its electricity needs and purchases the remainder from the local grid. ARI believes the most attractive market for the CMM volumes produced by upgrading the mine’s methane drainage system and drilling techniques is electricity generation for the mine's use. The produced electricity will supply approximately 91% of Hebi Mine No. 6’s power needs, which leaves capacity in the system to utilize any increases in CMM production above and beyond those predicted in this study.

Generating electricity on site is attractive, because the input CMM gas stream can be used as is, with minimal processing and transportation. Additional generating sets can be installed relatively cheaply and infrastructure for the power plant and distribution system is already in place. The other major markets reviewed: sales to pipeline; sales to residential users; compressed natural gas (CNG) production and liquid natural gas (LNG) production; all require significant processing of the CMM gas stream to increase its methane concentration and remove contaminants. A specialized processing plant would have to be installed, with subsequent training of mine personnel on use and maintenance. CNG and LNG production would require construction of production facilities, while gas sales would require the building of pipelines to suitable sales points. The low volumes of CMM produced at the mine are not deemed sufficient to provide the economies of scale needed to make the aforementioned end uses of CMM more economically attractive than electricity generation.

**Evaluation of Degasification Technologies and Reservoir Simulation**

The different degasification techniques employed in the coal mining industry were reviewed, followed by a detailed examination of current degasification techniques at the Hebi No. 6 mine. Recommendations based on numerical simulations are provided that will help the mine increase its drainage efficiency, both in terms of quality and quantity of gas produced.

Current mine degasification practices were modeled using ARI's Comet 3 CBM reservoir simulator. A baseline case was generated and used to model and evaluate alternative degasification methods. Results were used to derive recommended practices. The overall impact of the recommended practices and the costs of implementation are presented.

Current pre-mining drainage practices at Hebi No. 6 mine include:

- face drainage, consisting of short fan boreholes drilled in advance of gate developments,
- gallery drainage, comprised of short fan boreholes drilled into future longwall panels from galleries driven below the mining seam, and
- cross-panel boreholes drilled from gate entries in advance of longwall mining.

Gob gas drainage practices implemented at Mine No. 6 include:

- horizontal gob boreholes drilled from galleries developed above the mining seam, and
- pipe laid in the gob to recover gas generated from remnant coal, or from sealed gob areas.

Reservoir modeling of cross-panel gas drainage indicated that directionally drilling the drainage boreholes would have multiple benefits over the current non-directional drilling method. The new technique will reduce residual gas contents to below those achieved with the current system over the same drainage period, particularly for the lower benches of the coal seam. This system would recover 24 percent more methane than current practices. The reduction in residual gas content of the lower benches reduces methane emissions into the gob by an average of 18.5 percent. Other benefits of this system relative to current practices include:

- 50 percent fewer boreholes drilled;
- 83 percent fewer drill setups, borehole collars, standpipes, and wellheads;
- fewer wellheads minimizes potential for air intrusion into gathering system, improves recovered gas quality;
- fewer boreholes reduces methane drainage costs;
- potential reduction in drainage time by reducing borehole spacing from 12 m to 11 m;
- fewer boreholes provides for reduced time required for drilling;
- a 15 percent increase in gas content reduction after 21 months;
- reduced residual gas contents improves mine safety;
- reduced residual gas contents enable increased coal production.

Directional drill units can also be used to drill drainage boreholes in advance of gate road development. The current system of drainage involves drilling a fan array of short boreholes into the gate road face and degassing for only 12 hours before mining. Directionally drilled boreholes should be drilled in conjunction with the cross-panel boreholes and maintained ahead of gate developments as far as possible. The benefits of this system over the current system are:

- reduced gas contents in advance of gate development;
- fewer drill setups to interrupt face advance;
- the structure of coal seam can be defined in advance of developments;
- outburst zones can be detected further in-by gate developments,
- improved mine safety,
- increased mining rates.

It is also recommended to directionally drill gob boreholes over the length of the longwall panel, instead of the current practice of drilling multiple boreholes from an overlying gallery. Benefits include:

- three wellheads per panel compared to up to 35;
- no overlying drilling galleries required saving on infrastructure development costs;
- minimizes potential for air intrusion into the gas collection system and provides for improved recovered gob gas quality, and;
- fewer collars provides for better vacuum control and monitoring.

Suggested improvements to the underground gas gathering system include use of High Density Polyethylene (HDPE) pipe instead of steel pipe, the installation of pipeline integrity safety systems and the installation of upgraded measuring and monitoring equipment.

If all these recommendations are implemented at the mine, it is estimated that the methane drainage rate would increase by 25% from 23,000 $m^3$/day to 28,750 $m^3$/day and the average recovered gas quality would increase from under 20% $CH_4$ to over 50% $CH_4$ (Exhibit 1).

| CMM Drainage Method | Averaged Recovered Gas Quality (% $CH_4$) | Methane Drainage Rate ($m^3$/day) STP |
|---|---|---|
| Current | 17-21 | 23,000 |
| Recommended | 50-70 | 28,750 |

**Exhibit 1: Projected increase in methane drainage volume and recovered gas quality for Hebi Mine No. 6.**

### Evaluation of Methane Utilization Technologies

The ability to utilize methane produced from degasification systems has grown with advances in gas processing and power generation technologies. In China, these advances now allow for CMM with methane concentrations as low as 20% to be commercially utilized, and methods for utilizing methane in concentrations of 1% or less (VAM) are currently in the early stages of commercialization. Advanced Resources evaluated the technical feasibility of several methane utilization technologies that may be applicable for use at Hebi Mine No.6 including: firing hot water boilers; direct use in residential areas; fueling reciprocating engines for electricity generation; processing to upgrade gas to pipeline quality; production of liquid natural gas (LNG); production of compressed natural gas (CNG); flaring; and ventilation air methane (VAM) capture to fuel electricity generation.

Electricity generation using CMM fueled reciprocating engines is widespread in China, although much of the generation uses CMM with concentrations below 30% - a practice prohibited in Western countries. Several large generation projects (up to 120 MW) use international generators fueled with mid-concentration CMM and this is technically feasible at Hebi Mine No.6 if the proposed drainage upgrades occur and raise the current CMM concentration.

ARI evaluated the processing techniques for increasing CMM methane content to a level where it could be either injected into sales pipelines or used to produce LNG and CNG. Several methods have had technical success, but must be used in large scale projects with large minimum CMM input flows to ensure commercial success. New technologies are being adapted for use with small projects, but are yet to be proven economically feasible.

Abatement of VAM using thermal flow reversal reactor technology was analyzed and found to be technically feasible at Hebi Mine No. 6. Options studied included methane abatement only; heat generation, and power generation.

Many factors determine which CMM utilization options are economic, but the most important are usually the methane concentration and produced volumes of drained CMM, and the distance of the mine to potential markets. Hebi Mine No. 6 benefits from being only 15 km from Hebi City, which has large industrial, commercial and residential sectors as potential energy customers. However, the projected produced CMM volumes and methane concentrations of the project are low relative to existing successful CMM utilization projects in China and provide a significant challenge to the economics of several utilization options.

**Emission Reductions from Project Implementation**

The Hebi Mine No.6 degasification project is intended to reduce methane emissions vented to the atmosphere during the mining process. This will be achieved by increased pre-mining methane drainage from the coal seams, more efficient capture of gob gas emissions, and destruction of ventilation air methane at the surface. Drained methane will be used for electricity generation.

The proposed project at Mine No. 6 contributes to China's sustainability by providing domestically-produced clean energy and by reducing emissions of greenhouse gases (GHG) that would otherwise be emitted to the atmosphere. Since methane ($CH_4$) is a greenhouse gas (GHG) with a global warming potential (GWP) over 20 times greater than carbon dioxide ($CO_2$), projects that capture and utilize or destroy methane have the capacity to generate a considerable amount of carbon offsets in the process. Using the framework provided through the clean development mechanism (i.e., approved consolidated methodology ACM0008), potential emission reductions from the proposed project activity were quantified.

The recommended project approach will upgrade the degasification system and utilize methane liberated from Mine No. 6 in two ways. Firstly, new gas engines with a total capacity of 2.5 MW will be added to the 5 existing gas engines in order to utilize 100% of the extracted CMM to produce electricity and heat. The power produced will be used for the mine's own consumption, replacing electricity that would otherwise be purchased from the Central China Power Grid (CCPG). Waste heat from the engines will be utilized to supply hot water to nearby mining facilities. Secondly, up to two units of a newly developed methane oxidation technology will be installed at the East Wing ventilation shaft to destroy ventilation air methane with low $CH_4$ concentrations (below 1%). This technology will also produce thermal energy that can be substituted for coal-based heat.

Total emission reductions over a ten-year crediting period are estimated at **2,378,800 $tCO_2e$**. Exhibit 2 summarizes baseline and annual emissions, as well as annual emission reductions, by project component.

| Project Component | Total Annual Baseline Emissions ($tCO_2e$/yr) | Total Annual Project Emissions ($tCO_2e$/yr) | Total Annual Emission Reductions ($tCO_2e$/yr) |
|---|---|---|---|
| CMM-to-power/heat | 134,345 | 21,750 | **112,592** |
| VAM-to-heat | 155,678 | 30,393 | **125,285** |
| Combined CMM-to-power/heat and VAM-to-heat | 290,023 | 52,143 | **237,880** |

**Exhibit 2: Annual Emissions and Emission Reductions by Project Component**

## Capital and Operating Costs; Economic and Financial Analysis

Hebi Mine No.6 currently drains an average of approximately 8.4 million $m^3$ of coal mine methane (100% $CH_4$) each year and uses 5.76 million $m^3$ of the gas to produce half of the mine's annual electricity needs. It is proposed in this feasibility study that upgrading the mine's methane drainage systems and techniques, would result in a 25% increase in methane drainage (to 10.5 million $m^3$ per year). ARI evaluated the operating costs and financial benefits of several electricity generating options that are available to fully utilize the proposed increased gas stream. The options evaluated were: installing Chinese made generator sets only; installing a mixture of Chinese and international generator sets; and installing international generator sets only.

The main capital costs for the methane drainage upgrading include the purchase of two sets of directional drilling equipment; the purchase of two sets of HDPE pipe fusion equipment; a pipeline integrity and monitoring system; and subsequent training of the mine staff on all new equipment. This is estimated to total $4,193,000. The recommended new methane drainage system of multi-layer directional in-seam drilling will result in approximately the same total length of drill hole (drilled per year) as under the current drilling system. The proposed new system of draining the gob will negate the current technique of mining overlying drilling galleries. Therefore, overall drilling costs associated with the new methane drainage system are expected to be less than, or equivalent, to current expenses. New electricity generating capacity will be purchased and initial cost, including installation, is calculated at $739 per kw.

Incremental economics is a way of comparing one project with another by subtracting their economic results and this analysis method is used in situations when a decision among mutually exclusive projects is necessary. For the Hebi Mine No. 6 economics, five individual economic analyses, described in Section 7.3 were performed. From the resultant cashflows, incremental economic analyses were carried out on the electricity generating scenarios mentioned above.

In each of the five individual cases, economic cashflow, costs and expenses were escalated at 3% per year, and each kWh of power generated results in a savings (revenue) of $0.0547/kWh in avoided power purchases from the grid. The most favorable of the three incremental cases considered was the installation of high efficiency generator sets, with a total capacity of 2.5 MW, at Hebi Mine No.6, which will utilize all of the proposed available CMM volume to generate electricity for mine use.

The economics of three potential scenarios of VAM utilization (abatement only, heat generation, and power generation) are detailed in Section 5.10. Abatement of VAM while generating heat is calculated to be the most economic scenario, with a capital expenditure of US$6.5 million paid back in 4.2 years and producing an IRR of 24% over 15 years.

**Potential Impacts and Recommendations**

The proposed coal mine methane drainage and utilization improvement project at Hebi Mine No.6 has considerable positive technical, economic, and environmental merit. The proposed new methane drainage techniques would improve the safety and technical efficiency of CMM drainage and transport at the mine. The resultant production of CMM with higher methane concentration would expand the range of safe CMM utilization options. By using CMM supplies that are currently being vented, the project would monetize an otherwise wasted energy source and reduce total GHG emissions associated with the mine.

If successful, the advanced techniques, equipment, and management practices demonstrated by the project could be applied broadly to the other coal mines in the Hebi Coal Field, resulting in significantly increased CMM utilization and reduced GHG emissions in this strategic coal mining region.

# SECTION 1

# Pre-Feasibility Study and Mine Site Selection

# SECTION 1 CONTENTS

# SECTION 1 EXHIBITS

## 1.1 Introduction

China is the world's largest coal producer, and as a result is also the world's largest source of coal mine methane (CMM) emissions. Every year, the high methane concentrations present in many of China's coal mines cause explosions responsible for the deaths of several thousand miners. At the same time, millions of cubic meters of CMM are vented to the atmosphere representing a long term threat to the environment as a green house gas (GHG) and the waste of a valuable energy resource.

The U.S. Environmental Protection Agency (USEPA), in its ongoing efforts to promote mine safety and increase CMM capture and use worldwide, has sponsored a feasibility study to assess improved CMM drainage and utilization, along with potential ventilation air methane (VAM) use, at a coal mine in China.

## 1.2 Mine Selection Process

The first step in this study was to evaluate and screen potential coal mines in China at which to conduct the feasibility study. A questionnaire was developed, translated into Chinese, and sent to three mines in order to determine their suitability for the development of a large-scale CMM project (Section 1.6.1). Two of the three sent back responses. Questions were developed to determine the size of the CMM resource base, the ability to extract the methane through degasification systems (e.g., in-mine horizontal wells, GOB wells, directional holes), the ability to utilize the methane at, or somewhere near, the mine site, and other geologic and engineering data required to construct a development plan.

The first group contacted was the Landcome Group, a Chinese company that controls several mines in Shanxi province. After reviewing the data provided by the mines, it was determined that they were probably too small to initiate a project of significant size that would be of interest to potential investors. This is not to say that these mines do not have any CMM development potential. It is likely that Landcome may try to develop some type of pre-mine drainage system on their properties in the future.

Contact was also established with the Guizhou Coal Initiative (GCI) to inquire about the willingness of mines in Guizhou to participate in the feasibility study. The GCI personnel were responsive and provided us with the name and contact details of one mine manager, but after repeated attempts to contact this individual, other mines were pursued.

In January of 2008, Advanced Resources was contacted by Sakel Coal, a consortium comprised of two US companies and the Hebi Coal Administration that was formed to develop the CMM resources of the Hebi coal mining area (Exhibit 1-1 and Exhibit 1-2). There are currently 8 mines that are in operation and one that is in the development stage. There are coal expansion plans for four mines listed in Exhibit 1-3.


**Exhibit 1-1: Location of Mining Area**

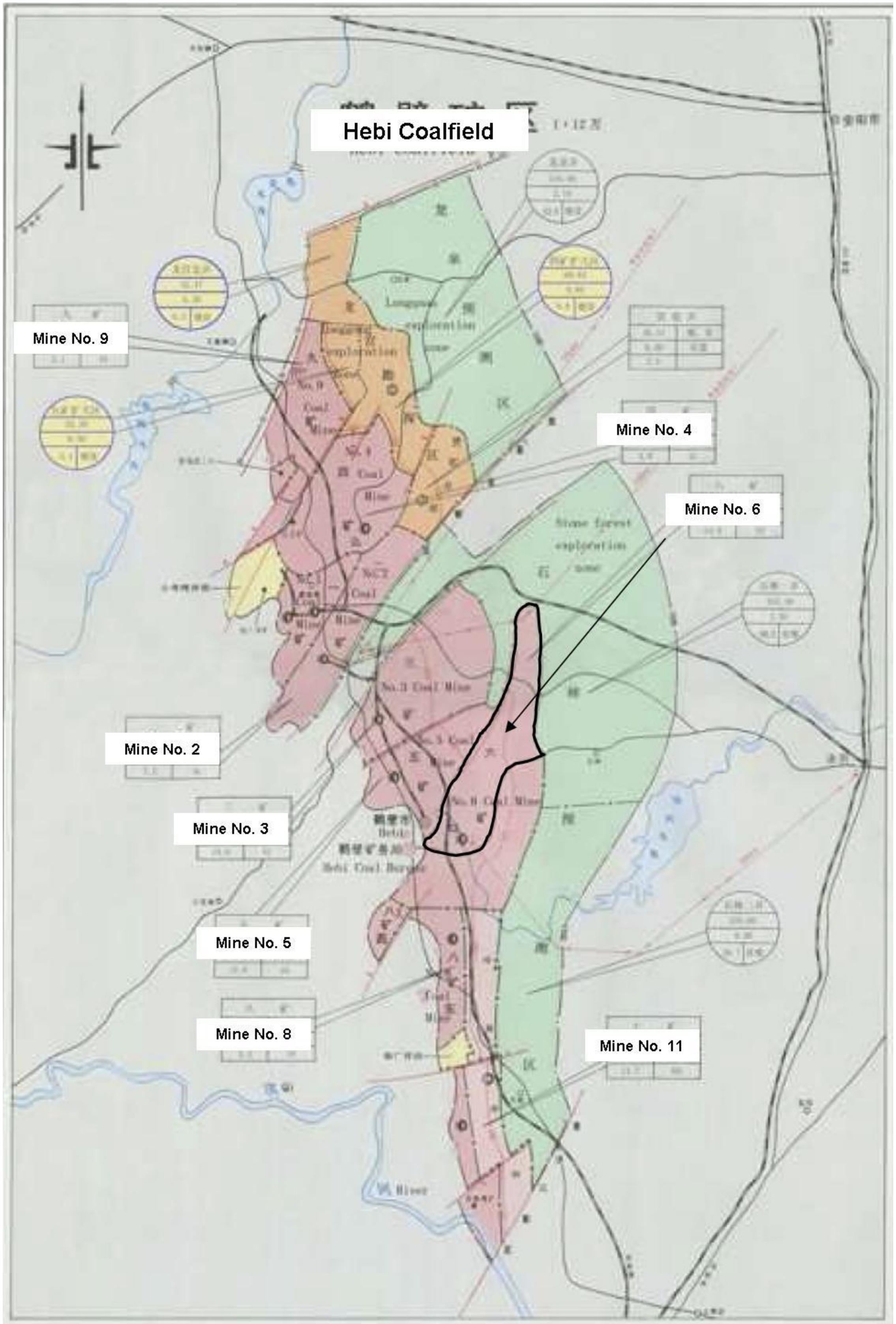


**Exhibit 1-2: The Eight Mines of the HEGC in the Hebi Coal Field**

**Using Hebi PDD Values**
350 KW
0.799 On line factor
10400 Btu/kWh

**1st Half 2006 data**

**Gas Drainage**

| Mine | Location | Concentration | Flow of CH4 m3/min | Flow of CH4 MMCFD | Total Gas MMCFD | Electricity, kWh Daily | Electricity, kWh Annual | MW Potential | July, 2007 Utilization 10,000 m3/mo | July, 2007 Utilization MMCFD | exist units | MMCFD/unit | Remaining CH4 Gas MMCFD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | -420 | 3% | 0.6 | 0.03 | 1.02 | 2,397 | 874,925 | | | | | | |
| | -170 | 11% | 2 | 0.10 | 0.93 | | | | | | | | |
| | -170 | 6% | 1.3 | 0.07 | 1.10 | | | | | | | | |
| 3 | Surface | 14% | 6 | 0.31 | 2.18 | 23,971 | 8,749,246 | 1.79 | 14.5 | 0.1655806 | 2 | 0.083 | 0.140 |
| | Underground (North) | 8% | 1.8 | 0.09 | 1.15 | | | | | | | | |
| | Underground (North) | 8% | 2.5 | 0.13 | 1.59 | | | | | | | | |
| | Underground (South) | 15% | 2.2 | 0.11 | 0.75 | | | | | | | | |
| | Horizon 3 | 3% | 1 | 0.05 | 1.70 | | | | | | | | |
| 4 | Surface | 35% | 15 | 0.76 | 2.18 | 59,926 | 21,873,115 | 4.46 | 12.5 | 0.1427419 | 4 | 0.036 | 0.622 |
| | -250 | 12% | 2.5 | 0.13 | 1.06 | | | | | | | | |
| | Horizon 3 | 11% | 8 | 0.41 | 3.71 | | | | | | | | |
| 5 | South Wing | 15% | 4 | 0.20 | 1.36 | | | | | | | | |
| | North Wing | 6% | 1.4 | 0.07 | 1.19 | | | | | | | | |
| 6 | Surface | 20% | 12 | 0.61 | 3.06 | 47,941 | 17,498,492 | 3.57 | 49 | 0.5595484 | 5 | 0.112 | 0.052 |
| | North Wing | 3% | 0.2 | 0.01 | 0.34 | | | | | | | | |
| | North 7 | 5% | 1.2 | 0.06 | 1.22 | | | | | | | | |
| | North 10 | 10% | 2 | 0.10 | 1.02 | | | | | | | | |
| 8 | Surface (North) | 15% | 7 | 0.36 | 2.38 | 27,966 | 10,207,454 | 2.08 | 8.8 | 0.1004903 | 1 | 0.100 | 0.256 |
| | New Ventil. Shaft | 4% | 2 | 0.10 | 2.55 | | | | | | | | |
| | Underground South 1 | 4% | 2 | 0.10 | 2.55 | | | | | | | | |
| | Underground South 2 | 12% | 4 | 0.20 | 1.70 | | | | | | | | |
| 9 | Surface | 7% | 4 | 0.20 | 2.91 | 15,980 | 5,832,831 | 1.19 | | | | | 0.204 |
| | -80 | 8% | 3 | 0.15 | 1.91 | | | | | | | | |
| | -80 | 7% | 2.3 | 0.12 | 1.67 | | | | | | | | |
| 10 | Surface | 10% | 5 | 0.25 | 2.55 | 19,975 | 7,291,038 | 1.49 | 6.9 | 0.0787935 | 1 | 0.079 | 0.176 |
| | Underground | 7% | 2 | 0.10 | 1.46 | | | | | | | | |
| | | Surface Total | 49 | 2.50 | | | | 14.58 | | | | | 1.451 |
| | | | | 2.34 | | | | 28 -29 units | | | | | 5.803 |

**Exhibit 1-3: Hebi Gas Drainage and Utilization Figures**

## 1.3 Detailed Background Information on the Hebi Coal Industry Mines

This feasibility study provides a detailed assessment of coalmine methane drainage and end-use opportunities at the Hebi Coal Industry (Group) Corporation's ("HECG") Mine No. 6.

Current mining, ventilation, and methane drainage practices, including drilling, underground gas management and collection, operation of the surface vacuum plants, and the system of gas utilization implemented at Mine No. 6, were evaluated. This evaluation was to determine the feasibility of introducing new methane drainage technology that will enhance drainage efficiency, increase gas recovery, improve recovered gas quality, and provide alternate CMM use options.

The balance of the operating mines of HECG were reviewed to determine if the modern methane drainage practices and technology recommended for Mine No. 6 have broader application, and the potential benefits of these improvements to the balance of the operating mines were quantified.

### 1.3.1 Hebi Coal Industry (Group) Corporation, Limited

HECG is a large enterprise group formed from the Hebi Mining Bureau which was founded in 1957. It is one of 520 national key state-owned enterprises in China, and one of the top 100 industrial enterprises, employing 50,000 and operating under the jurisdiction of the Henan Province.

Located within the confines of Hebi City, the HECG concession borders on Tangyin County on the east, adjacent to Linzhou City on the west, and extends from Qixian County in the south, to Anyang City in the north. The concession lies on the west side of the Beijing- Guangzhou Railway, and Jing-Zhu Expressway and 107 National Highway.

There are two mining areas on the HECG concession, the Hebi and the Xinggong. Currently eight (8) mines are located in the Hebi area while the Xingong area is not exploited. These eight mines, shown on Exhibit 1-2, produce approximately 7 million tonnes of coal per year from mineable reserves in excess of 500 million tonnes. The total coal resource of the concession exceeds 3 billion tonnes. Future coal production, resulting from planned production initiatives and a new mine, No. 11, is projected to be in excess of 16 million tonnes per year in 5 to 10 years. Four of the mines are classified as gassy and four are classed as outburst prone, although all the mines are prone to gas outbursts.

Coal production rates obtained from references and classification through discussions with HECG personnel and others familiar with this mining concession (including information regarding methane drainage trials) and operations, are presented for all mines in Exhibit 1-4.

| Mine | Current Coal Production | Future Coal Production | Classification | Comments |
|---|---|---|---|---|
| | (Mt/y) | (Mt/y) | | |
| No. 2 | Not Operating | | Gassy | |
| No. 3 | 1.2 | 1.5 | Gassy | J-Coal Drilling Project[1] |
| No. 4 | 0.9 | 1.5 | Outburst Prone | HZTM Joint Venture[2] |
| No. 5 | Not Operating | | Gassy | |
| No. 6 | 1.2 | 1.2 | Outburst Prone | Surface gob gas drainage test (ref 2)[3] |
| No. 9 | 0.3 | 0.6 | Gassy | |
| No. 10 | 0.6 | 0.6 | Gassy | |
| No. 11 | Under Development | 1.8 | Outburst Prone | Surface gob gas drainage test (ref 2) |

1. The J-Coal project was a Japanese sponsored project to introduce directional drilling to HECG and involved drilling from underlying galleries into the mining seam to reduce gas contents. Because of stress and gas outburst conditions (over-pressured coal), this project required advancing casing to the coal horizon but was not successful.

2. HZTM is a joint mining venture between a Thailand based mining company (Banpu Group) and HECG.

3. The testing of surface gob gas drainage techniques (vertical gob wells) was not confirmed by HECG in discussions but is presented in Reference 2.

**Exhibit 1-4: Overview of Operating Mines in the Hebi Concession**

### 1.3.2 Hebi Zhongyuan SAKEL Company (HZSAKEL)

HZSAKEL is a joint venture between Sakel International, Inc. and HECG which was formed through private placement funding. The goal of HZSAKEL is to implement modern CMM combustion technology at HECG Mines, sell excess generated power (primarily HECG use), qualify this project as a CDM under Kyoto Protocol, and monetize the carbon credits.

At the time of this study, approximately sixteen 500 kW Chinese-made IC generator sets are installed to combust low quality methane and air mixtures (less than 20 percent by volume) drained from HECG mines. These are co-generation units which supply heating for mine use and staff housing (ref.2).

Site meetings and visits were held between EPA CMOP Contractors, Members of the Board of Directors of HZSAKEL, and HECG personnel, between May 26-28, 2008. Following discussions regarding HECG operations and the joint venture, HECG personnel elected to provide more detailed information regarding mining techniques, and methane drainage and use practices implemented at one of HECG's typical or more accessible mines, Mine No. 6. This mine serves as the basis for this feasibility study. The information gathering process included a visit to the mine offices for discussions with mine engineers (Exhibit 1-5), inspection of one of the two surface ventilation facilities, and the vacuum station and power generation plant.

**Exhibit 1-5: Mine No.6 Offices and Production Shaft**

During the week of July 7, 2008, a subsequent visit to HECG was arranged to collect additional data which was requested following the initial visit, and to directly inspect underground methane drainage practices at Mine No. 6. Following a detailed investigation of the methane drainage and use practices at this operation, recommendations to implement new methane drainage technology will be provided to improve recovered gas quality and quantity.

Using numerical analyses, the impact of these recommendations will be quantified and gas production projections will be generated specifically for Mine No. 6. The costs and impacts of these recommendations and their impact on the practice of mining coal will be quantified. The application of these same recommendations on the other operating mines of HECG will be assessed and an overall benefit projection will be presented.

## 1.4 Evaluation of the Technical Potential for a CMM Project at Hebi Mine No. 6

### 1.4.1 General Mine Data

Mine No. 6, which was commissioned in 1964, produces 1.2 million tons of coal (ROM) per year from two (2) mining districts, each employing two (2) longwalls. The longwalls mine a single coal seam of the Permian Shanxi Formation, Seam $2_1$, which ranges in thickness from 6 to 13 meters (average 8 meters in thickness) across the mining concession. Mining depths range from 300 to 400 meters, and the coal seam dips to the south at approximately 20 degrees.

The mine has been designed for a 100 year life, with main roadways developed in rock above and below the mining horizon, supported by shotcrete with cement roadways, and/or supported by steel arches on 1 meter centers. HECG projects 80 more years of coal production from this operation, thus making it an ideal candidate for a long-term CMM degasification program.

### 1.4.2 Mining Practices

Mine No. 6 is equipped with one production shaft, a men and materials shaft, and three ventilation shafts. The mine is ventilated by an exhaust system of ventilation, with main fans located on surface. The mine's total ventilation airflow rate is approximately 267 $m^3$ per second. Access to the two mining districts is by rail, via the East Main Road, and the South Main Roadways.

Longwall panels are developed with single entry gate roads, on strike and mined in districts off of the two main roadways as shown on the general ventilation configuration map of the mine, (Exhibit 1-6). Note longwall panels 28032, 2121, and 2143, with associated developments of gate entries for subsequent panels off of the East Main Road, and longwall panel 2091 and associated gate entry developments off of the South Main Road.

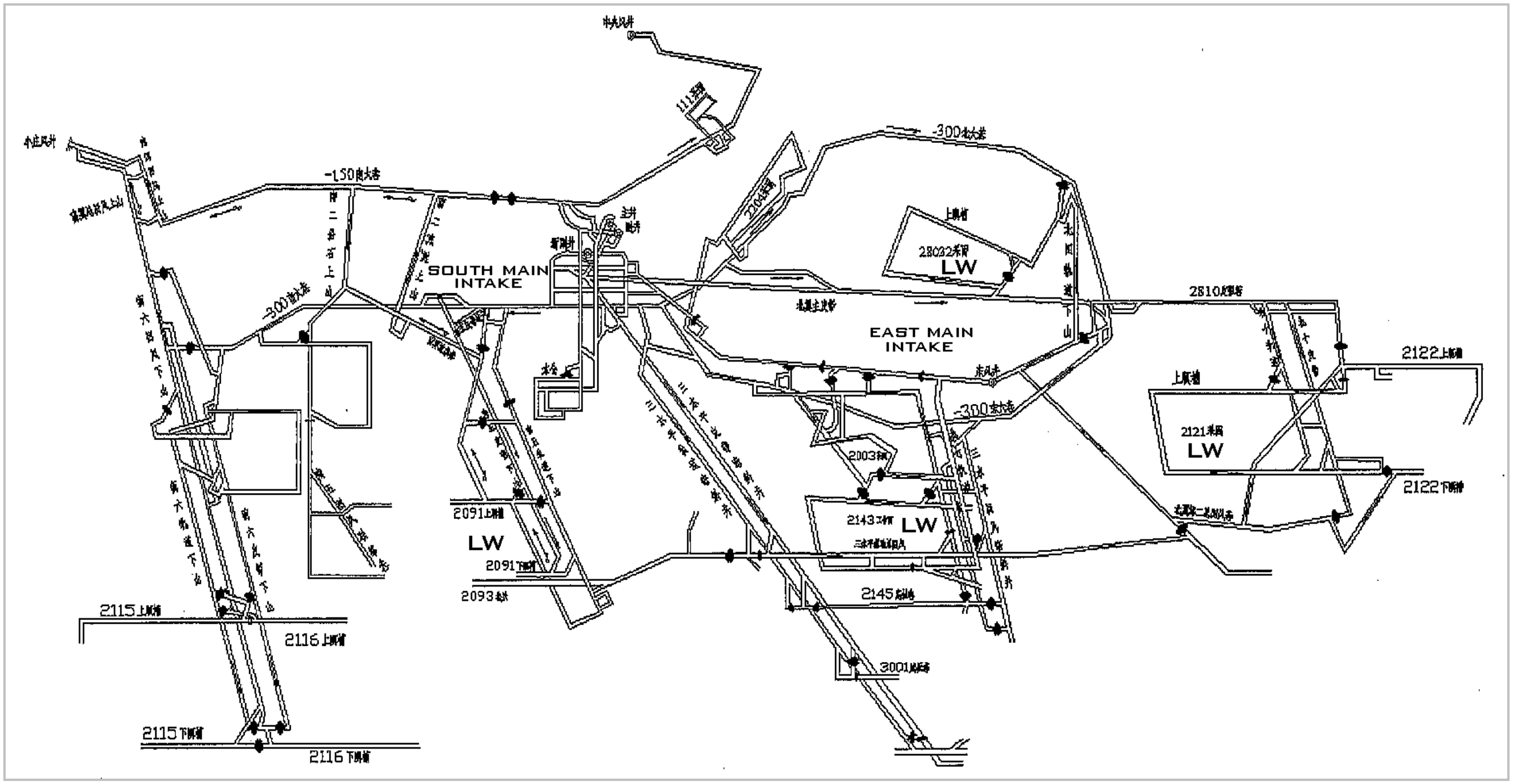


**Exhibit 1-6: General Ventilation Configuration of Mine No.6**
(Source: ref. 4)

Longwall panels are mined using a multi-pass or multi-level bench retreat longwall mining technique. As Seam $2_1$ averages 8 meters in thickness, the longwall panels are mined in three passes or three benches, each approximately 2.5 meters in height starting from the top of the coal seam. Mains and gateroads are driven using drilling and controlled blasting with water based gel techniques. Gateroads are supported by steel arches, lagging, and cribbing. Gateroads are mined in three passes, and re-supported after each split of coal is mined as shown on Exhibit 1-7.

Longwall panels are typically 120 m to 140 m wide by 500 to 1000 m long and are mined over a three (3) year period. Longwalls may not be equipped with mechanized roof supports and shearers and are likely mined by drilling and controlled blasting with some form of mechanized haulage system.

Roadways are developed under the mined seam and panels for materials and coal transport, and they also provide access for fan drilling stations (drilling into the overlying coal seam to reduce gas content in advance of mining), particularly for outburst prone panels. For most longwall panels, ramps are driven above the mining horizon to provide access for gob gas drilling above the mining seam.

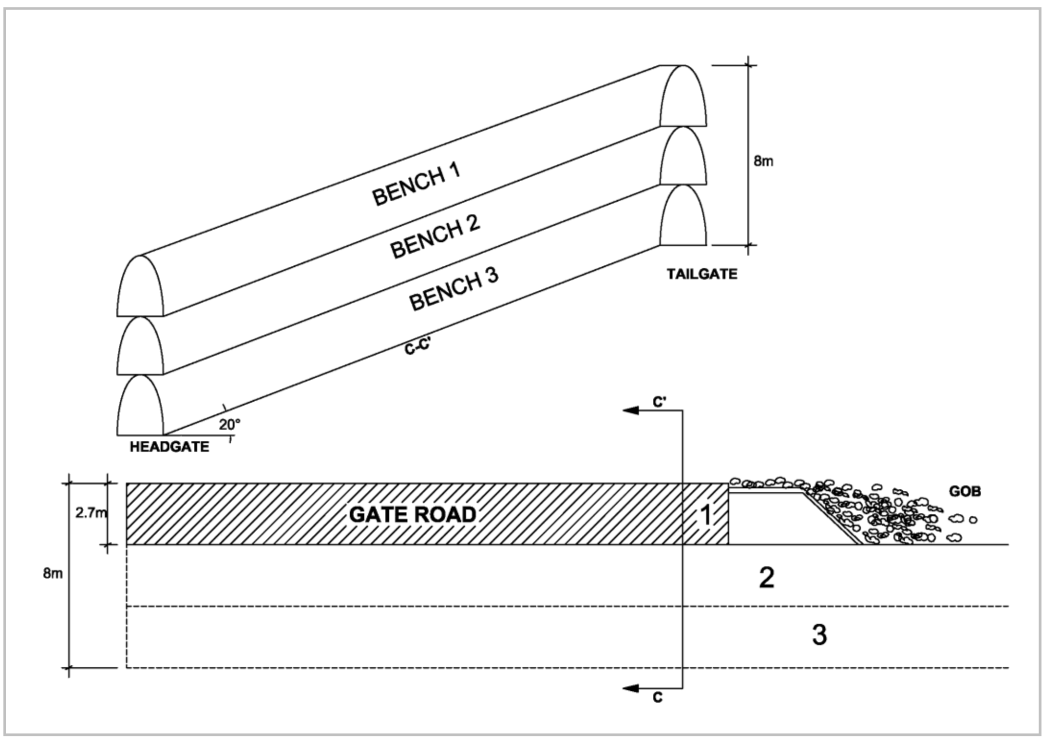


**Exhibit 1-7: Multi-level Branch Retreat Longwall Mining at Mine No.6**
(Source: ref.5)

### 1.4.3 Methane Emissions

As shown in Exhibit 1-8, Mine No. 6 liberates 96,922 $m^3$ of methane per day from its ventilation and underground methane drainage systems pursuant to June 2007 data (ref. 2). Of this volume, 21 percent of the methane emitted is drained. Using these figures, Mine No. 6 specific emissions are calculated at 29.5 $m^3$ per ton. Methane concentrations in ventilation air mixtures at mine ventilation exhaust shafts are less than 0.5 percent, while recovered gas quality from underground methane drainage is less than 20 percent methane in air by volume.

| Source | Methane Concentration (%) | Methane Emissions ($m^3$/day) |
|---|---|---|
| Central Vent Shaft | 0.10 | 1,669 |
| Xiaozhuang Vent Shaft | 0.26 | 20,292 |
| East Wing Vent Shaft | 0.42 | 54,801 |
| Surface Vacuum Station | 18.00 | 20,160 |
| Total | | 96,922 |

**Exhibit 1-8: Mine No.6 Methane Liberation (assumed as measured), June 2007**
(Source: ref.2)

June 2007 (ref. 2) data indicates that 15,806 $m^3$ of methane was utilized, or 78 percent of gas collected from methane drainage; 16 percent of the total methane liberated by the mine is used.

### 1.4.4 Methane Drainage

Entrained water is separated from the gas gathering system on surface inby the vacuum pump by expanding the gas into separators as shown in Exhibit 1-9. The surface vacuum station is equipped with two liquid ring vacuum pumps, each with a capacity of 288,000 $m^3$ of drained gas per day at a vacuum pressure of 16 kPa. Only one pump was running at the time of inspection.

**Exhibit 1-9: Surface Gas Collection and Water Separation (on left), Vacuum Pump (on right)**

Gas from underground methane drainage is transported to a surface vacuum station via an underground pipeline network as generally shown in Exhibit 1-10.

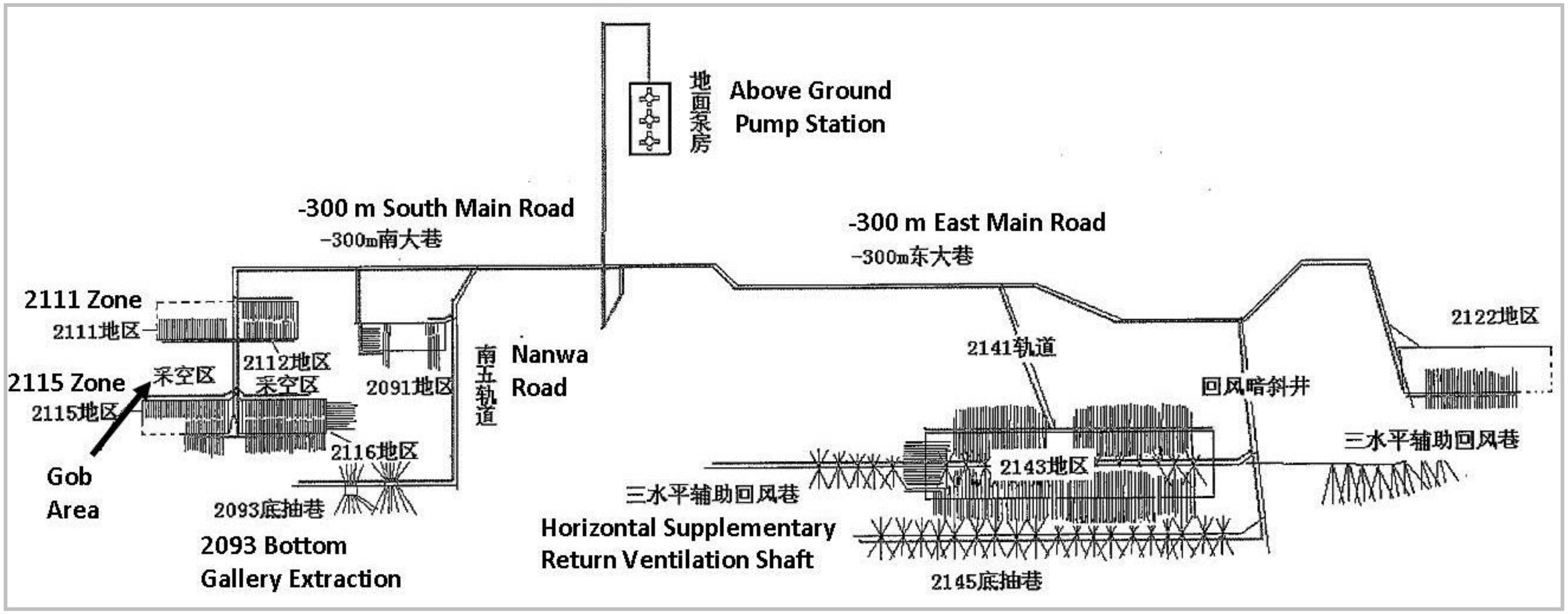


**Exhibit 1-10: Schematic of Underground Gas Collection System at Mine No.6.**

Monitoring equipment installed inby the vacuum pump includes an optical sensor for concentration measurements, a flow meter, and a temperature transducer. Instrument displays are recorded every 30 minutes by hand on a daily log.

Exhibit 1-11 and Exhibit 1-12 show averages of daily methane concentration and methane flow rate data obtained for the first five (5) months of 2008 at the surface vacuum station based on standard conditions (STP), while Exhibit 1-13 and Exhibit 1-14 illustrate the daily variance in methane flow rate and methane concentration over this period. Note that the average methane drainage rate for the first five months of 2008, 23,000 $m^3$ per day at standard conditions, is consistent with the average methane flow rate reported for June 2007 presented in Exhibit 1-8 (20,160 $m^3$ per day assumed as measured), and that daily variations in methane concentration drop to as low as 17 percent by volume.

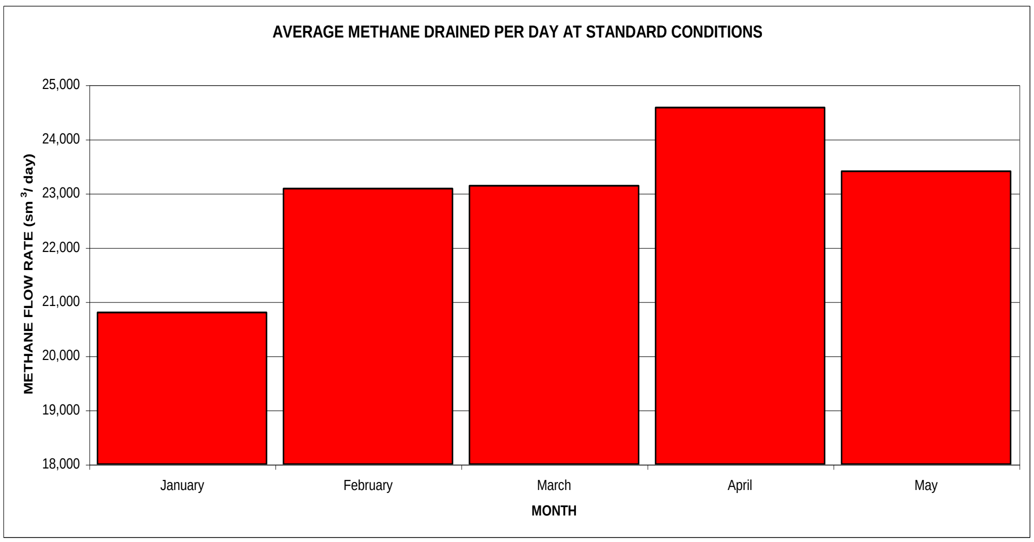


**Exhibit 1-11: 2008 Average Daily Methane Flow Rate by Month from Vacuum Station, at Standard Conditions**
(Source: ref. 4)

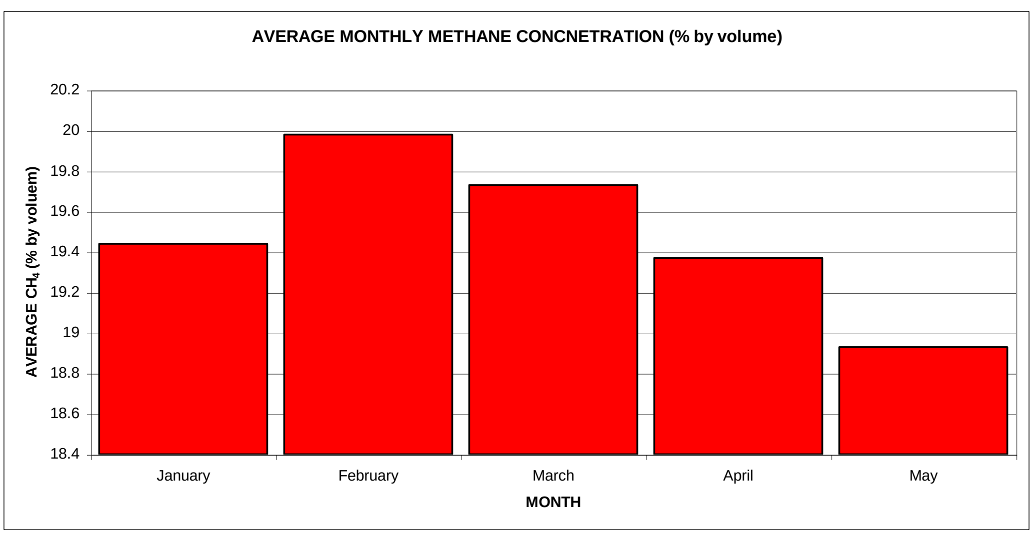


**Exhibit 1-12: 2008 Average Monthly Methane Concentration Measured at Vacuum Station**
(Source: ref. 4)

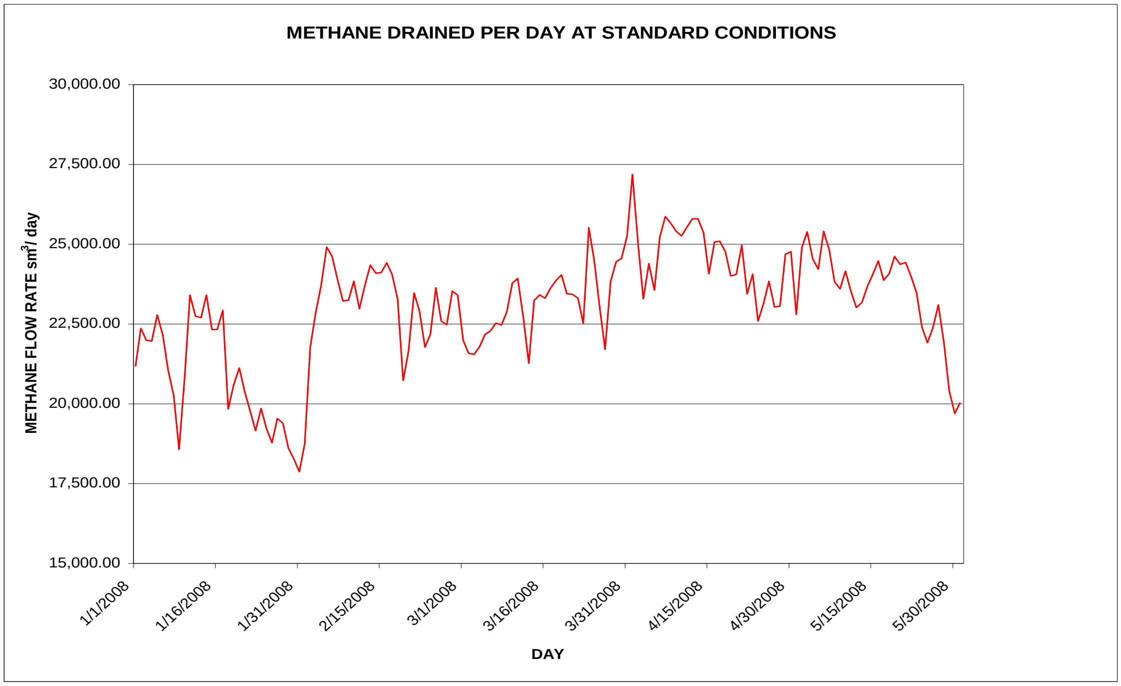


**Exhibit 1-13: 2008 Daily Variance in Methane Flow Rate at Vacuum Station, at Standard Conditions**
(Source: ref. 4).

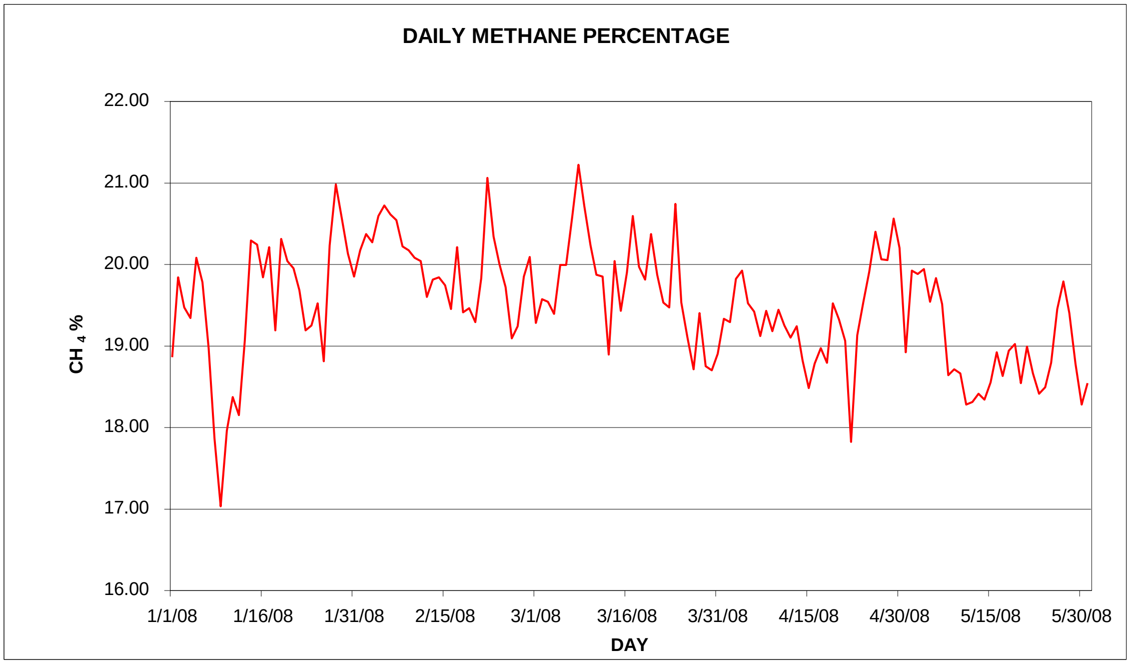


**Exhibit 1-14: 2008 Daily Variance in Methane Concentration Measured at Vacuum Station**
(Source: ref. 4)

Mine No. 6 is forecast to increase underground methane drainage rates for further power generation capability, as shown in Exhibit 1-15, by implementing improved drainage techniques (ref. 2). An 18 percent increase in the methane drainage rate is projected from 2008 to 2010.

| Year | Methane Drainage Rate ($m^3$/day) |
|---|---|
| 2007 | 24,657 |
| 2008 | 26,027 |
| 2009 | 30,137 |
| 2010 | 30,685 |

**Exhibit 1-15: Projected Increase in Methane Drainage Volumes for Mine No. 6 (assumed as measured).**

### 1.4.5 Source of Emissions

Mine personnel indicate that the primary sources of methane emissions at Mine No. 6 are the mined seam (Seam $2_1$) and the gob areas (approximately 25 percent of the gas drained is recovered from the gob). Because of the proximity of adjacent coal seams (Seam $1_1$), the source of the gob gas is likely to be, to a small degree, charged adjacent sandstones, but primarily coal left in the gob due to the technique of mining (coal left in lower benches to be mined in subsequent passes). Longwall mining relaxes this remnant coal resulting in fractures which provide conduits for residual adsorbed gas that was not drained in advance of mining.

Exhibit 1-16 indicates that for the first four months of 2008, approximately 40 percent of the methane liberated by the mine's ventilation system was emitted at the four longwall sections, panels 2803, 2143, 2003, and 2121. The balance of emissions, approximately 48,000 $m^3$ per day, is emitted from mine developments and sealed gob areas of the mine.

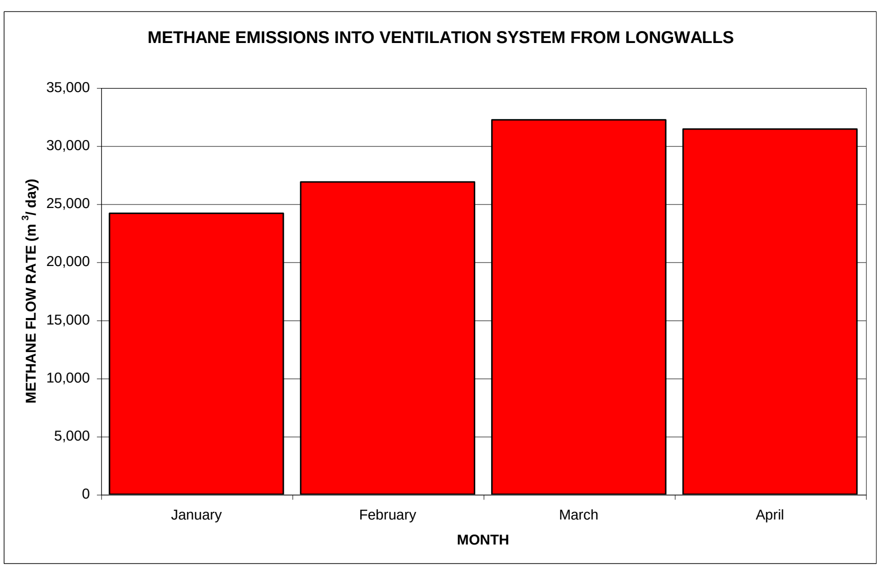


**Exhibit 1-16: Average Daily Methane Emitted by Mine #6 Longwalls by Month, 2008**

### 1.4.6 Methane Use Practices

Located adjacent to the surface vacuum station is a power generation plant equipped with five Shengli Oilfield Company (Shandong) generator sets. These units are modified to operate on low quality gas, but are high maintenance units that generally produce approximately 300 kW of power on an average monthly basis. Waste heat from the generator sets is employed to heat water for mine use and staff housing (ref. 2).

The power plant is electronically monitored and data is displayed at a central monitoring location in the plant. Exhibit 1-17 shows a Shengli Oilfield Company generator set and waste heat cooling towers employed at Mine No. 6.

**Exhibit 1-17: 500 kW Shengli Oil Company Generator Set and Waste Heat Recovery at Mine No. 6.**

Power generated is for self use; the 5 generator sets satisfy approximately 50 percent of the power requirements of Mine No. 6. Presently the majority (78%) of all the gas drained at Mine No. 6 is used for power generation (ref. 2).

### 1.4.7 Mine Ventilation Fans

Mine No. 6 employs an exhaust system of ventilation with the main fans at the surface. Surface fan infrastructure is in good condition (with minor air leakage) and suitable for modification of slip-streaming ventilation exhaust for recovery of ventilation air methane (Exhibit 1-18).

**Exhibit 1-18: Main Surface Fan Infrastructure at Mine No. 6.**

Each fan house is equipped with one operating and one standby main mine fan with an operating capacity of 168 $m^3$/s of airflow, at a fan total pressure of 4,242 Pa.

The main fan housing with monitoring equipment, and electric motor used to drive the fan in the control room, is shown in Exhibit 1-19.

**Exhibit 1-19: Fan Housing with Sensors (left) and Electric Motor (right).**

### 1.4.8 Conclusions

After reviewing the data, it was determined that Mine No. 6 would make a good project site for the following reasons:

- The coal seams have a relatively high in-situ gas content (14-22 $m^3$/ton);
- Mining is performed using longwall production systems, which produce significant gob gas emissions;
- Degasification systems, although limited, are currently in place and there is room to greatly expand these systems (Exhibit 1-3).
- The mine operators are currently utilizing some of the produced CMM by producing power (< 1 MW) and would like to expand power production. They are using Shengli Oilfield Company reciprocating generating sets (also referred to as Shandong). These are 500 kW units that have a high maintenance requirement, which reduces their monthly output to the equivalent of about 350 kW. There are 5 units currently in place and all generated power is used by the mine. National Grid power lines are located approximately one mile from the mine and one of the goals of the study will be to evaluate the viability of selling any excess power generated by the mine into the National Grid. If that is accomplished, there would be a significant bonus for power that is generated.
- Mining plans are in-place to double coal production over the next 5 years which will concomitantly increase methane emissions. Current and projected methane emissions for the Hebi coal mining area are shown in Exhibit 1-20.

**Hebi Mines Projected Methane Emission Increases**
(Based on expected increases in coal production)

| | Increased Methane Production, 10,000s $m^3$/year | | | | |
|---|---|---|---|---|---|
| **Mine** | **2008** | **2009** | **2010** | **2011** | **2012** |
| 3 | 200 | 260 | 300 | 300 | 300 |
| 4 | 300 | 400 | 500 | 500 | 500 |
| 6 | 500 | 600 | 700 | 700 | 700 |
| 8 | 200 | 220 | 300 | 300 | 300 |
| 9 | | | 100 | 200 | 200 |
| 10 | 150 | 170 | 200 | 200 | 200 |
| **Total** | **1350** | **1650** | **2100** | **2200** | **2200** |

**Exhibit 1-20: Hebi Mines Projected Emissions Increases**

## 1.5 References

1. Introduction of Hebi Coal Industry Group Ltd. Choy, June 6 2008 e-mail.

2. Brief Introduction to Basic Situation of CBM/CMM Exploitation in Hebi Coal Industry (Group) Corporation Limited. Communication with Hebi Mine Administration, 2008.

3. Response to initial data request. May, 2008.

4. Response to last data request dated June 5 2008

5. Responses to data clarification dated November 24 2008

## 1.6 Appendices

### 1.6.1 Appendix 1A

**Hebi Questionnaire**

Resource Enterprises Inc. and Advanced Resources International have been asked to perform a feasibility study for the Methane to Markets program. We are in the process of selecting a candidate mine for this study. The following information will be very useful in guiding the selection of a candidate mine. Please provide thorough answers to the following questions.

1. Location

    1.1 Location and mining area

2. Geologic and Reservoir Characteristics

    2.1 General Stratigraphy
    2.2 Is the area heavily faulted?
    2.3 Coal seam thicknesses, depths, etc.
    2.4 Coal rank and coal quality data in mining area
    2.5 Gas content of coal seams.
    2.6 Mechanical property information of coal seams and surrounding strata. Hardness, friability, etc.

3. Coal Production

    3.1 Mining method-longwall vs room and pillar
    3.2 Number of working faces or longwall panels
    3.3 Current coal production of mine

4. Ventilation Data

    4.1 Ventilation method
    4.2 Mine ventilation volume

5. Gas Emission Data

    5.1 Volume of gas recovered, volume vented
    5.2 Outburst conditions-yes or no
    5.3 Source of gas emissions—active face or gob

6. Gas Drainage

    6.1 Gas drainage methods
    6.2 Recovered gas quality

7. Coalbed Methane Utilization

    7.1 Amount of gas utilized by year
    7.2 Gas utilization potential

### 1.6.2 Appendix 1B

**Feasibility of Improved Coal Mine Methane Drainage and Use
at the Mines of the Hebi Coal Industry (Group) Corporation, Limited**

**Information Request, June 5, 2008**

The following information request was derived from the initial reconnaissance visit to the Hebi Coal Industry (Group) Corporation Limited, performed between the 26th and 27th of May, 2008 (with specific focus on Mine 6).

Mine 6, Detailed Information Requested for Feasibility Study:

1. All 2008 daily (typically recorded every half-hour) methane drainage system monitoring data, specifically % methane, line pressure, gas flow rate, and temperature, at the following locations:
   - At above ground vacuum pump station (total one)
   - At each monitoring location underground along the gas collection system (outby longwall areas 1 – 4 and any other location where this is performed)
   - Up-stream of the exhaust ventilation fan (2 exhaust shafts for Mine 6)
2. All daily (typically recorded every half-hour) methane drainage system monitoring data for two complete separate months for each of the years 2005 through 2007 (for example January and June of each year), specifically % methane, line pressure, gas flow rate, and temperature, at the following locations:
   - At above ground vacuum pump station (total one)
   - At each monitoring location underground along the gas collection system (outby longwall areas 1 – 4 and any other location where this is performed)
   - Up-stream of the exhaust ventilation fan (2 exhaust shafts for Mine 6)
3. All daily (typically recorded every half-hour) ventilation system monitoring data for 2008 and two complete separate months for each of the years 2005 through 2007 (for example January and June of each year), specifically % methane, static pressure, and airflow rate at the following locations:
   - At each monitoring location underground (outby longwall areas 1-4 and any other location where this is performed)
   - up-stream of each ventilation exhaust fan (2 exhaust shaft locations for Mine 6).
4. Gas production as a function of time from a single or group of methane drainage boreholes obtained from tests performed, or from gas flow predictions derived by Research Institutes for:
   - Cross-panel boreholes
   - Boreholes drilled from galleries developed under the mined seam
   - Gob boreholes drilled above the mined seam (Laotong)
   - Pipe in gob systems
5. Reservoir characteristics of mining seam obtained from tests (Research Institutes, etc.):
   - Gas content (volume/tonne) and variation in mining areas for Mine 6
   - Gas compositon

- Coal permeability
- Coal cleat or natural fracture orientation
- Cleat spacing
- Coal characteristics (mechanical properties)

6. Geologic Characteristics
   - Legible geologic column identifying strata 100 m above the mining seam and 20 m below the mining seam
7. Mine plan for Mine 6 illustrating:
   - Underground pipeline layout
   - Ventilation airflows
   - Current mining areas
   - Future mining plans
8. Clarification of Multi-pass Longwall Mining Method
   - Gate roads are driven in upper coal bench
   - Are the gate roads advanced to a lower elevation and re-supported prior to each subsequent longwall pass?

### 1.6.3 Appendix 1C

**Feasibility of Improved Coal Mine Methane Drainage and Use
at Mine No. 6 of the Hebi Coal Industry (Group) Corporation, Limited**

**Information Request No. 2, January, 2009**

The following subsequent information request (No. 2) was derived after two reconnaissance visits to the Hebi Coal Industry (Group) Corporation ("HCIG") (including an underground tour of Mine No. 6), and an analysis of the responses received from HCIG to the initial information request dated June 5, 2008. Note that some of the information requested below was previously requested but not received.

A. Information regarding the distribution of methane emissions into the Mine No. 6 ventilation system, specifically:

1. Any daily (typically recorded every half-hour) ventilation system monitoring data for 2008 and two complete separate months for each of the years 2006 through 2007 (for example January and June of each year), specifically % methane, airflow rate, and temperature at the following locations:
   - Bottom of the Central Ventilation shaft or through mine fan;
   - Bottom of the Xiozhuang ventilation shaft or through mine fan, and;
   - Bottom of the East Wing ventilation shaft or through mine fan.
2. Methane emissions data from operating longwalls provided by HCIG (2006, 2007, and 2008) indicate that longwall districts (zones) contribute to 40% of methane emissions into the Mine's ventilation system. This leaves 60% from mining developments (gateroads and other developments in coal) and sealed areas. Specifically, where is this balance of emissions (60%) from?

3. Please provide a general stratagraphic column showing thickness and distance of overlying and underlying formations, especially sandstones, shales, and coals, relative to the mining seam 21.

B. Information regarding the distribution of gas flows in the underground gas collection system at Mine No. 6, specifically:

1. Any daily gas flow rate, % methane, pressure, and temperature data for 2008 (daily data for several months would suffice) at monitoring locations underground along the gas collection pipeline system.
2. We assume that the two Nansi pump stations are located underground. Where are they located (they are not shown on the underground pipeline schematic provided by HCIG) and which mining areas do they serve? Are there any other pump stations underground? Are they specifically for drawing low quality methane from extraction pipes in the gob (gas quality is very low)? Are there separate pipelines that carry the low quality gob gas to the Nansi pumps?
3. We understand that there is one pump station on surface and assume that pump stations in North Wing, North 7, and North 10 are underground. Two of these are Nansi pump stations what is the third pump station? Is there another surface pump station?

C. Information regarding the amount of gas drained from underground methane drainage systems at Mine No. 6, specifically:

1. Typical gas or methane flow rates were provided for all systems of methane drainage except for the cross-panel boreholes. Please provide typical gas flow rate or methane flow rate from a cross-panel borehole drilled in longwall panels off of East Main Road, and South Main Road.
2. Provide a typical gas production rate from a cross-panel borehole as a function of time.
3. Please provide an estimate of the distribution of gas collected from underground by all of the systems of methane drainage implemented at Mine 6, specifically:

| System | % of total gas drained | % of total methane drained |
|---|---|---|
| Face drainage | | |
| Gallery drainage (boreholes under the coal) | | |
| Cross-panel drainage boreholes | | |
| Overlying gob boreholes | | |
| Pipe extraction systems in gob | | |

4. What were the results of surface vertical gob well tests conducted at Mine No. 6.?

D. Coal production and methane drainage for Mine No. 6, specifically:

1. Approximately how long does it take to drive the headgate and tailgate entries to outline a typical longwall panel?
2. For a typical panel, are the headgate and tailgate entries driven one at a time as shown on the pipe network layout plan provided or at the same time?

3. Once the longwall panel is outlined by the headgate and tailgate entries, the panel is drained for an additional 6 to 9 months prior to mining – correct?
4. Please provide the coal production forecast for Mine No. 6 for the next 10 years.
5. Please provide the gas drainage production forecast for the next 5 years.
6. What is the projected life of this mine?

E. Information to assess the feasibility of using Ventilation Air Methane for Mine No. 6, specifically:

1. Performance curve (Fan total Pressure versus Airflow) for each of the mine fans on the three ventilation exhaust shafts, Central, Xiozhuang, and East Wing.
2. Current price the Mine is paying for power RMB 0.50/kWh?
3. Map showing distances between surface gas drainage station and mine exhaust shafts.
4. Typical composition of air exhausted from mine fans, specifically other gases, moisture content, and particulate matter.
5. Temperature of the air exhausted from mine fans, minimum and maximum, and average.
6. Weather conditions at fan site, average, minimum and maximum, temperature, humidity, and rainfall.
7. Available electrical capacity at the fan sites (kW).
8. Availability of natural gas or propane at fan sites.
9. Availability of water at fan sites. If water needs to be brought in then cost of transport.
10. Existing communications between exhaust fan sites and mine central control room.

F. General information regarding other mines of HBIC, specifically:

1. Please correct and complete the attached table of other mines of HBIC.

| Mine | Current Production | Target Coal Production Rate | Classification | Comments |
|---|---|---|---|---|
| | (Mt/y) | (t/y) | | |
| No. 2 | Not Operating | | Gassy | |
| No. 3 | 1.2 | 1.5 | Gassy | J-Coal Drilling Project |
| No. 4 | 0.9 | 1.5 | Outburst Prone | HZTM Joint Venture |
| No. 5 | Not Operating | | Gassy | |
| No. 6 | 1.2 | 1.2 | Outburst Prone | Surface gob gas drainage test (ref 2) |
| No. 8 | | | | |
| No. 9 | 0.3 | 0.6 | Gassy | |
| No. 10 | 0.6 | 0.6 | Gassy | |
| No. 11 | Under Development | 1.8 | Outburst Prone | Surface gob gas drainage test (ref 2) |

# SECTION 2

# Geologic Overview and Resource Assessment

# SECTION 2 CONTENTS



# SECTION 2 EXHIBITS

## 2.1 Introduction

The regional and local geology of the Hebi area was studied as part of the evaluation of coal formation, structure and properties in the Hebi Coal field. Analysis of the coal data, along with borehole and gas content data, provided confirmation of the size and distribution of the methane resource base available for recovery and utilization.

## 2.2 Regional Geologic and Tectonic Setting

The geologic history of the Hebi mining area is complex and has created reservoir conditions that are significantly different from many of the coal basins in the U.S. The geology of this area is more similar to the tectonically active Western Washington Basin than the relatively cratonically stable Appalachian, Black Warrior, and San Juan Basins where the majority of U.S. CBM and CMM projects have been developed. As a result, CMM and CBM development in the Hebi area needs to consider several unique factors affecting the methane potential of the area, such as a major unconformity close to the coal seams and the modern tectonic environment, in addition to standard resource in place and permeability analyses.

The Hebi mine area is located within a series of small, fault-bounded Paleozoic coal basins in North-Central China. These Paleozoic coal basins comprise the Taidong coal region and have been disrupted by the opening of the North China Basin, which is still actively undergoing extension (Exhibit 2-1).

The primary coal-bearing units in the Taidong coal region are the Early Permian Shanxi and Late Carboniferous Taiyuan Formations, which occur in a 200+ meter (m) thick sequence of alternating transgressive and regressive coal seams, shale, and shaly sandstone deposited in a stable platform environment (Exhibit 2-2). This tectonic environment changed during late Triassic time, as block faulting created NE-SW oriented folding and thrusting of the Paleozoic sequence, forming the structural foundation seen today in the Hebi area and creating an extensive denudation surface.

The tectonic environment profoundly changed again after Eocene time (50 Ma), as the modern North China Basin began to open by intra-plate rifting. The Hebi region lies along the western margins of this actively forming basin in the piedmont zone of the Taihang Mountains, and began to subside during Quaternary time (about 2 Ma). A great thickness of Quaternary sediments, up to 1,000 m in some parts of the basin, directly and unconformably overlies the coal-bearing Paleozoic sequence, indicating that subsidence in the basin has been recent and extremely rapid. The denudation and subsidence recorded by the Paleozoic-Quaternary unconformity is believed to have had a significant impact on the coalbed methane potential of the mine area and is discussed separately below.

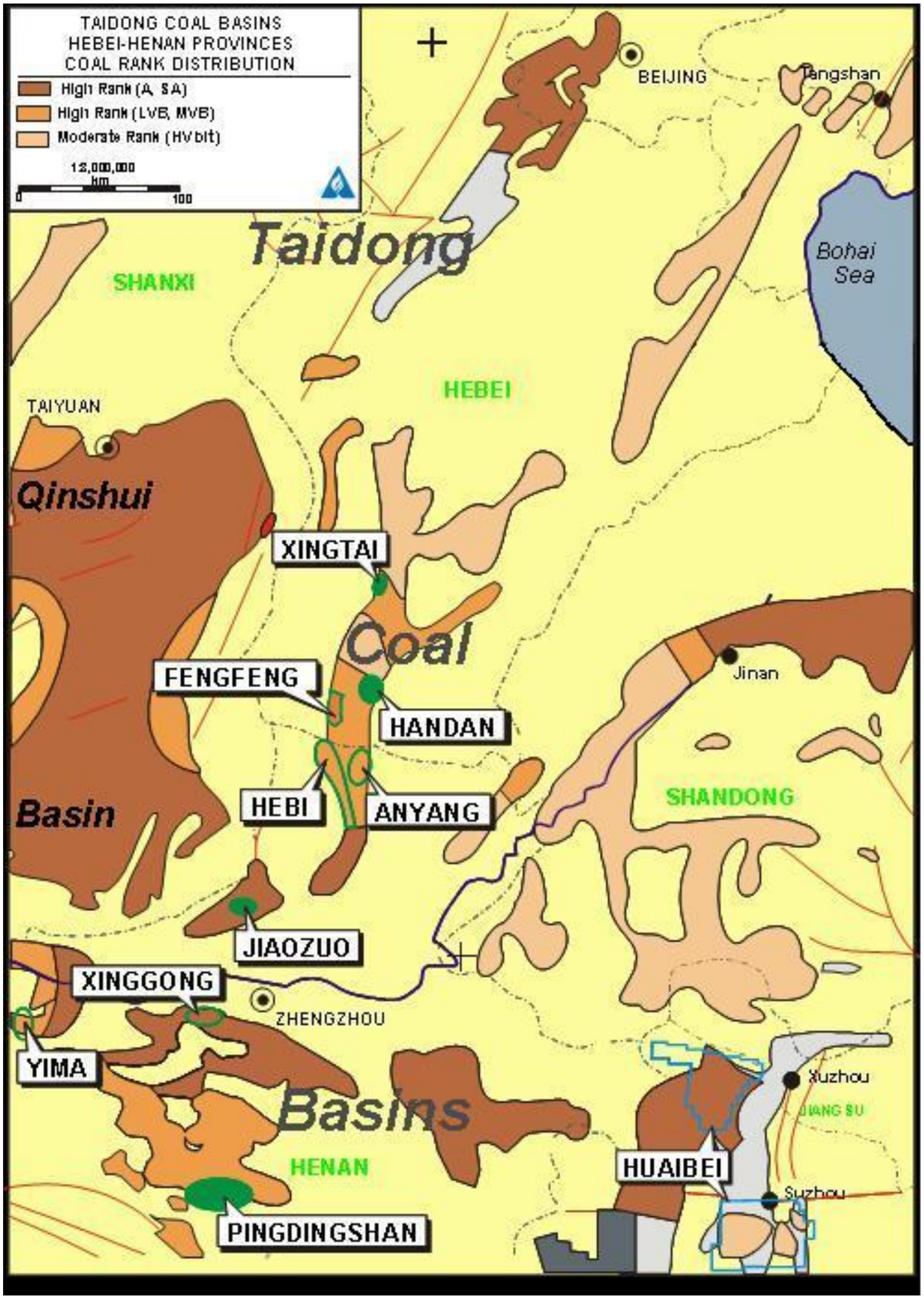


**Exhibit 2-1: Taidong coal region basins and rank distribution map**

## Coal Rank

- High-vol bituminous at Pingdingshan
- Lov-vol bituminous at Xingtai, Fengfeng, Handan, Hebi, Anyang.
- Anthracite at Jiaozuo and Zhengzhou

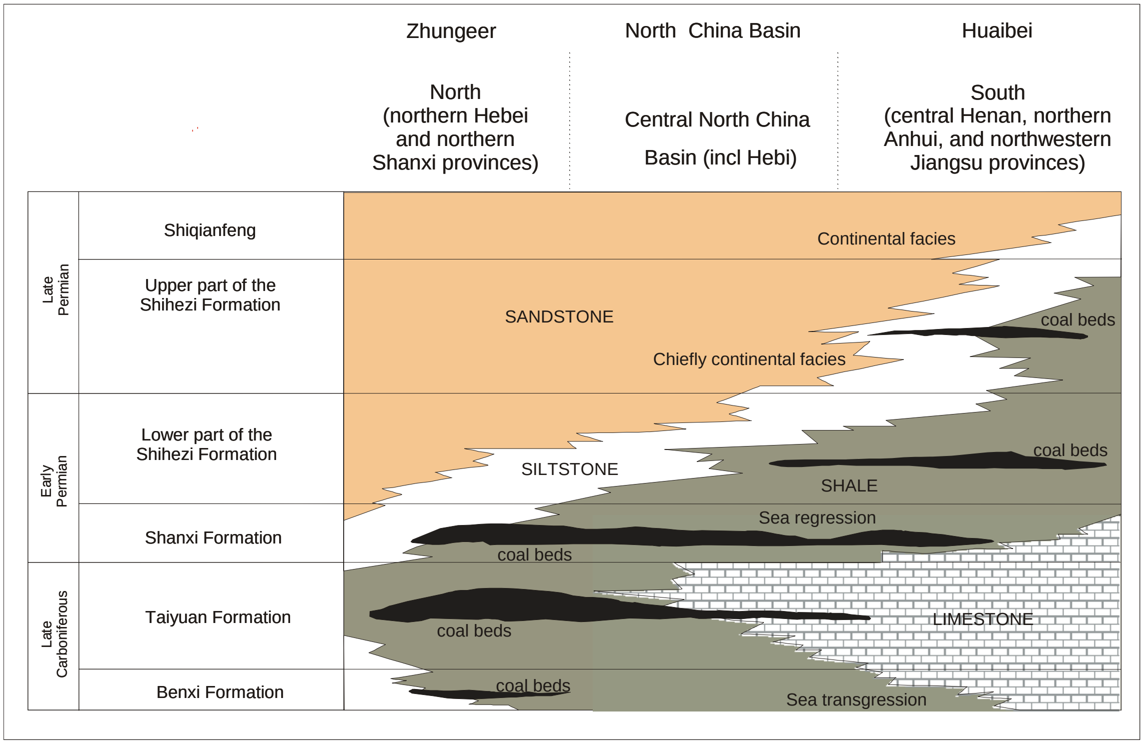


**Exhibit 2-2: Coal lithofacies distribution, East China**

Although the Hebi area is located in an active extensional environment, as the North China Basin continues to open, significant strike-slip faulting occurs locally and probably dominates the stress environment of the mine area (Exhibit 2-3). The neotectonic activity of the North China Basin is demonstrated by the Tangshan Fault, an active dextral transcurrent fault responsible for the devastating 7.8-magnitude earthquake of 1976. Seismic focal-plane solutions inferred from first-motion measurements can also indicate stress conditions. A study of more than 250 aftershocks of the 1976 earthquake showed that regional stress orientation varies both laterally and with depth:

- Earthquakes deeper than 18 km reflected nearly pure right-lateral strike slip. Therefore, vertical stress (Sv) > horizontal stress (Sh), where h = east-west (ew) or north-south (ns) stress.
- Earthquakes at depths of 13 to 18 km showed a combination of strike-slip and normal faulting, indicating some N-S extension. Sew > Sv > Sns.
- Earthquakes at depths from 10 km to shallower than 3 km, in the depth range of the coal seams at the test wells, showed thrust faulting indicative of E-W compression. Sew > Sns > Sv.

These data suggest that the shallow crust (10 km deep) in the North China basin is undergoing overall E-W compression. However, the resolution of seismological data is too low to confidently forecast the stress regime in the relatively small test area, since stress can change markedly across faults and other geologic discontinuities.

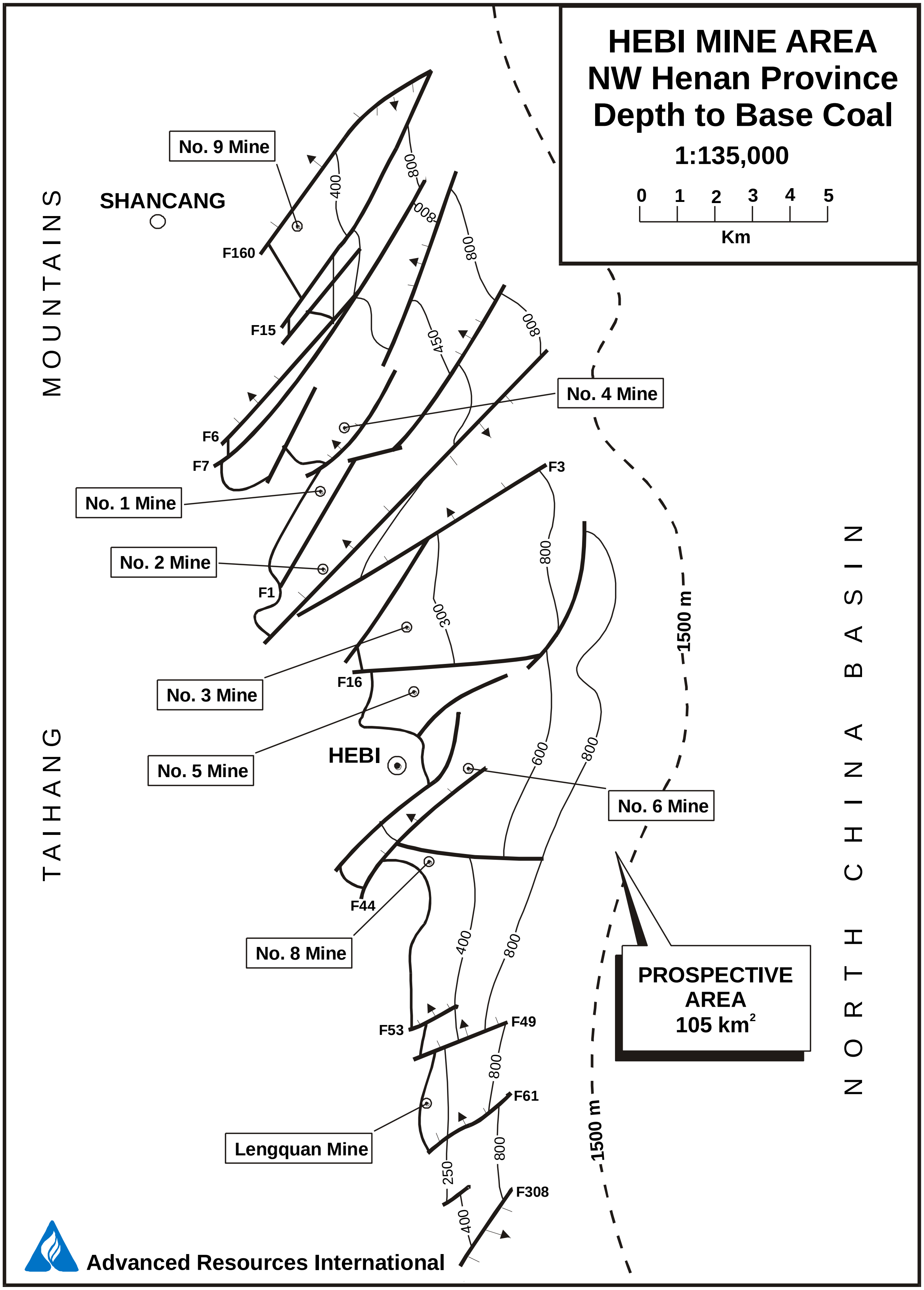


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**Exhibit 2-3: Hebi mine area with mine locations**

## 2.3 Hebi Mine Geology and Resource Assessment

### 2.3.1 Mine area description

The coal seams in the Hebi mining district are distributed in a relatively narrow 80 km long north-south striking band. The width of the mine area varies from 1.5 to 5.2 km in an oblique east-west direction. There are two main mining areas affiliated with the Hebi Coal Mining Group, the Hebi mining area and the Xinggong mining area. These two mine areas encompass an area of about 810 $km^2$, of which the Hebi mine area encompasses 210 $km^2$ and the Xinggong area 600 $km^2$. The principal mined coal seam in the Hebi area is the $2_1$ seam, which has a total resource of nearly 8 billion tonnes. The Xinggong mine area has a total coal resource base of 3.6 billion tonnes, the bulk of which are located in undeveloped areas. Depth wise, there are about 806 million tonnes of reserve down to a depth of 800 m, 251 million tonnes between 800 m and 1,000 m, and 628 million tonnes between 1,000 and 1,500 m.

### 2.3.2 Stratigraphy

The Hebi No.6 Coal Mine is covered by Tertiary and Quaternary sediments. The mid-Ordovician Majago limestone outcrops in the west side of the coal mine. The strata within the coal mine are described below following a chronological order from the oldest to the youngest (Exhibit 2-4):

**Ordovician Period**

- **Lower Ordovician Series ($O_1$)**

  This series consists of very thick, greyish white, medium-grained crystalline dolomite, medium thick chert bearing dolomite, and fine grain crystalline dolomite. The total thickness is about 170m. It lies unconformably above the upper Cambrian.

- **Middle Ordovician Series ($O_2$)**

  This unit is an important consideration in any CMM/CBM drilling program because contacting this unit either directly through a wellbore or indirectly through hydraulic fracturing could render a project uneconomic because of high water flow rates. These rocks consist of medium to very thick limestone and brecciated limestone. Based on the lithology, it can be divided into seven sections. The total thickness is about 397-492 m. It is also the main aquifer within the coal mine. It unconformably overlies the lower Ordovician ($O_1$) series.

| Layer | Accum. Depth (m) | Layer Thickness (m) | True Thickness (m) | Lithology Column 1:200 | Lithology Description |
|---|---|---|---|---|---|
| Shanxi Formation | 550.67 | 8.10 | 7.66 | | GREY sandy mudstone, compacted, with higher fraction of sand, with plant fossil fragments |
| | 553.17 | 2.50 | 2.37 | | GREY silty mudstone, with quartz and feldspar as majority, argillaceous cementation |
| | 557.37 | 4.20 | 3.97 | | GREY and dark GREY sandy mudstone, with plant fossil and high portion of sand, breeze and carbon substance on layer surface and ferruginous mugstone at layer bottom |
| | 561.67 | 4.30 | 4.07 | | GREY silty mudstone ($S_9$), with quartz and feldspar as majority, red mica at layer top and dark mineral, siliceous cementation |
| | 563.47 | 1.80 | 1.70 | | Dark GREY sandy mudstone, weakly compacted, with higher fraction of plant fossil fragments |
| | 564.47 | 1.00 | 0.95 | | Dark GREY silty mudstone, with quartz and feldspar as majority, siliceous cementation |
| | 567.17 | 2.70 | 2.55 | | Dark GREY sandy mudstone, weakly compacted, with higher fraction of plant fossil fragments |
| | 575.49 | 8.32 | 7.87 | | Seam 2 - 1 BLACK coal layer, powdered and massive, with glassy lustre |
| | 578.20 | 2.71 | 2.55 | | BLACK sandy mudstone, compacted, with higher fraction of plant roots fossil fragments |
| $P_1^1$ | 589.60 | 11.40 | 10.71 | | GREY and Brownish GREY silty mudstone ($S_{10}$), with quartz and feldspar as majority, minor white mica fragments. Carbon on layer top and plant fossil fragments and calcareous cementation |
| Taiyuan Group | 593.40 | 3.80 | 3.57 | | Dark BLACK sandy mudstone, compacted |
| $C_3$ | 597.40 | 4.0 | | | GREY silty mudstone, with quartz and feldspar as majority and minor white mica fragments. Calcareous cementation |

**Exhibit 2-4: Hebi mine area stratigraphic column**

**Carboniferous Period**

- **Mid-Carboniferous Benxi Group ($C_2$)**

This unit consists of light grey and purplish grey, aluminum rich mudstone, grey sandy mudstone, light grey sandstone, and thin limestone. Locally, it contains a thin, unmineable coal seam. The total thickness ranges from 18-40 m. It lies unconformably above the Middle Ordovician Series ($O_2$).

- **Upper Carboniferous Taiyuan Group ($C_3$)**

The Taiyuan Group consists of grey and greyish brown sandstone, dark grey and greyish black mudstone, sandy mudstone, limestone, and coal layers. It contains 6-9 limestone layers. Among them the second and the eighth layers are the best developed. This group contains the No. 1 coal seam. Its middle and lower parts, the No. $1_1$ coals, are minable. The No. $1_2$ coals are not as well developed but are locally minable. The rest of the No. 1 series coals are not minable. The total thickness of the Taiyuan group is 115-167 m. It is conformable with the underlying Benxi group.

**Permian Period**

- **Lower Permian Shanxi Formation ($P_1$)**

The Shanxi Formation consists of grey to greyish brown sandstone, grey to greyish black sandy mudstone, and mudstone. At the top of this formation is a purplish red aluminum rich mudstone. At the lower part of this formation, is the very well developed No. $2_1^1$ coal layer. This coal seam has a simple structure and a stable thickness. The total thickness of this formation is 74-110 m. It contacts the underlying Taiyuan group with conformity.

- **Lower Permian Lower Shihezi Formation ($P_1^2$)**

It consists of greyish green sandstone, grey to greyish purple sandy mudstone, and purplish spotted mudstone. The total thickness is about 78-122 m. It contacts the underlying Shanxi formation with conformity.

- **Upper Permian Upper Shihezi Formation ($P_2^1$)**

It consists of greyish white and light greyish green sandstone, grey sandy limestone, greyish purple and purplish spotted mudstone, and mudstone. The total thickness is 350-590 m. It contacts the underlying lower Shihezi formation with conformity.

- **Upper Permian Shiqianbeng Formation ($P_2^2$)**

It consists of purplish red and dark purple mudstone, sandy mudstone, and fine grain sandstone. The thickness is greater than 1,000 m. It contacts the underlying upper Shihezi formation with conformity.

**Neogene Period (N)**

It mainly consists of sandy clay, clay , conglomerate, and fresh water limestone. In the north part of the coal mine the fresh water limestone is better developed. In the south, the conglomerate is better developed. The thickness increases gradually from the west side of the coal mine to the east side of the coal mine. The average thickness is about 180 m. It contacts the underlying Permian period with angular unconformity.

**Quaternary Period (Q)**

Quaternary sediments mainly consist of conglomerate and clay found mostly in valleys. The thickness varies from 0-32 m. It is unconformable with the underlying Neogene sediments.

### 2.3.3 Structure

The Hebi No.6 Coal Mine is located at the east side of the south end of the Taihang Shan Uplift. The west side of this coal mine abuts against the east slope of the Taihang Shan Mountains. The coal bearing strata strike in the north-south direction, and dip to the east. The dip angles range from 8-30 degrees, with an average of 20 degrees. The basic structure of this coal mine is a monocline. The structural lineaments within the coal mine are mostly oriented in a northeast direction.

The folds within the coal mine are primarily wide and gentle folds oriented to the northeast. Folds with a northwest direction are relatively few and small. Synclines and anticlines appear alternately. The shape of the synclines is usually well preserved. In contrast, the anticlines are not well preserved due to tensile fracturing and the formation of grabens. Most of the faults within the coal mine are normal faults developed at the axes of the anticlines. These normal faults usually become natural boundaries of individual coal mines. South to north, several of the major folds are: the Changchun Syncline, the No. 5 Mine Syncline, the No. 2 Mine South Limb Syncline, and the No. 1 Mine South Limb Syncline.

As discussed previously, the mine area is heavily faulted due to recent tectonic movements (Exhibit 2-3). The following section discusses some of the major faults affecting the mines in the Hebi region.

$F_3$ Fault: This fault separates the shallow part of the south limb of the No. 2 Mine and the north limb of the No. 3 Mine. The strike direction is N30-55E. It dips to the northwest. The $F_3$ Fault is actually a series of faults with a total throw of about 500 m.

$F_{100}$ Fault: This fault is the boundary fault along the deep part of the south limb of the No. 2 Mine. The strike direction is N30-50E, dipping to the southeast. The throw is about 350-400 m across the fault.

The Jiagia Graben is located between the $F_3$ and the $F_{100}$ Faults. It separates the coal mine into two discontinuous blocks.

There are many smaller faults in the mine area with throws near 100 m. These faults, from south to north, include the $F_{100}$ Fault at the central part of the Lengquan Mine area, the $F_{49}$ Fault which separates the Lengquan Mine and the south limb of the No. 8 Mine, the $F_{100}$ Fault at the deep part of the No. 8 Mine, the $F_{46}$ Fault at the north limb of the No. 6 Mine, the $F_{16}$ Fault that separates the north limb of No. 2 Mine and the deep part of the No. 4 Mine, the $Red_5$ Fault inside the No. 4 Mine, the $F_{155}$ and $F_{159}$ Faults at the north of the coal mine. The $F_{159}$ Fault is the north boundary of this coal mine. All these faults have controlling effects on dividing the coal mine and methods of excavation and greatly impact the design and performance of the degasification program.

### 2.3.4 Igneous Rocks

The igneous rocks in this area can be divided into the Yenshan intrusive rocks and the Hsishan extrusive rocks. The Yenshan intrusive rocks are mostly diorite. Most of them outcrop at the north and south ends of the mountain area along the west side of the coal mine. These intrusive rocks have little or no effect on the coal. The Hsishan extrusive rocks include the picritic porphyrite, which outcrop at the Shunyu village near the No. 8 Mine, and the basalt outcrop at the Chienyin, Lulou, Yanxiaoton, and Tanaoshan, near the south of the coal mine. These extrusives can have a significant influence on the mineability of the coal.

### 2.3.5 Coal Seam Development and Coal Quality in Mine No.6

The Mine No. 6 concession is altered by several, generally large displacement northeast trending normal faults (in excess of 20 m), and frequent similar trending smaller normal faults, which along with high stress conditions, makes mining difficult and prone to coal gas outbursts.

The mining seam pitches between 8 and 30 degrees with some localized rolls where the pitch can be as high as 40 to 50 degrees. Generally the pitch of the seam is around 20 degrees. Mine No. 6 developments, including longwall panels, are designed as geologic structures are encountered during mining.

**No. $2_1$ Coal Seam.** The No. $2_1$ coal seam is found at the base of the Permian Shanxi formation. It is the main mined coal seam in the Hebi area. The thickness ranges from 3.45 to 17.5 m, although generally ranging from 7.2 to 9.2 m. The average thickness is 8.2 m. This coal seam is laterally continuous and extensive. Under this coal seam, there is a layer of 0.3 m thick mudstone. Under the mudstone, there is a thin, 0.5-0.9 m, unmineable coal seam. This seam is overlain by black and sandy mudstones, and medium grain sandstones, which break readily when under-mined.

The No. $2_1$ coal seam is black, with a vitreous to adamantine luster. The seam has a calorific value ranging from 6,430-7,895 cal/g, averaging 7,200 cal/g. Vitrinite reflectance values ($R_0$) of up to 1.6 have been reported and the coal ranks as medium to low volatile bituminous. The coal is 81% vitrinite and semi-vitrinite. It is semi-bright with banded structure. The average value of the organic matter content is 90%.

Moisture content ranges from 0.30-1.72%, averaging between 0.84-0.9%. The ash content ranges from 8.59-24.5%, averaging between 15-16.5%. The volatile matter ranges from 14.01-18.7%, averaging 17%. The sulfur content ranges from 0.22-1.77%, averaging between 0.31-0.36%. The density of the coal is approximately 1.48 $m^3$/t and the porosity of the coal is approximately 6.5 percent (ref 4).

The No. $2_1$ coal is medium ash, very low sulfur, low phosphorous bituminous coal. In some areas, where it has been affected by igneous intrusions, the No. $2_1$ coal is anthracitic, such as in the Longkong Mine located in the northern part of the mine area.

At Mine No. 6, Seam $2_1$ is generally consistent in hardness, and not well cleated based on visual inspection. The hardness is about 3 on Moh's scale and the coal breaks easily into blocks and powder.

**Gas content.** In-situ gas contents in the Hebi coal field are very high and range from 20 to 32 $m^3$/ton in virgin conditions, depending on depth. The average gas content at Mine No. 6 is reported to be 23 $m^3$/t (ref 3), while residual gas contents of the longwall panels are approximately 15 $m^3$/t. Gas composition analyses indicate that the gas adsorbed by Seam $2_1$ at Mine No.6 is between 86 to 88 percent methane, with the balance $CO_2$ (1.5%), some $O_2$ (3.6 – 4.4%), and up to 9.1 % $N_2$. The presence of nitrogen and oxygen in the gas sample suggests contamination with air and thus methane concentrations are likely higher (on the order of 95+%) (ref 4).

**No. $1_1^1$ Coal Seam and No. $1_1^2$ Coal Seam.** These two coal seams are located at the base of the Taiyuan group, approximately 100-130 m below the No. $2_1$ coal layer. The average thickness of the No. $1_1^1$ coal is 3 m while the average thickness of the No. $1_1^2$ coal is 0.8 m. Both of the seams are thinner in the southern part of the mine and thicker in the north (near the No. 4 and No. 9 Mines) and the total thickness of the 2 seams ranges from approximately 2.3 to 3.5 m. The inter-burden between the seams is comprised of black and sandy mudstones and sandstones. The mudstones form an impermeable layer preventing methane migration prior to mining, but gas emissions from charged sandstones and the lower coals occurs subsequent to longwall mining (when the adjacent strata is relaxed). The two No.1 coal layers can be mined within most of the coal mine area.

### 2.3.6 Roof and Floor Conditions

The immediate top of the No. $2_1$ coal consists of sandy mudstone or mudstone which collapses easily after mining. These mudstones are usually dense. The thickness can be up to 19.71 m, averaging 5.69 m. In the southern part of the coal area (No. 8 Mine and Lengquan Mine), these mudstones are thinner or even disappear due to erosion. Above the immediate top is a medium grain arkose quartzite (the Dachan Sandstone) that has a calcareous and argillaceous cement. The thickness is about 10 m. Immediately below the No. $2_1$ coal is another mudstone or sandy mudstone. The thickness is 0.5-16.3 m, averaging 3.1 m. Under this floor rock are fine to medium grain arkosic quartzites, the Beiyigo Sandstone. The thickness is 0.55-12.18 m, averaging 3.73 m. Most of the access tunnels for methane drainage boreholes are developed in this sandstone. Underlying this sandstone are the mudstone and sandy mudstone in the Taiyuan group. The composition of the roof and floor rocks have a major impact on the ability to drill long, directional degasification boreholes (discussed later in Section 4).

### 2.3.7 Gas Content and Gas Resources

The Hebi and Xinggong mine areas are known to be quite gassy. Based on borehole data, the gas content of the No. $2_1$ coal layer, shallower than 800 m in depth, is 13.76 cubic meters per ton. Below 800 m, there are no actual measurements. However, the gas content for coal seams deeper than 800 m can be estimated to be over 20 cubic meters per ton based on depth versus gas content relationships. For this study, a value of 22 cubic meters per ton is used to estimate the gas content. The *in-situ* composition of the gas is: 86 - 97% $CH_4$; 0.26 - 1.52% $CO_2$; 0.32 - 3.57% $O_2$; and 0.03 - 10.8% $N_2$.

The total CBM/CMM resources of the region are estimated to be 172 billion $m^3$ (6 Tcf). In the active Hebi mining area, the methane resources are estimated to be 21 billion $m^3$ (735 Bcf), while the gas resources of the deeper, unmined areas are estimated to be more than 60 billion $m^3$ (2.1 Tcf). The estimated gas resources of the Xinggong mining area are 91.1 billion $m^3$ (3.2 Tcf).

# SECTION 3

# Market Assessment for Produced Methane

# SECTION 3 CONTENTS

# SECTION 3 EXHIBITS

## 3.1 China's Energy Use

China is one of the fastest growing energy users in the world and in July 2010, overtook the United States (U.S.) to become the world's largest primary energy[1] consumer (IEA, 2010). On a fuel basis, China ranks as one of the top ten national consumers in every commercially traded fuel category (Exhibit 3-1).

| Fuel | Rank | Mtoe |
|---|---|---|
| Coal | 1 | 1,714 |
| Hydro Electric | 1 | 163 |
| Oil | 2 | 429 |
| Natural Gas | 4 | 98 |
| Nuclear Energy | 9 | 17 |
| Renewables | | 12 |
| **Total** | **2** | **2,433** |

**Exhibit 3-1: China Primary Energy Consumption by Fuel, 2010**
Source: BP, 2011

Until the early 1990s, China produced more energy than it consumed (Exhibit 3-2), but from 1995 onwards, as the economy expanded, China ran an increasing negative energy balance, consuming more energy than is produced domestically. Subsequently, the gap between domestic production of energy and consumption has grown from a 1% deficit in 1991 to a 13% deficit in 2007 (CESY, 2008).

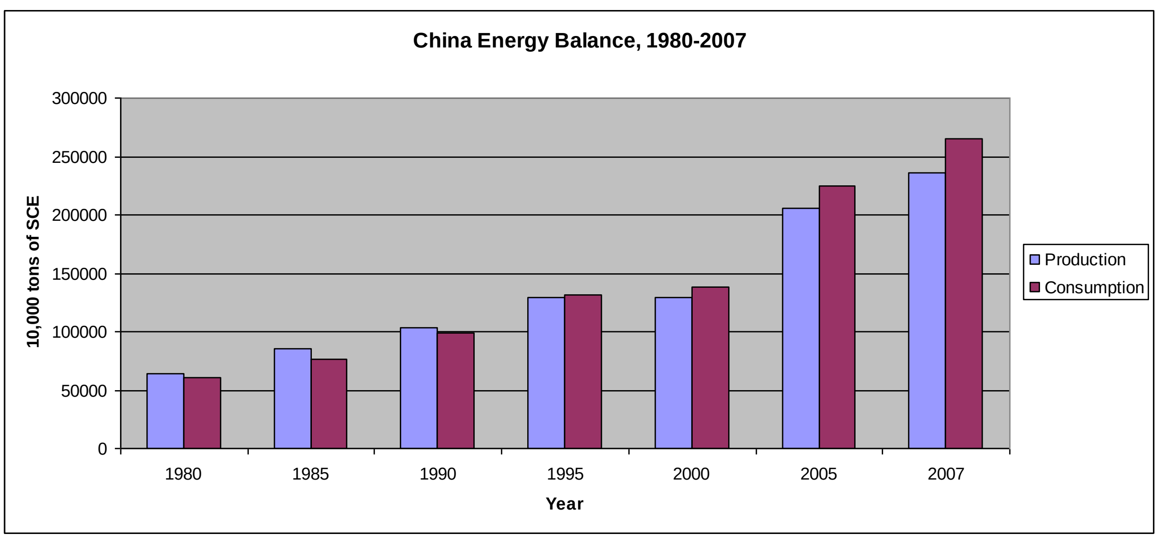


**Exhibit 3-2: China Energy Balance. 1980-2007**
Source: CESY, 2008

[1] Primary energy comprises commercially traded fuels only. Excluded, therefore, are fuels such as wood, peat and animal waste which, though important in many countries, are unreliably documented in terms of consumption statistics. Also excluded are wind, geothermal and solar power generation.

Between 1995 and 2007, energy production grew at an average annual rate of 7%, with the growth rate reaching 12% in the economic boom years of 2000 to 2007. However, annual energy consumption rates for the same date ranges averaged 9% and 13% respectively. While imports of coal, petroleum and liquid natural gas (LNG) have largely offset this gap in energy balance, the energy deficit has spurred the Chinese government to enact policies aimed at stimulating the production and use of China's own natural gas resources.

Total Chinese energy production grew by 82% from 1995-2007, with natural gas production over the same period nearly quadrupling. Coal production showed the largest increase in absolute terms, representing 78% of the increase in energy production. At the same time, total energy consumption doubled and natural gas consumption nearly quadrupled. As with production, coal consumption made up the largest increase in absolute terms, accounting for 65% of the increase in energy consumption from 1995-2007.

Coal supplies the majority of China's energy needs. Exhibit 3-3 shows that 70% of China's 2011 primary energy consumption was from coal, in contrast to worldwide energy consumption from coal of only 29% (BP, 2012).

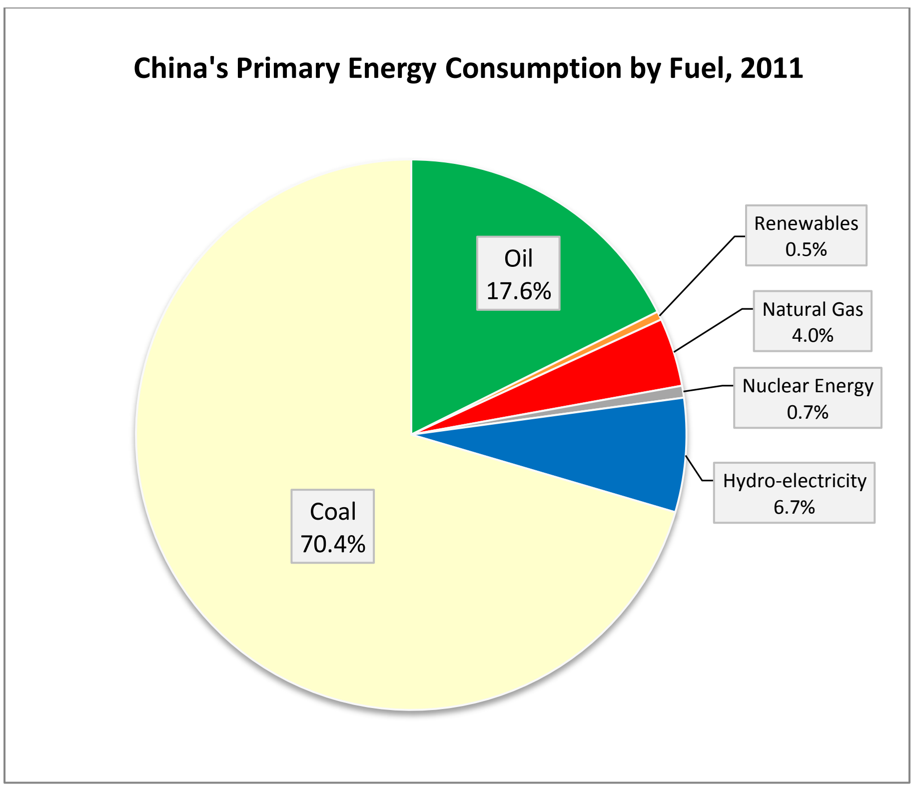


**Exhibit 3-3: China Primary Energy Consumption by Fuel, 2011**
Source: BP 2012

The industrial sector has been the primary driver of China's energy consumption, and cheap energy from coal is one of the main factors allowing China to become the world's de facto producer of energy intensive goods. In 2007, the production and supply of electric power and heat power consumed 51% of energy from coal, while the manufacturing sector consumed 36%. Some analysts feel that China is on the cusp of a consumer driven demand for energy – oil to fuel increased automobile ownership, and natural gas access and electricity access to power modern conveniences such as air conditioning and other large household appliances.

China is the world's largest coal producer, and emits more coal mine methane (CMM) than any other country. As a result of its continued reliance on coal, and subsequent increases in annual coal production, the trend of increasing CMM emissions from Chinese mines is anticipated to continue as shown in Exhibit 3-4.

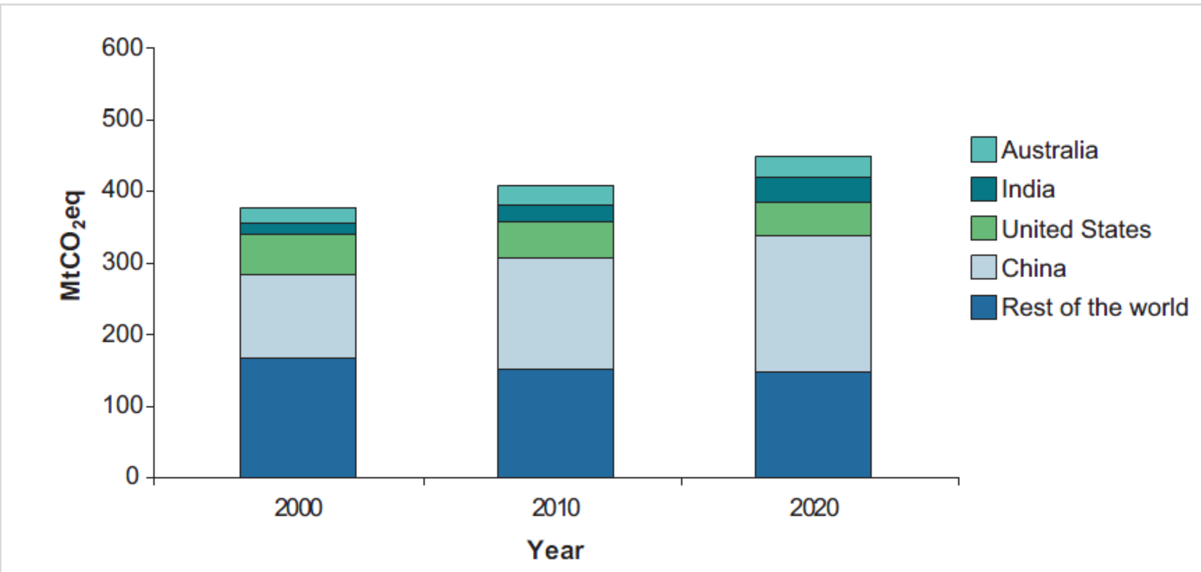


**Exhibit 3-4: $CH_4$ Emissions from Coal Mining, by Country: 2000-2020**
Source: USEPA, 2006

The majority of the CMM emitted from China's coal mines is vented to the atmosphere. Considering China's growing energy demands, this vented CMM represents a large, untapped energy resource. Before China can take advantage of this missed opportunity and increase the implementation of underground drainage to capture CMM, it must first overcome limits imposed by basic technology use and low drainage efficiencies. Fortunately, the market signals for projects such as the proposed CMM project at Hebi Mine No. 6 are becoming increasingly positive, as state and local governments see the benefits of improved mine safety, resource conservation, environmental protection, and energy security.

This market assessment identifies the different potential end-use markets for CMM produced at Mine No.6 and reviews those markets on a national, regional and local scale, with the aim to determine which markets can economically absorb the output of the proposed project. The different CMM utilization technologies are evaluated in detail in Section 5 to determine the most economically feasible use of CMM from Hebi Mine No.6.

## 3.2 Consumer base in the Hebi area

The city of Hebi is located approximately 500 kilometers (310 miles) to the south-west of Beijing in the north-central province of Henan (Exhibit 3-5). Once little more than a local market town, Hebi expanded rapidly under China's First Five-Year Plan (1953-57), when a branch line from the main Beijing to Guangzhou rail line was built to exploit the abundant coal reserves (proven reserves of over 1.6 billion tons) of the area (EBO, 2009).

Hebi is now a medium-sized industrial city and a transportation hub for northern Henan Province. With the development of a new industrial and technology area, spurred by the availability of nearby industrial mineral resources, the city's population has increased rapidly to over 1.4 million, while its 2007 GDP growth was 18.2%. (HESDR, 2007)

Hebi's mix of light and heavy industries include agricultural products processing; coal mining and dressing; raw chemicals and chemical products; electronics and machine manufacturing; metallurgy; electricity and heat production and supply; and rubber products manufacturing. Proven dolomite reserves in the area are approximately 1 billion tons and source a local, energy intensive magnesium production industry. China now produces more than 60% of the world's magnesium.

Henan Province is China's most populous province, with an estimated 2007 population of 98.7 million (HSY, 2008). The province leads the country in the production of grain and oil-bearing crops and is a big producer of cotton, meat, poultry and eggs, all of which lead to Henan Province being an important food-processing base. The thriving agricultural sector means that 66% of the population resides in rural areas. The province also has extensive mineral resources, including large reserves of bituminous, anthracite and coking coal, along with deposits of iron ore, bauxite, mica, lead, molybdenum, gold and silver. These natural resources have provided the base for the growth of large-scale industrial development led by engineering, nonferrous metallurgical, and textile industries, and Henan Province is a national leader in lead, aluminum, and glass production. Zhengzhou, the provincial capital, lies in the heart of the cotton-growing area and is one of the main focal points of China's textile industry.

Anyang, with a total population of 5.2 million, lies 25 miles to the north-west of Hebi. It has been a regional agriculture and trade center for centuries and is located on the main north-south rail line from Beijing to Guangzhou. Large-scale energy users in the city include established textile mills and food-processing plants, joined in recent years by heavy manufacturing and high-tech industries.

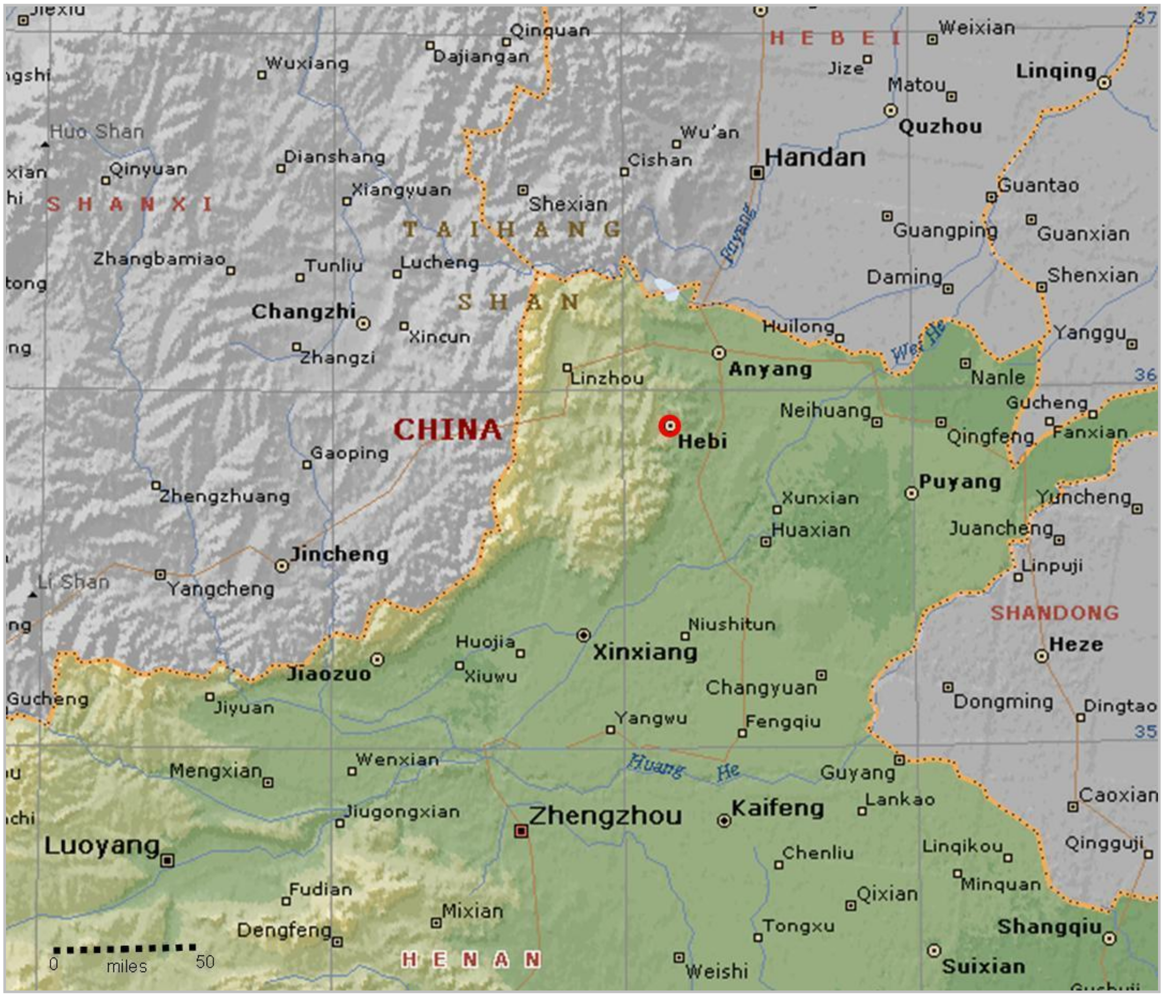


**Exhibit 3-5: Northern Henan Province**
(Source: Microsoft Encarta Maps)

Xinxiang is located 37 miles to the south-west of Hebi and is the chief city of northern Henan. Situated at the junction of major east-west and north-south rail lines, Xinxiang is also linked by the highway network to the three large provincial cities of Zhengzhou, Kaifeng and Luoyang and via expressway to Beijing. In addition to cotton-textile production, spinning, and dyeing, its industries now include food processing and the manufacture of electronics, pharmaceuticals, machinery, automobiles and automotive parts, and chemicals. The city has grown rapidly to an urban population of 5.5 million.

## 3.3 Natural Gas Market

Coal provides sixty-nine percent of the energy consumed annually in China, with only four percent provided by natural gas. Being considerably cheaper to produce than natural gas, coal will remain the dominant power source into the future, but the Chinese government is looking increasingly to mitigate the health and environmental problems associated with pollution from coal burning (especially in cities) by actively promoting the use of cleaner energy options, such as natural gas and coal mine methane. The government plans to increase the share of natural gas as part of total national energy consumption to ten percent by 2020.

### 3.3.1 Supply / Production

China's main natural gas producing basins are the Changqing Basin in the southwestern province of Sichuan, the Ordos Basin in north-central China, and the Tarim and Jungaar Basins in the Xinjiang Uyghur Autonomous Region in NW China. Other significant gas producing basins include the Qaidam Basin in Qinghai Province, the Qingshen gas field in Heilonjiang province in NE China, and offshore fields in the Bohai Basin and in the Panyu complex of the South China Sea.

The Xinjiang Uyghur Autonomous Region is currently China's largest gas producing region, with output of 24 billion $m^3$ (850 Bcf) in 2008 (EIA, 2009). The region includes the Tarim Basin, which holds at least half of China's current proven reserves (1 $Tm^3$ - 35.5 Tcf), with only 12% of the basin being explored. One of the largest recent finds is the Puguang field in Sichuan Province, with an estimated 501 billion $m^3$ (17.7 Tcf) of proven natural gas reserves. The Puguang field came online in 2008, at a rate of approximately 3.7 billion $m^3$ (130 Bcf/y), with the field operator (Sinopec) planning to double production by 2010.

### 3.3.2 Gas Pipelines

Government policies and incentives have gradually led to many Chinese cities installing natural gas distribution systems to serve domestic, commercial and industrial customers. The increased demand for gas, especially in the populous, energy intensive eastern and coastal regions of China, has spurred the construction of new gas pipelines to distribute gas from the major gas producing basins in the west and north of China. Over the past decade, China has expanded its gas distribution capabilities dramatically, but at the end of 2008 still only had 16,150 miles of natural gas pipelines, compared to 305,954 miles in the U.S.(EIA, 2009).

The most significant pipeline project to date is the construction of the West to East pipeline (Exhibit 3-6). Completed in 2004, the 4,000 km (2,500 miles) long pipeline has an annual capacity of 12 Bcm/y (424 Bcf/y), although the operator, PetroChina, has plans to increase the capacity to 17 Bcm/y (600 Bcf/y). The main pipeline terminates in Shanghai, with numerous regional spurs branching off along its length, greatly improving the interconnectivity of China's currently fragmented natural gas pipeline network. One of these spurs supplies gas to northern Henan province, including the cities of Xinxiang, Anyang and Hebi.

China National Petroleum Company (CNPC) is building a 6,400 kms (4,000 miles) long , 2nd West to East pipeline, designed to transport 31 Bcm/y (1.1 Tcf/y) of additional production from the Tarim Basin, and future imports from Central Asia, to Guangzhou in the south-eastern province of Guangdong and also to the markets of Shanghai. Feasibility studies are going ahead on the construction of a 3rd and 4th West to East pipeline.


**Exhibit 3-6: China Gas Transport Infrastructure**
(Merrill Lynch, 2007)

### 3.3.3 Natural Gas Demand

China's consumption of natural gas has increased fivefold since 2000 (Exhibit 3-7). After a slight dip in demand during the 2008-2009 world economic slowdown, gas consumption in China appears to be resuming its rapid growth. The World Bank estimates that natural gas use in China will reach 200 Bcm (7.06 Tcf) per year by 2020 (ESMAP, 2007) and the Energy Information Agency projects Chinese demand for gas to nearly triple by 2030 (EIA, 2009). China became a net gas importer in 2007 after 20 years of self-reliance and at the current production rate the World Band estimates a shortage of 80 Bcm in 2020.

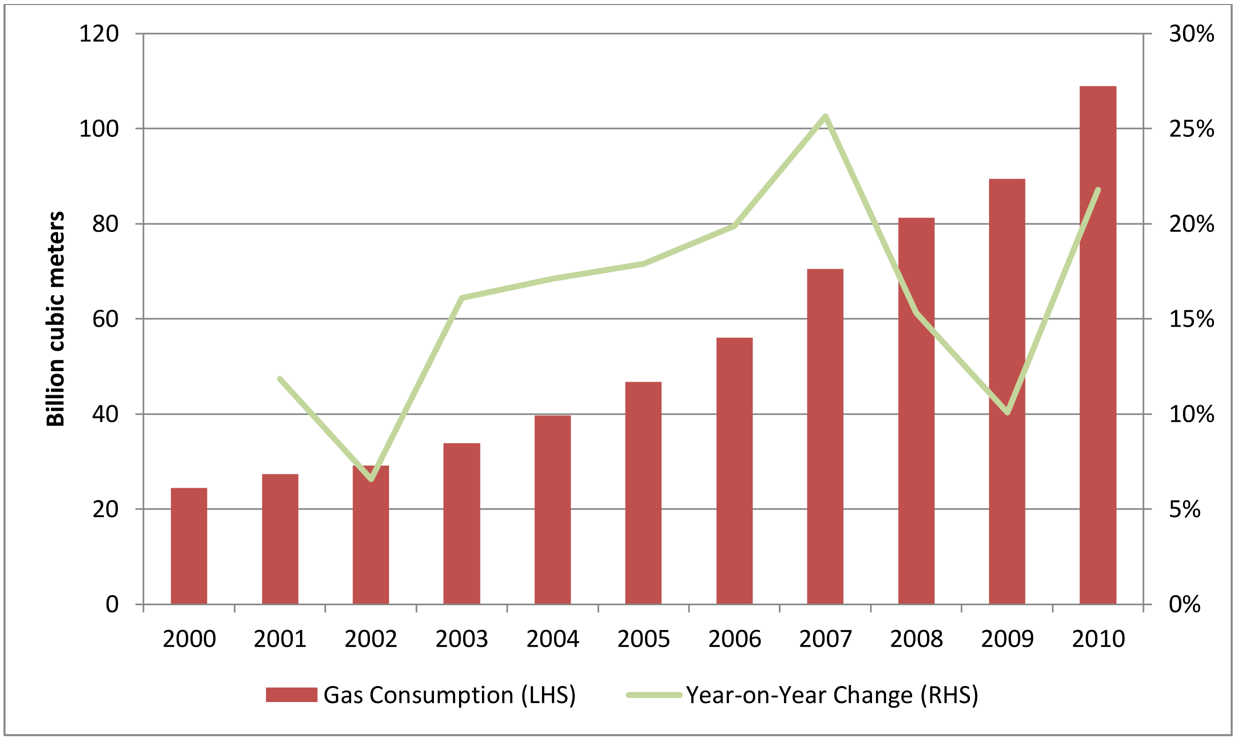


**Exhibit 3-7: China Natural Gas Consumption**
(Source Data: BP, 2011)

Gas supply-demand shortfalls are currently made up by importing LNG from Australia and other southeast Asian neighbors, while discussions are taking place with Russia, Turkmenistan and Kazakhstan to import natural gas across western Chinese borders. Increased use of domestic CMM is of great interest to reduce dependence on the more expensive gas imports.

Industrial users have dominated historic national gas consumption – in 2007 they accounted for 40% of total consumption. Recent consumption growth though, is attributed to all end-use sectors, including industrial and petrochemical, power, and residential users, with the power and residential/commercial sectors forecast to lead future gas use growth.

### 3.3.4 Pricing

Gas prices are set and controlled by the State at a national and provincial level. Average 2007 prices for gas sold to pipelines were 0.6-1.0 RMB/$m^3$ ($2.50-4.15/mcf), while gas arriving at city gates ranged in price from RMB 1.2 per $m^3$ ($5.00/mcf) close to producing areas, to RMB 2.1 per $m^3$ ($8.70/mcf) in the island province of Hainan on the east coast. Gas is distributed from city gates to end-users at different tariffs, with residential users paying the least for their gas and industrial users the most. As can be seen in Exhibit 3-8, the further the market is from the gas source, the higher the gas price is, with the nation's highest gas prices occurring in the high demand industrial and population centers on the east coast.

| | Sichuan Basin | Cities Along the West-to-East Pipeline | | | | | Shaanjing I | Zhong Wu | |
|---|---|---|---|---|---|---|---|---|---|
| City | Chengdu | Chongqing | Zhengzhou | Hefei | Nanjing | Shanghai | Beijing | Wuhan | Changsha |
| Province | Sichuan | | Henan | Anhui | Jiangsu | | | Hubei | Hunan |
| - City Gate | | | | 1.20 | 1.27 | 1.62 | 1.35 | 1.26 | 1.26 |
| - Residential | 1.43 | 1.40 | 1.60 | 2.10 | 2.20 | 2.10 | 2.05 | 2.30 | 2.36 |
| - Commercial | 2.08 | 2.05 | 2.00 | | 3.00 | | | | 2.65 |
| - Public Service | 1.72 | 1.54 | 1.75 | | | | 2.55 | | 2.55 |
| - Vehicular | 2.07 | 1.67 | 3.00 | 2.70 | | | 2.55 | | |
| All prices in RMB per cubic meter. Source: NDRC, local price bureaus, 2007 | | | | | | | | | |

**Exhibit 3-8: Natural Gas Prices in Cities near Natural Gas Fields and along Pipelines**
(Merrill Lynch, 2007)

Average national gas prices have slowly been allowed to increase over the past decade (Exhibit 3-9), as the government has had to weigh the costs and profits of natural gas producers and distributors against the socio-economic impacts of higher prices for end-users. Upgrading of end-use appliances is often needed when a city changes its fuel source to natural gas and gas prices must be low enough to make this acceptable to end-users. At the same time, prices must be high enough to ensure that critical production and pipeline projects are financially attractive.

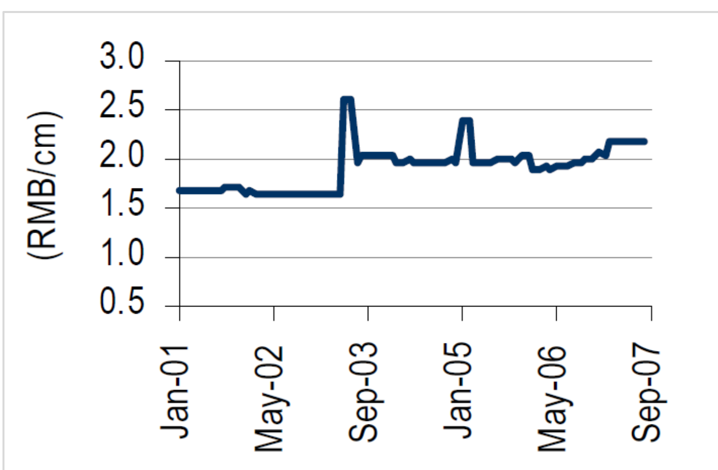


**Exhibit 3-9: Average Natural Gas Prices in Residential Areas**
(Merrill Lynch, 2007)

The Hebi region benefits from its relative proximity to gas supplies from the Ordos Basin and as such, natural gas prices are lower than on the east coast. Residential customers in Hebi pay RMB 1.7 per $m^3$ (\$7/mcf), industrial customers RMB 2.2 per $m^3$ (\$9/mcf) and commercial customers RMB 1.9 per $m^3$ (\$8/mcf). For comparison, average 2008 natural gas prices for U.S. residential customers ranged from \$10-20 per Mcf (EIA,2009), depending on proximity to market, pipeline capacities, varying transportation charges, State regulations and degree of competition.

## 3.4 Electricity Market

### 3.4.1 National Electricity Supply and Demand

From 2003 to 2007, China's electricity consumption grew steadily at annual rates of 14-15%, with a total increase of 139% from 2000 to 2007 (Exhibit 3-10). With the start of the worldwide economic downturn in mid-2008, and subsequent slow-down in output of China's industrial and manufacturing industries, national consumption of electricity increased by only 5.2% in 2008 to a total of 3.4 billion MWh, marking the slowest growth since 2000. However, the Chinese government remains focused on boosting China's domestic consumption, with a recent $586 billion economic stimulus package aimed at all sectors of the economy, and future electricity consumption, while not reaching the levels of years 2003-2007, is expected to continue increasing at steady annual rates.

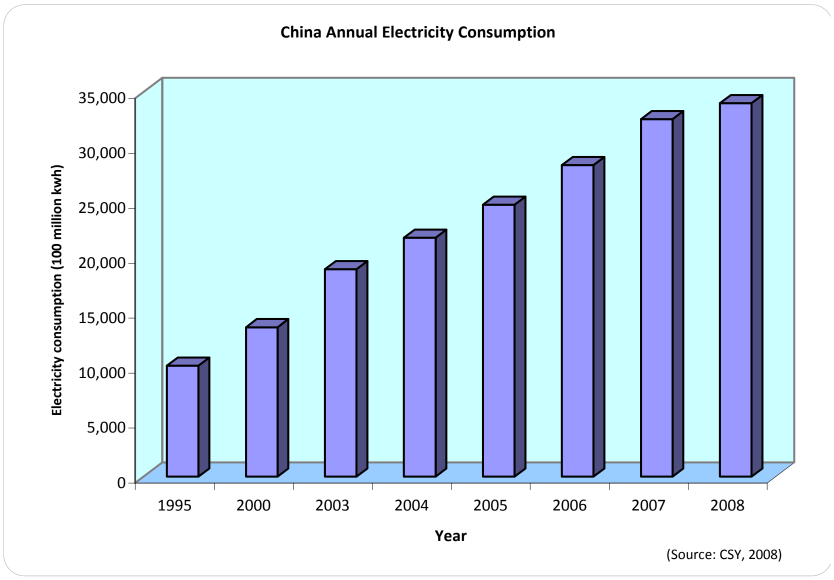


**Exhibit 3-10: China Electricity Consumption (1995-2008)**

China's total generating capacity at the end of 2008 was 792,530 MW, of which 76% was from coal-fired power plants (EnergyTribune, 2009). Construction of planned new power plants continues, even as national demand is weakening, and some analysts believe that there is a possibility of electricity generation over supply. However, the government anticipates electricity demand increasing once the Chinese economy recovers (EIA, 2009), and so continues to invest in further development of the transmission network, integration of regional networks, and bringing on planned new generating capacity. Investment in power infrastructure, including power plants and power grids, grew 1.52 percent to 576.3 billion yuan ($84 billion) in 2008.

Most of China's generated electricity is consumed by the industrial sector, with iron and steel production alone accounting for 10% of demand (Exhibit 3-11 ). The residential sector accounts for 11% of demand (Rosen and Houser, 2007) and is expected to be a growth area as urbanization continues and China's middle class grows, with resultant growth in the use of consumer electronics and electric heating and cooling. The commercial sector is also expected to increase its share of demand as China's service economy grows. The sector currently accounts for only 3% of Chinese electricity demand, as compared to 15-20% in OECD countries.

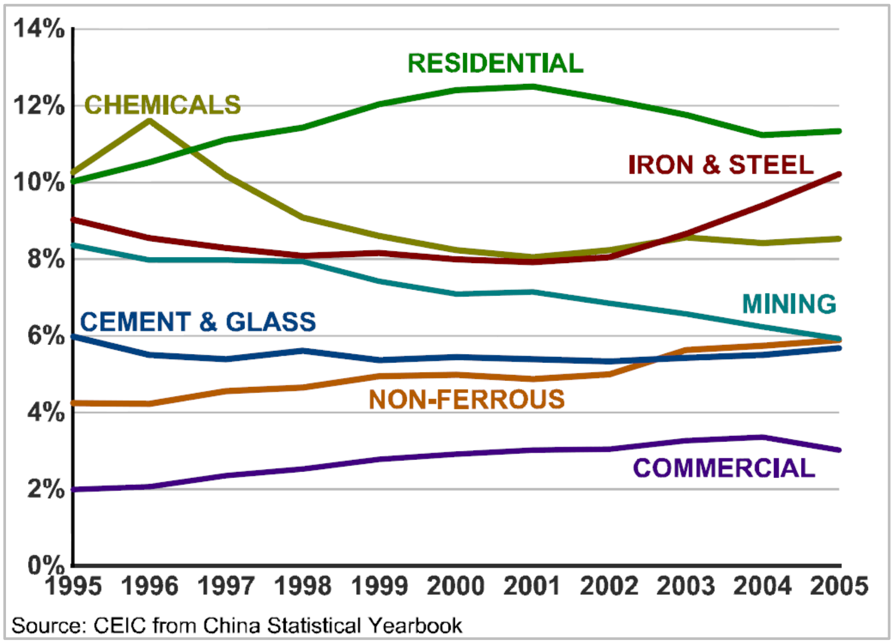


**Exhibit 3-11: Electricity Demand by Sector**
(Rosen and Houser, 2007)

### 3.4.2 Henan Province Electrical Market

Henan province is the sixth largest provincial consumer of electricity in China, with the adjoining provinces of Shandong and Hebei ranking third and fifth respectively (CSY, 2008).

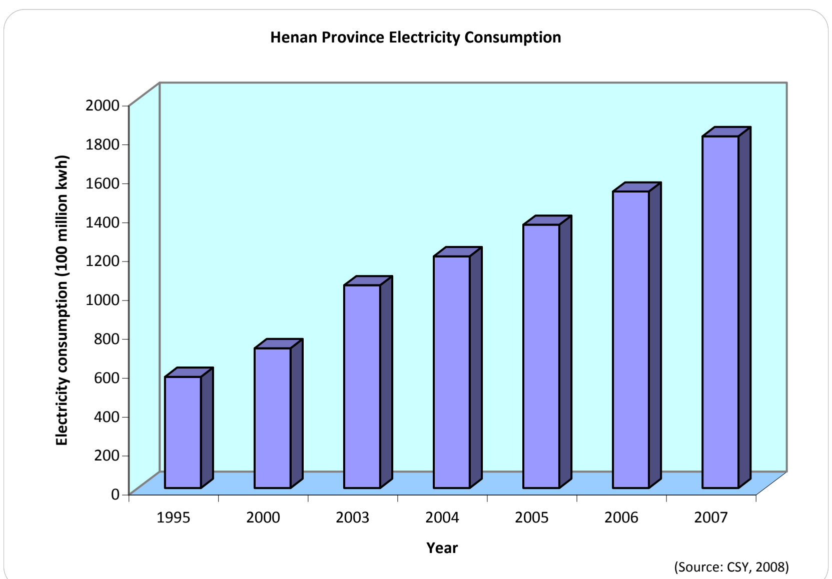


**Exhibit 3-12: Henan Province Electricity Consumption (1995-2007)**

Henan's total electricity consumption in 2007 was 180.8 Twh and its rate of growth of electricity consumption follows a similar trend to the national rates (13-19% annual increases from 2003-2007).

As well as consuming significant amounts of electricity, Henan province is also a large producer of electricity, with more than a dozen power plants constructed close to a major provincial city. (Exhibit 3-13). With an abundance of coal to fire large thermal generators and the Yellow River to power large hydroelectric power stations, Henan province is a net exporter of electricity.

| Henan Province Generation Plants | | | |
|---|---|---|---|
| **Generation Plant** | **Owner** | **Fuel** | **Flood season capacity (MW)** |
| Sanmenxia | China Datang Corp (CDC) | Hydro | 2,870 |
| Shouyangshan | CDC | Coal | 2,200 |
| Xiangtan | CDC | Coal | 1,800 |
| Lucyang | CDC | Coal | 960 |
| Anyang | CDC | Coal | 800 |
| Xinxiang | CDC | Coal | 1,250 |
| Xinxiang bacshan | CDC | Coal | 1,200 |
| Yaomeng | China Power Investment Corp (CPIC) | Coal | 2,400 |
| Jiaozuo | CPIC | Coal | 1,200 |
| Zhengzhou | CPIC | Coal | 1,000 |
| Qinbei | China Huaneng Group | Coal | 1,200 |
| Hebi | Henan Investment Group | Coal | 2,200 |
| Yahekou | HIG | Coal | 1,900 |
| Baoquan | State Grid Corporation of China | Hydro (pumped storage) | 1,200 |
| Xiaolangdi | Yellow River Water & Hydropower Development Co. | Hydro | 1,800 |

**Exhibit 3-13: Henan Province Generation Plants**
(Pittman and Zhang, 2008)

### 3.4.3 Hebi Area Electricity Market

Hebi City, with a population of over 1 million and home to a wide range of industrial and manufacturing companies, purchased 2.5 billion kWh of electricity in 2008 from the national grid. Hebi also receives electricity from a 2,200 MW thermal power plant located in the city. Large electricity consumers include magnesium producers and cement manufacturers, such as the Tongli Cement Company, which used 170 million kWh in 2007. The region's extensive dolerite resources have led to Hebi becoming a center of magnesium production, an electricity intensive industry, along with the associated manufacture of magnesium by-products.

Hebi City has grown rapidly in the last decade and while year on year growth rates have declined, the region's extensive mineral resources continue to attract heavy and light industries and the workers needed to staff them. This in turn drives the expansion of the commercial sector. As such, electricity demand in the Hebi area is expected to increase in line with national projections, at rates between 5 to 10 percent per year.

### 3.4.4 Electricity Grid

China has long struggled with the problem of most of its power generation facilities, both coal fired and hydroelectric, being located in the north and west of the country, while greater than 75% of energy demand comes from the heavily industrialized and densely populated central and eastern regions. A lack of reliable transmission capability has led to frequent supply disruptions in the major energy consuming regions.

A state monopoly, the State Power Corporation (SPC), ran all sectors of China's national electricity system until 2002, when the government dismantled it and created several new companies to run the generation sector and the transmission and distribution sector as separate entities. Electricity and transmission assets were split between seven regional and five provincial electricity grids (Exhibit 3-14) controlled by two companies, the Southern Power Company and the State Power Grid Company. Overall regulation of the electricity sector is the responsibility of the State Electricity Regulatory Commission (SERC), also established in 2002, to oversee the newly formed generation and distribution companies.

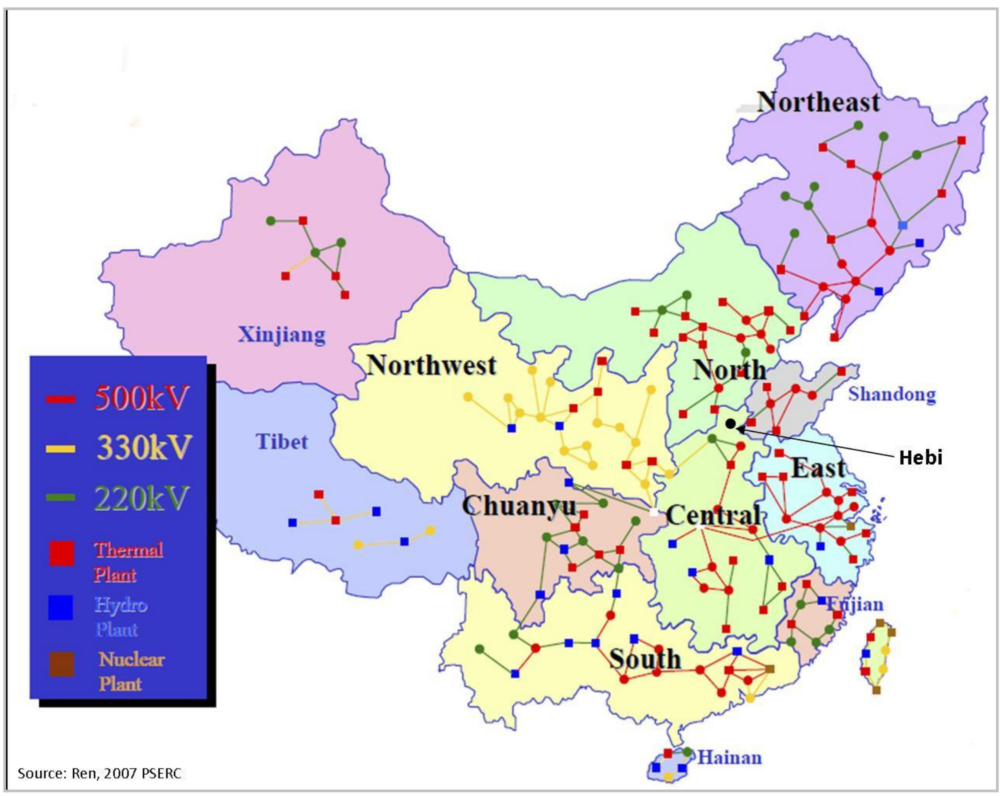


**Exhibit 3-14: Power Network in China**

While the Chinese government has allowed some market competition in the generation sector, the transmission and distribution networks continue to be heavily state-controlled, with the government providing blueprints for the development of the national electricity grid for the next ten years. Plans include the merging of the twelve separate grids into three large power grid networks by 2020 (EIA,2009), with the smaller grids linked by new, high voltage transmission lines. In January of 2009, the first such ultra-high voltage (UHV) line became operational between Shanxi Province and Hubei Province. Designed to transmit power over long distances, without the transmission losses associated with the more common 500kv lines, the 640 km long, 1,000 kv line joins the North China power grid with the Central grid for the first time. Three major west-to-east transmission corridors are also planned (North, Central and South), with the capacity of each corridor reaching 20GW by 2020, all with the aim of alleviating supply problems between western generators and eastern consumers.

The electricity distribution system in Henan province is part of the Central grid and, as shown in Exhibit 3-14, the Hebi area sits in the middle of well-established high voltage grids. Urban distribution grids in the area surrounding the mine are well developed.

### 3.4.5 Electricity Price

The NDRC has complete control over electricity prices and it determines both the price at which generating companies can sell power to the grid and what prices the grid operators can charge different categories of users. These prices are set on a province-by-province basis, in consultation with local price bureaus. The NDRC attempts to balance affordable prices for industrial and residential customers with the need for generation and grid companies to make enough profit to finance future power plants and transmission networks. Electricity rates currently favor industrial customers and can be 40% lower than other retail customers (EIA, 2009) and this is certainly the case in the Hebi area. Residential customers pay between RMB 0.52-0.56 per kWh (7-8 cents/kWh) in the region while industrial users pay RMB 0.33-0.49 per kWh (5-7 cents/kWh). Hardest hit are commercial customers who pay RMB 0.73-0.80 per kWh (11-12 cents/kWh). Grid companies buy electricity from power companies at a cost of approximately RMB 0.3-0.4 per kWh (4-6 cents/kWh).

China's electricity market is complicated by the government trying to control prices to end users, while the price of coal, the major fuel source for power generation, is subject to market forces. In times of large thermal demand, power generators have lost money as the price of coal rose and increased costs could not be passed on to consumers. In some cases, this has resulted in power stations shutting down and exacerbating supply problems. In response to such price imbalances, the NDRC is working to reform the electricity pricing structure to allow more market influence. These reforms are expected to lead to higher electricity prices for all users in the near future.

### 3.4.6 Electricity Generation Using CMM

The first major use of CMM for electricity generation was at the Appin and Tower Coal mines near Sydney, Australia. In 1996, 94 individual one MW spark-ignited reciprocating gas engines were installed in two CMM power generation plants (with total capacity of 94 MW). Since that time, China has adopted CMM power generation technology widely and used CMM for generating electricity at many of its mine sites, its most notable success being at the Sihe Mine in Shanxi province, where the world's largest CMM to power generation facility (with a capacity of 120 MW) is installed. At most mine sites, however, generation facilities are generally in the 0.5-2 MW range and electricity is generated solely for use at the mine site.

Power generation from CMM is becoming increasingly important in China. IEA (2009) report that "in 2005, 2.3 billion $m^3$ of methane was drained; 1.0 billion $m^3$ was used; and power generation capacity (including plants installed and under construction) reached 200 MW. By 2006, these figures became 3.0 billion $m^3$, 1.2 billion $m^3$, and 460 MW. According to the latest five-year plan, China will drain 5 billion $m^3$ of coal mine methane and utilize 60% of this gas by 2010." This figure may be conservative as 4.7 billion $m^3$ of CMM was drained in 2007, with more than 2 billion $m^3$ drained from Shanxi Province alone. Henan province recovered about 0.2 billion $m^3$.

### 3.4.7 Policies to Promote CMM Electricity Production

CMM has been captured and used in China as far back as 1952, when CMM from the Fushun Mine in Liaoning Province was used as the raw material for a carbon black plant. However, it was not until 1982 that the Chinese government formally recognized CMM's potential as a power source and CMM utilization was added to the national investment plans of capital construction and energy conservation (CBMC, 2004). The Fushun mine went on to build China's first demonstration CMM power plant (1,500 kW) in 1990 and added a second plant (2 x 2,000 kW) in 2002.

In 2007, in a bid to accelerate the development of power projects fueled by CMM, China's National Development and Reform Council (NDRC) issued new requirements covering the generation of electricity by CMM/CBM projects (IEA, 2009). Specifically, grid operators should give priority to CMM generated electricity and should purchase the electricity at an NDRC specified, subsidized price. The requirements also promote CMM power generation facilities larger than 500 kW per unit, by making such projects exempt from paying the connection fee normally charged to small scale coal fired plants, and exempt plant operators from market price competition, while minimizing their responsibilities to providing grid stability

In practice, electricity distribution companies do not find it profitable to use the more expensive, subsidized CMM generated power, and have tried to make up lost revenue by charging additional fees for use of the power distribution grid. This in turn makes the economics of CMM electricity generation for sale to the grid unattractive for mine operators. Provincial representatives of the NDRC appear to have little authority to enforce the nationally mandated CMM power subsidy and access policies and as a result, these policies have had limited implementation (IEA, 2009).

## 3.5 CMM Market

### 3.5.1 Policies to Promote CMM Capture and Utilization

With 36 trillion cubic meters of reserves, China holds the world's third largest reserves of coal seam methane, behind Russia and Canada. Methane-related explosions in mines are a major safety concern to China's coal industry and the NDRC is increasing efforts to expand a safety campaign addressing weaknesses in the management and treatment of coal seam gas in medium- and large-sized coal mines. The campaign aims to prevent gas explosions in mines, while increasing the extraction and use of CBM/CMM. Despite pumping 5.8 billion cubic meters (Bcm) of CBM/CMM from underground mines in 2008, China used only 1.8 Bcm (Shen and Wong, 2009), a 31% utilization rate. In an attempt to increase this rate, the government has implemented several policies designed to increase CBM/CMM use.

For example, a policy implemented in 2007, gives a financial subsidy of RMB 0.2/$m^3$ to projects that use CBM/CMM onsite (not to generate power) or market gas for residential use or as chemical feedstock. In addition, the central government is encouraging provincial and municipal level governments to give grants or offer favorable loan terms to CMM projects. There are also many policies that offer favorable tax treatment to project developers. These benefits include exemption from income tax and some import tariffs, reimbursement or exemption from value-added taxes, accelerated capital depreciation, and other policies to offset income taxes (IEA, 2009).

### 3.5.2 CMM Production

The Chinese government's push to increase safety in coal mines has led to a steady increase in the number of mines with installed methane drainage systems, with a dramatic associated increase in drained volumes of CMM, which rose from just over 2.5 Bcm per year in 2005 to over 4.7 Bcm per year in 2006 (Exhibit 3-15). The World Bank predicts continued increases in drained volumes of CMM for the near future, because of annual increases in coal production, a greater proportion of production from longwall operations and an expectation of increasing gas drainage, capacities and performance (ESMAP, 2007).

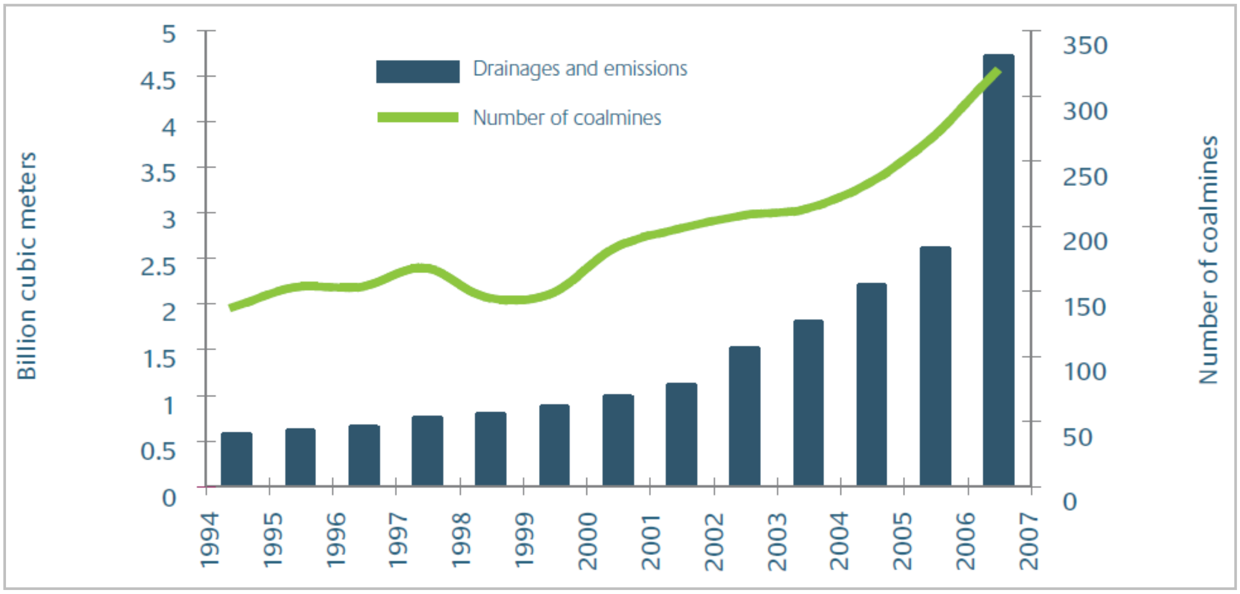


**Exhibit 3-15: Coal Mines with CMM Drainage Systems and Associated Drained Volumes**
(IEA,2009)

In most Chinese coal districts however, CMM drainage takes place with a focus on increasing coal production and the safety of miners, and not on the capture and use of methane. This results in low methane drainage efficiencies of less than 30% (as shown in Exhibit 3-16). Contributing to national low overall mine gas capture efficiency rates is the fact that many mines with multiple longwalls may not be dangerously gassy and so do not need to pre-drain methane, which instead is released to the atmosphere with ventilation air.

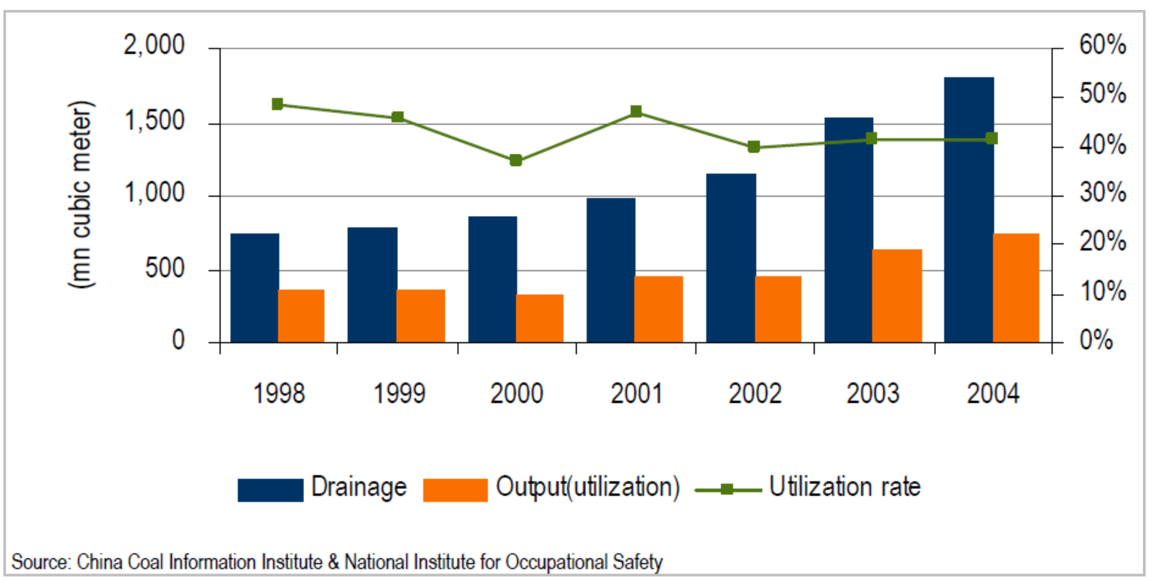


**Exhibit 3-16: CMM drainage, output and utilization rates**
(Merrill Lynch, 2007)

## 3.6 Potential Markets for CMM from Hebi Mine No.6

The quality of CMM, as measured by its methane concentration, is the main factor in determining its use. CMM is explosive when it contains 5-15% methane and so most countries set minimum concentration limits of 30% or higher, for the safe use of CMM. China mandates the minimum safe limit at 30%, but many mining groups interpret this limit as only applicable to gas for domestic uses, or consider the limit outdated and not applicable. Chinese manufacturers of electricity generator sets have developed generators that run on methane concentrations lower than 30% and many mines now use them. While innovative, the use of low quality CMM is a potential hazard and is a disincentive to improving inefficient methane drainage systems.

The variability of CMM supply is another factor affecting potential end use. CMM production is dependent on the rate of mining and the gas content of the coal mined. Gas contents will vary in different mining areas in the mine, while any suspension in mining operations (caused by machinery moves, maintenance or accidents, for example) will reduce the volumes of CMM captured at the surface. This problem can be mitigated with the use of storage tanks that can be tapped during supply disruptions, but only for a limited period.

Many mines in China are located in rural areas, far from the large population centers that serve as potential markets for captured CMM. When combined with low CMM quality (< 30% $CH_4$) and relatively low produced volumes, it is not economically feasible for most rural mines to utilize CMM off-site. In this case, CMM is typically used by the mine itself or by a relatively small number of domestic users close to the mine. Excess CMM is then released to the atmosphere. Nationwide, these obstacles to CMM use result in an average national utilization rate of less than 50% of drained CMM volumes. However, mines which produce large volumes of better quality CMM (30-50+% $CH_4$), or are located closer to large markets, have more CMM use options open to them and can, in some cases, utilize almost 100% of their drained CMM.

As can be seen from Section 3.2, Hebi Mine No.6 is located in an area of high demand for energy in all forms, which provides several possible markets for CMM produced from the mine. These markets are summarized below and the most favorable are discussed in more detail in Section 5 "Evaluation of Methane Utilization Technologies."

### 3.6.1 Firing or co-firing boilers for hot water and space heating

- The produced hot water can be used in mine offices and workers' accommodations and/or can be supplied to nearby local residents.
- Firing boilers is a common use of CMM in China, but uses only a small percentage of extracted CMM.

- Demand from domestic users varies widely daily and seasonally and CMM is often vented during the summer months when it is not needed for heating.
- Small volumes of CMM are used to provide hot water and heating at Hebi Mine No.6 but there is no demand for increased use.

### 3.6.2 Coal drying

- CMM drained from Chinese mines has been used for coal drying and this is a potential growth market as more Chinese coal is washed to meet increased coal quality standards.

### 3.6.3 Sales to pipeline

- Coal bed methane, drained from undisturbed coal seams, often has high enough methane concentrations to be injected into a sales pipeline with minimal processing. This is not the case with CMM, where even high quality CMM (50-70% methane) is significantly contaminated with ventilation air and requires extensive processing to reach pipeline quality. Nitrogen, oxygen, sulfur and excess amounts of water, carbon dioxide and any other impurities must be removed from the CMM, so that it contains a minimum of 93% methane[2], before compression into a transmission pipeline. This process requires the construction and operation of an expensive processing plant, along with a transmission pipeline to carry the processed gas to the nearest sales pipeline.
- The nearest natural gas sales pipeline to Hebi Mine No.6 is a trunkline from the West-to-East pipeline, which delivers gas to Hebi City. It is more economic to deliver gas straight to Hebi's city gate, which pays RMB 1.6 /m3, rather than via the trunkline paying only RMB 0.6-1.0 per m3.

### 3.6.4 Sales to residential users

- CMM with a methane concentration greater than thirty percent in air is piped to residential areas and used for cooking purposes in many parts of China, although end users must be tolerant of the variable supply issues which occur with CMM use.
- Coking gas is often used in Chinese cities as a cooking fuel and has a similar Btu content (heating value) to that of CMM, which allows for direct substitution of CMM for coking gas.
- Hebi City is supplied with high quality natural gas via a trunkline from the West-to-East pipeline. CMM from the mine would require extensive processing to reach the quality of the gas already used in Hebi City and an approximately 15 km long transmission pipeline would be needed to transport gas to the city gate distribution point.
- Capacity for additional gas in the city distribution system will vary depending on volumes delivered by the West-to-East pipeline.

[2] As regulated by the National Gas Quality Standard GB17820-1999

### 3.6.5 Electricity generation

- Many mines use Chinese made reciprocating engines, especially designed to be fueled by low concentration CMM, to produce electricity for the mine's use. The engines are relatively low cost, modular and can operate using varying amounts and concentrations of input gas.
- Heat exchangers on the generators can heat water for radiators or boilers
- Power generation from CMM is generally considered less costly and less complex than sales-to-pipeline projects.
- Hebi Mine No.6 has installed five Shengli generator sets on site and uses about 65% of the current daily CMM production to generate approximately 50% of the mine's power requirement. The proposed methane drainage improvements are predicted to capture enough CMM to power extra generators and increase generation capability to 93% of the mine's electricity requirements. Using CMM for power generation for the mine's use seems the most obvious market for Hebi Mine No. 6's produced CMM.
- National policies encourage CMM generated electricity sales to the grid, although policies are not widely enforced and local electric grid operators have ignored them in the past.

### 3.6.6 Mine shaft heating and cooling

- Mine shaft heating is a mandatory process in northern China to prevent ice hazards and protect miners during harsh winters. In warmer latitudes, gas powered air-conditioning units can be used to cool mine shafts.
- January temperatures at Hebi Mine No.6 average -2°C and heat produced during power generation is used to heat the mine.

### 3.6.7 Feedstock for chemical processes

- CMM is a potential source of methane for use in the production of fertilizers and chemicals such as ammonia, methanol and carbon black.
- As is the case with selling CMM into a pipeline, the feed CMM needs to be processed to remove nitrogen, oxygen, sulfur and other impurities to increase its methane concentration before being used in the fertilizer and chemical manufacture.
- Hebi Mine No.6 does not produce CMM of high enough quality or in enough volume to be an economic source of methane for chemical processing.

### 3.6.8 Compressed Natural Gas (CNG)

- CMM of sufficient quality can be compressed to reduce its volume for transportation to available markets.
- CNG use is a growing market in China and it is popular as a vehicle fuel, especially in taxis and with bus fleets, because CNG is up to 40% cheaper than gasoline (on a comparative scale.)

- Most production is currently centered near producing gas basins or major pipelines, although some projects have used CBM as a feedstock. Jincheng City in Shaanxi Province, 100 km from Hebi, is a major source of CBM for a CNG processing plant which distributes CNG to central Henan Province
- Again, to achieve the high methane concentrations required for CNG production, the CMM from Hebi Mine No.6 would have to be extensively processed, making it uncompetitive as a CNG source.

### 3.6.9 Liquefied Natural Gas (LNG)

- LNG is used to fill the gap between China's ever increasing demand for natural gas and its lagging domestic supply. China began importing LNG in 2006 and import volumes have grown rapidly. Total imports are reported to have more than doubled between 2008-2009, with average imports of 12 MMcm/d (420 MMcf/d) in 2008 and 37 MMcm/d (1.3 Bcf/d) in 2009.
- Most LNG is imported from neighboring Asian countries such as Indonesia, Malaysia and Australia, with additional volumes coming from the Middle East (Qatar)
- Imports arrive at terminals on the east coast and the LNG is processed in large regasification plants. Two are currently in operation, with a further four in the construction stage and three more have been approved to be built
- Over 60% of the imported LNG is used in new gas fired power stations, while the rest is distributed as town gas for residential and industrial end users.
- China also has almost a dozen domestic LNG plants in operation or under construction and leads the world in small scale LNG production. When the plants are all on-stream, they will produce between 6-7 MMcm/d, equivalent to 15-20% of current import volumes.
- The smallest domestic LNG project uses more than 115 Mcm/d of input gas, which is four times as much gas as Hebi Mine No.6 is projected to drain. The production of LNG at Hebi Mine No.6 is not considered economically feasible because of the low volumes of drained methane and the high processing costs associated with cooling the gas to -260 F.

### 3.6.10 Flaring

- Methane is calculated to be 21 times more potent as a greenhouse gas (GHG) than carbon-dioxide (IPCC, 2001) and so burning CMM in a flare, which destroys the methane but does produce some carbon-dioxide, is considered a good option for GHG reduction (as opposed to just venting the CMM to the atmosphere).
- Proposals to flare excess CMM have been rejected by the NDRC, who consider flaring a waste of energy. This is true where there are economic alternatives to flaring, but at many mines this is not the case.

## 3.7 Summary

Most major studies of China's energy use predict steady increases in the use of all energy sources over the next twenty years. As the cheapest fuel, coal will still provide the bulk of energy requirements, but China's national government is actively promoting the use of natural gas in an effort to reduce pollution from the country's heavy coal use. They anticipate boosting the share of natural gas as part of the country's total energy consumption, from the current 4% to 10% by 2020.

Hebi Mine No.6 is situated within a major industrial area with a large residential population. As such, there is a large demand for both electrical power and natural gas in the area and this demand is predicted to grow steadily at rates of 5-10% a year. Hebi City receives natural gas via a trunkline from the West-to-East pipeline and has a well-developed gas distribution system. The city is supplied with electricity from a local thermal plant and major transmission lines from the regional grid. Hebi City is a transportation hub with good rail and road access to Beijing and the region's major cities.

Hebi Mine No.6 currently generates 50% of its electricity needs and purchases the remainder from the local grid. ARI believes the most attractive market for the CMM volumes produced by upgrading the mine's methane drainage system and drilling techniques is electricity generation for the mine's use. The produced electricity will supply approximately 93% of Hebi Mine No. 6's power needs, which leaves capacity in the system to utilize any increases in CMM production beyond those predicted in this study.

Generating electricity on site is attractive, because the input CMM gas stream can be utilized as is, with minimal processing and transportation. Additional generating sets can be installed relatively cheaply and infrastructure for the power plant and distribution system is already in place. The other major markets reviewed in this section (sales to pipeline; sales to residential users; CNG and LNG) all require significant processing of the CMM gas stream, to increase its methane concentration and remove contaminants. A specialized processing plant would have to be installed, with subsequent training of mine personnel on use and maintenance. CNG and LNG production would require construction of production facilities, while gas sales would require the building of pipelines to suitable sales points. The low volumes of CMM produced at the mine are not deemed sufficient to provide the economies of scale needed to make the aforementioned end uses of CMM more economically attractive than electricity generation.

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# SECTION 4

# Evaluation of Degasification Technologies and Reservoir Simulation

# SECTION 4 CONTENTS

# SECTION 4 EXHIBITS

## 4.1 Introduction

The first part of Section 4 reviews different degasification techniques employed in the coal mining industry, followed by a detailed examination of current degasification techniques at the Hebi No. 6 mine. Recommendations based on numerical simulations are provided that will help the mine increase its drainage efficiency, both in terms of quality and quantity of gas produced.

In the second part of Section 4, current mine degasification practices were modeled using ARI's Comet 3 reservoir simulator. A baseline case was generated and used to model and evaluate alternative degasification methods. Results were used to derive recommended practices. The over-all impact of the recommended practices and the costs of implementation are presented in the final sections.

## 4.2 CMM Drainage Techniques

Mine operators perform degasification functions in three ways:

- by reducing the gas content of virgin coal seams and other gas bearing strata prior to mining by drilling vertical or horizontal wells from the surface, or from within the mine workings using rotary or directional drilling techniques;
- by extracting gas from gob regions formed subsequent to mining (gob degasification);
- by extracting methane from sealed areas isolated after mining.

CMM recovered from any degasification method applied underground can be collected in a gathering pipeline and routed underground for dilution in the exhaust ventilation air or, more commonly, transported safely to the surface, for venting to the atmosphere or for use as a mid to low grade energy source.

The flow rates and gas quality can vary considerably between various degasification techniques. Pre-drainage wells, or horizontal boreholes drilled in advance of mining, generally produce high quality methane gas (90%+) at low to moderate rates. Gob gas drainage methods generally produce medium to high quality methane (50-80%), at relatively high rates initially for vertical gob wells, but both the quantity and quality of methane produced declines after several months. The important aspect of all types of methane produced from degasification systems is that it represents a valuable energy resource that can be utilized in several ways. Exhibit 4-1 depicts the different methane drainage techniques and their end-use options.

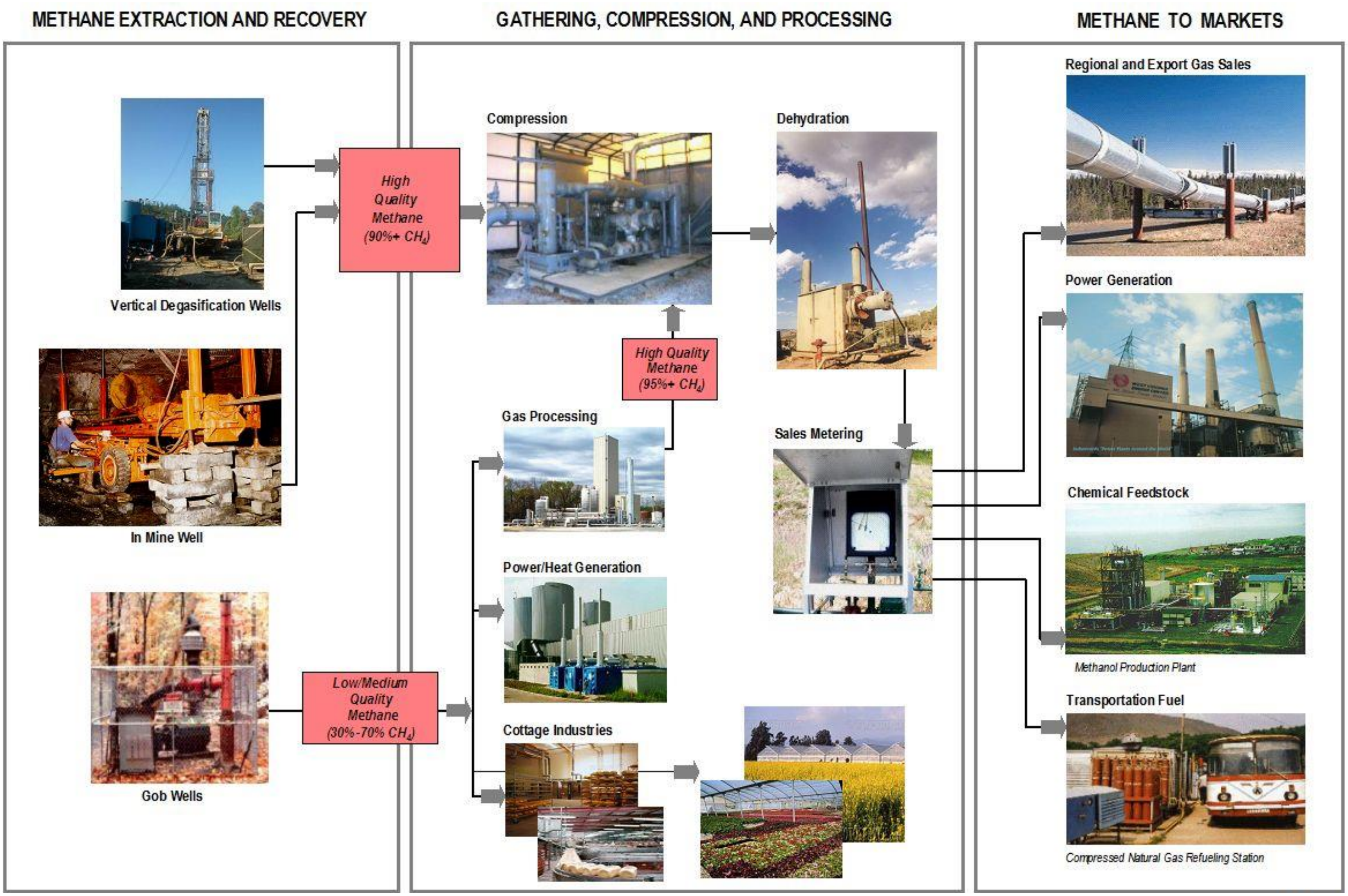


**Exhibit 4-1: Coal Degasification: Production through Utilization**

### 4.2.1 Pre-Mining Degasification

Pre-mining degasification targets regions of un-mined coal or other gas bearing strata in advance of mining activity with the objective to greatly reduce the methane content of the mining seam, or of adjacent seams, to reduce the potential for future generation of gob gas. Pre-mining degasification is practiced from within the mine (underground), using horizontal boreholes, or from the surface with vertical wells. Where reservoir characteristics are favorable (e.g. where coals have sufficient permeability and rapid diffusion rates), coal operators can drain gas from large areas. With low permeability coal and/or coals with slower diffusion rates, mine operators normally begin drainage far in advance of mining (2-10 years). Incorporated with an underground gas gathering system, underground pre-mining degasification systems can recover pipeline quality gas.

The three methods commonly used for pre-mining degasification are cross-panel boreholes, long in-seam directionally drilled boreholes, and hydraulically stimulated vertical wells drilled from the surface. The underground pre-mine degasification techniques are illustrated in Exhibit 4-3 and Exhibit 4-2.

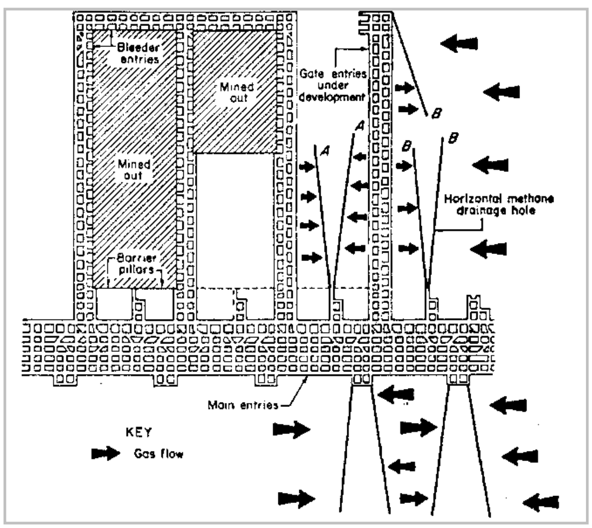

**Exhibit 4-3: Long In-Seam Boreholes drilled in Longwall Panels in advance of Gateroad development**

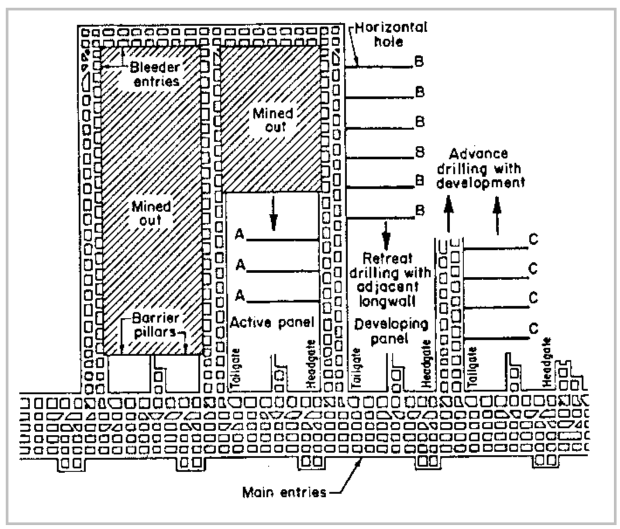

**Exhibit 4-2: In-Seam Boreholes drilled across Longwall Panels during Gateroad development**

Vertical wells drilled from the surface through multiple coal seams and stimulated by hydraulic fracturing are utilized for the recovery of CBM on a commercial scale. In some cases, mine operators implement these wells to also reduce gas contents of seams that will be mined 5 to 10 years in the future. With this technique, commercial operators work with the mines regarding well locations, particularly as mines are concerned about stability issues when mining near hydraulic fractures. Due to costs, this system of CMM drainage is not implemented without consideration of the economic value of the recovered gas over the productive life of the wells.

### 4.2.2 Gob Degasification

There are three primary methods of longwall gob degasification techniques used world-wide, and mine operators often adopt variations of these: surface drilled vertical or angled gob wells, cross-measure boreholes, and superjacent techniques (overlying galleries, or boreholes drilled from overlying galleries, and overlying or underlying horizontal gob boreholes). Exhibit 4-4 generally illustrates these practices.

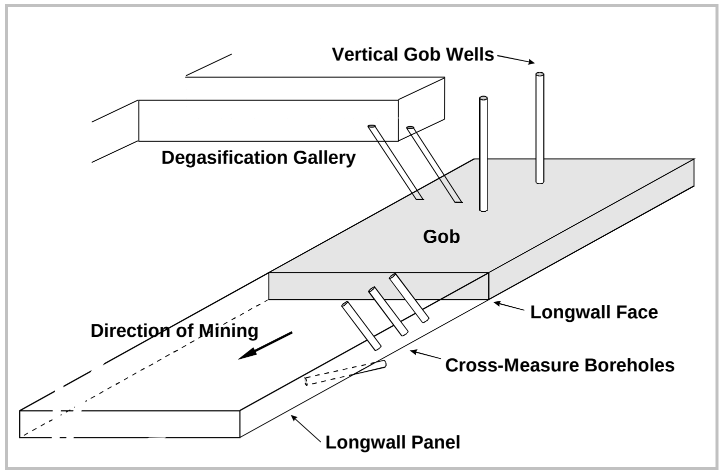


**Exhibit 4-4: General Description of Gob Gas Recovery Methods**

### 4.2.3 Surface Drilled Gob Wells

Surface drilled vertical gob wells, most predominantly used in the U.S., are drilled in advance of mining, with diameters of up to 300 mm (12 inches) and are placed vertically above the mining seam. Gob wells are typically cased and cemented to a point just above the uppermost coal seam or gas bearing strata believed capable of liberating gas resulting from the longwall mining operation, and then lined with slotted casing down to just above the mining seam (Exhibit 4-5).

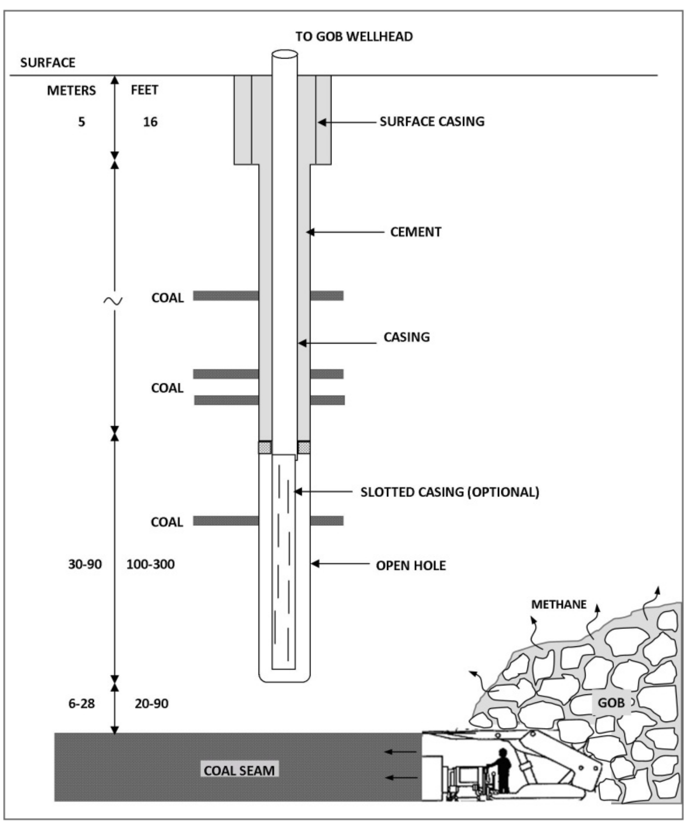


**Exhibit 4-5: Schematic of surface drilled gob well**

At some mining operations where overlying gas bearing strata of high gas content are present and where gob permeabilities are very high, operators can obtain excellent gas production rates and maintain high gas qualities with surface drilled gob wells operated under vacuum. Surface drilled gob wells are not suitable for mines developed under urban areas and where surface access and right-of-way are restricted. Surface drilled gob wells are also difficult to implement with multiple seam operations.

#### 4.2.3.1 Cross-Measure Boreholes

The cross-measure technique of longwall gob degasification is the dominant method used in Europe (east and west) and in Russia, where deep multiple coal seams are mined using the longwall method. Cross-measure boreholes are small diameter boreholes (75 to 100 mm in diameter) that are drilled at angles from gateroad entries up into overlying or down into underlying strata, in advance of the longwall face. In extremely gassy conditions, operators will place boreholes from both the headgate and tailgate entries, and surround the panel. Each cross-measure borehole collar is connected to an underground gas gathering pipeline that provides vacuum to the wellheads and routes the gas to the surface. The cross-measure borehole system is particularly applicable where deep reserves are mined at multiple levels and where surface access or topography limits surface options (surface drilled gob wells).

#### 4.2.3.2 Superjacent Techniques

Superjacent techniques, involving the use of drainage galleries developed in advance of mining in overlying or underlying strata are used at some of the deeper and gassier mining operations in Eastern Europe, Russia, and China. Small diameter, short boreholes, are drilled into overlying strata from the galleries, and/or the galleries are sealed and connected directly to a gas collection system operating under high vacuum. More recently, superjacent techniques involving in-mine directionally drilled boreholes placed over or under the mining seam in advance of longwall operations have been applied in Japan, China, Australia, Germany, and in the U.S.

#### 4.2.3.3 In-Mine Directionally Drilled Gob Boreholes

This technique applies state-of-the-art, in-mine directional drilling equipment normally used to develop long in-seam methane drainage or exploration boreholes. In-mine gob boreholes, 75 to 150 mm in diameter, are drilled into the strata overlying or underlying un-mined panels to lengths of up to 1,500 m as shown in Exhibit 4-6.

Overlying boreholes are strategically placed:

- into the lowest producing source seam (for pre-mining drainage) or below the lowest producing source seam, depending on elevation above the mining seam and the geomechanical characteristics of the gob,
- to intersect the fracture zone above the rubble zone after the gob forms,
- over the tension zones near the edges of the longwall panel,
- over the low pressure (depends on mine ventilation system) or high elevation side of the gob,
- to remain intact following undermining and produce gob gas over the entire length of the borehole.

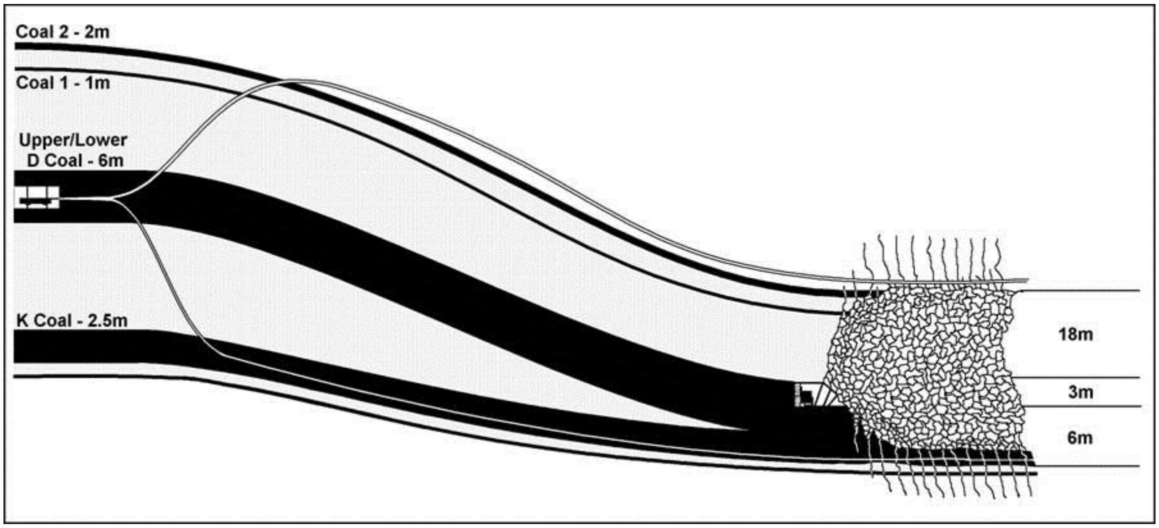


**Exhibit 4-6: In-Mine Directionally Drilled Gob Boreholes placed in an Underlying Coal Seam and above the Mining Seam.**
(Source: REI Drilling)

The advantages of this technique over the cross-measure method are:

- the boreholes can be developed in advance of mining, away from mining activity for either advancing or retreating longwall systems,
- fewer, longer boreholes can produce an effective low pressure zone over the gob, relative to numerous cross-measure boreholes,
- strategic placement may allow borehole collars to remain intact (protected from the effects of local stress redistribution) and allow boreholes to remain productive after longwall mining is completed,
- the system may be more effective and less costly to implement and easier to operate than a system of cross-measure boreholes.

Relative to a system employing drainage galleries, horizontal gob boreholes are less costly to implement, particularly if the galleries are developed specifically for degasification and mined in rock or in uneconomic coal seams.

Recent work to optimize placement, performance, and integrity of these directionally drilled overlying gob boreholes has lead to the development of larger diameter holes, the installation of perforated steel casing, and careful monitoring of wellhead vacuum as a function of mining activity.

## 4.3 Recovery of Gas from Sealed Areas

Following longwall mining, districts comprised of a group of longwall panels, or individual longwall panels alone, are typically sealed from active mine workings to minimize leakage of mine ventilation air to non-working areas, and for other mine safety reasons (spontaneous combustion, etc.). Mine operators that employ an underground degasification system typically also collect gas from sealed areas to (a) reduce gas emissions from sealed areas into the ventilation air course, (b) stabilize the concentration or flow of gas from the underground to facilitate operation of gas movers, and (c) to increase the volume of recovered CMM for commercial purposes.

Rather than installing a collection line through every seal, mine operators will typically select a higher elevation seal, or a seal that is adjacent to a low pressure area of the mine ventilation system (alongside a return entry closest to the exhaust shaft or slope). Mine operators will install collection lines into the waste area (or use abandoned pipelines from underground pre-mining or underground gob gas drainage applications) and integrate installation, including wellhead with construction of the seal. Although not as efficient, collection lines may be installed after construction of seals.

## 4.4 Gas Collection

An integral component of a mine degasification system is the gas collection and transport infrastructure. Underground, this infrastructure serves to move CMM collected from degasification boreholes up to the mine surface. Underground gas collection systems are comprised of a network of pipes fitted with water separation and safety devices:

- water separators that remove accumulations of water in low elevation areas along the pipeline or at the bottom of collection wells (Exhibit 4-7),
- a pipeline integrity system that can sectionalize the collection system and minimize methane liberation into the mine ventilation system should a breech in the pipeline occur,
- vacuum pumps (typically several) that can operate for a range of recovered gas quality and volume (Exhibit 4-8).

On the surface, gathering infrastructure extends from vertical in-seam gas collection wells and gob wells to compression and processing facilities. With most gob wells in the U.S., however, there is no transport or collection mechanism as the recovered gas commonly vents into the atmosphere.

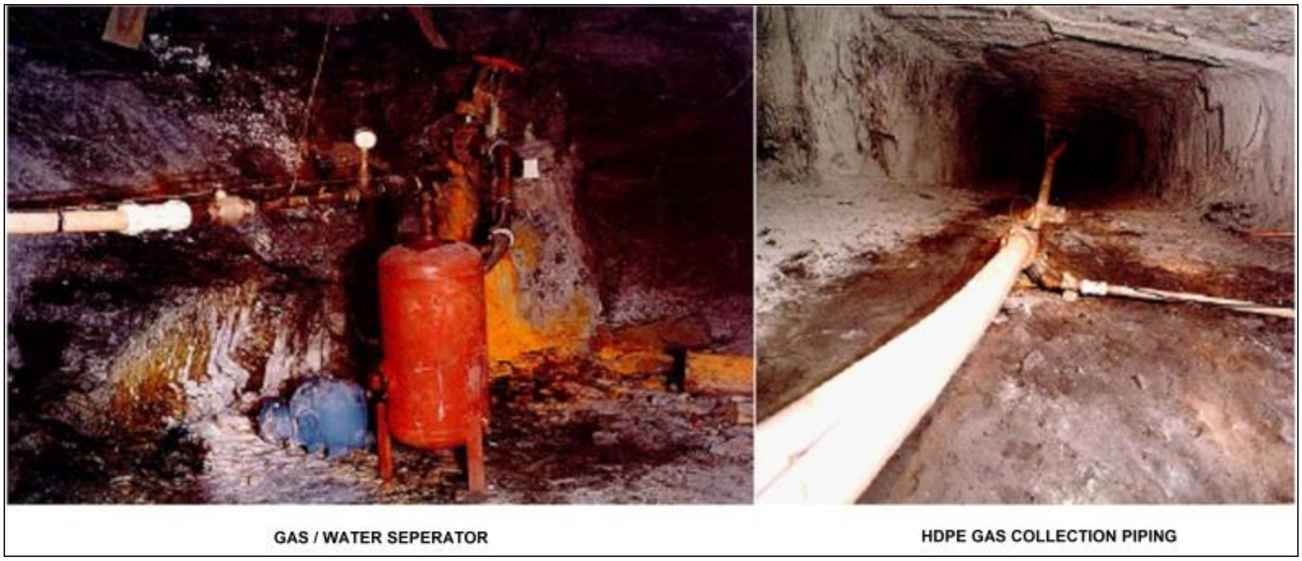


**Exhibit 4-7: Gas Handling and Collection System**

**Exhibit 4-8: Vacuum Pump - Vertical Gas Gob Well**

## 4.5 Methane Drainage Practices at the Hebi #6 Mine

Mine No. 6 implements methane drainage practices in advance of mining to reduce gas content, and subsequent to mining to recover gob gas. Pre-mining drainage practices include:

- face drainage consisting of short fan boreholes drilled in advance of gate developments,
- gallery drainage comprised of short fan boreholes drilled into future longwall panels from galleries driven below the mining seam, and
- cross-panel boreholes drilled from gate entries in advance of longwall mining.

Gob gas drainage practices implemented at Mine No. 6 include:

- horizontal gob boreholes drilled from galleries developed above the mining seam, and
- pipe laid in the gob to recover gas generated from remnant coal, or from sealed gob areas.

**Face Drainage:** Face drainholes are implemented as gate roads are driven, and as dictated by methane emissions during mining. Typically, a series of ten to fifteen holes are drilled 12 meters into the face and fitted with 2 meter long steel standpipes. The holes are drilled to 75 mm diameter and the standpipe diameter is 55 mm. The standpipe is sealed in the holes by means of an inflatable packer which provides about twelve inches of sealing along the annulus between the borehole and the standpipe. Face drainholes are connected to a 200 mm drain line which connects independently to the main underground 300 mm diameter collection pipeline. Typically the mine drains gas from the face drainholes for a period of approximately twelve hours and then subsequently employs these boreholes to set slow burning water-gel based explosives and break the coal for the next lift to advance the heading. None of the face drainholes are drilled outside of the perimeter of the projected heading.

**Gallery Drainage:** Where galleries underlie longwall panels, in particular panels prone to gas outbursts, the mine develops fan holes up into the overlying seam in groups of 9 -15 boreholes, each group is approximately 10-15 m apart. The boreholes are drilled between 75 and 90 mm in diameter up through the coal seam at depths ranging from 5 meters to 10 meters. These boreholes are fitted with a standpipe and are connected to the underground vacuum system. Wellhead pressures range from 100-130 mm Hg, with recovered methane concentrations ranging from 20 to 70 percent, depending on leakage through the collars. Average methane flow rate from a group of boreholes (100 meters of total borehole length) is 12.9 $m^3$ per day. These boreholes also serve to de-pressurize the mining seam and reduce the risk of gas outbursts during subsequent longwall mining.

**Cross Panel Drainage:** The mine drills cross panel boreholes 60 to 80 meters in length from the first upper cut of each gate road on 1.5 to 2.0 meter centers as shown on Exhibit 4-9. The boreholes are drilled to 75 mm in diameter, downward from the up-dip gate, and upward from the down-dip gate. In some cases the boreholes are drilled at angles or are parallel. The mine indicates that the end of the boreholes are 2 to 3 meters above the bottom of the coal seam.

Cross-panel boreholes are collared with 55 mm diameter pipe, 6 meters in length. Standpipes are installed and the annulus is sealed with a chemical (polyurethane) foam or grouting compound. This is done by wrapping 3 meters of the collar pipe with a cotton wrap containing the chemical compound. As this sets (set time about four minutes), it swells sealing the collar pipe into the formation. An additional 3 meters of sand/cement grout is pumped in the borehole outby of the chemical sealant. The mine indicates that this grouting method is not perfect and that mine ventilation air is drawn through poorly sealed collars and reduces the quality of the recovered gas (this was also observed). Recovered gas quality ranges from 30 to 60 percent methane in air, with wellhead vacuum pressures of 70 to 100 mm Hg.

Mine regulations stipulate that longwall mining cannot initiate until the residual gas content is reduced by 30 percent. The average residual gas content of each panel after gate development is approximately 15 $m^3$/t. Typically a 30 percent reduction is achieved with cross-panel boreholes after 6 to 9 months of drainage (9 months for outburst prone panels).

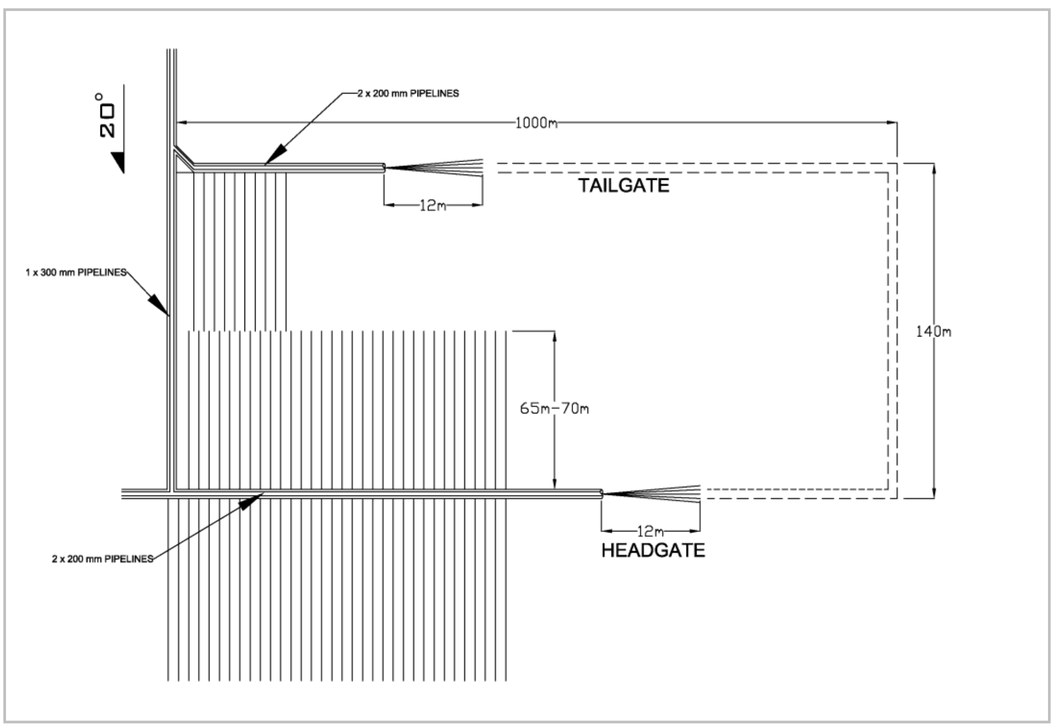


**Exhibit 4-9: Cross-Panel Drainage implemented during Gateroad Advance at Mine #6.**

**Horizontal Gob Boreholes:** Horizontal boreholes are drilled at a location not less than 6 m above the coal seam, from drilling stations developed from overlying galleries or ramps driven from the tailgate road (5 to 6 boreholes are drilled). Drilling stations are approximately 100 to

130 m apart along the longitudinal axis of the panel and boreholes are 110 mm in diameter and drilled to depth of 120 to 150 m (Exhibit 4-10). The drilling stations are placed such that the horizontal gob boreholes overlap about 20 m. The vertical distance (H) between the borehole and the coal seam is derived based on the following equation:

$$H = h/[(1.25\sim1.36)-1] \qquad \text{Eq. 1}$$

where h= the height of the first bench of coal mined.

The horizontal distance between the borehole and the tailgate ranges from 20 to 35 m. This distance is adjusted based on the pitch of the coal seam along the longwall face. For pitches greater than 25 Degrees, this distance is shortened, while for pitches less than 25 Degrees, this horizontal distance is increased.

Typical vacuum pressures applied at the horizontal gob borehole collars are approximately 200 to 350 mm Hg. Recovered gas quality ranges between 20 to 35 percent methane in air and methane flow rates range from 2,000 to 3,300 m$^3$ per day.

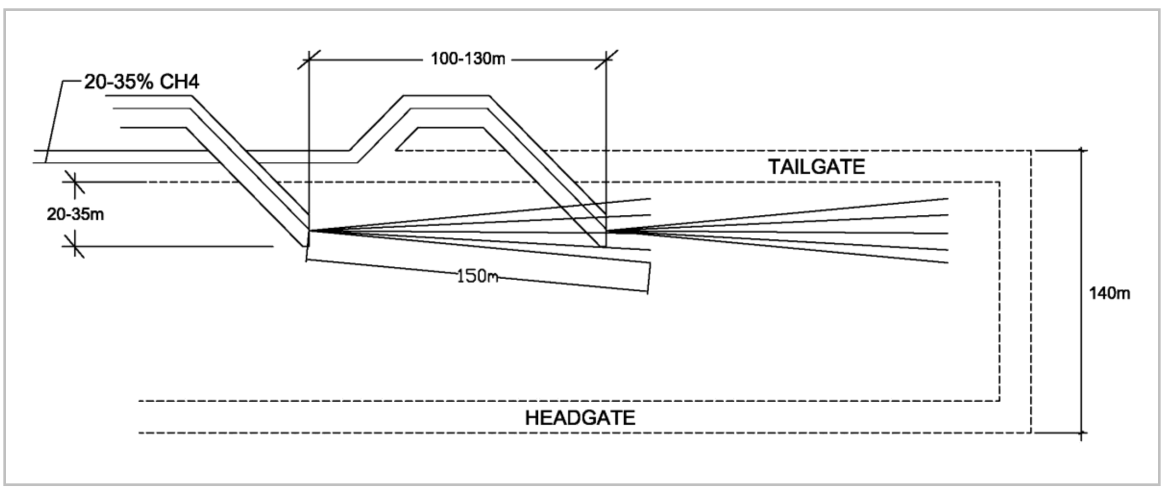


**Exhibit 4-10: Horizontal Gob Boreholes Applied at Mine No. 6.**

**Extraction Pipes in Gob:** Behind the mining face, sets of extraction pipes are installed in the gob, 15 to 20 m apart. These pipes are connected to a 200 mm secondary header along the tailgate side as shown on Exhibit 4-11. This pipe system is connected to the vacuum system at approximately 80 mm Hg and draws methane in air mixtures of 3 to 10 percent at a methane flow rate of between 1,440 to 4,320 m$^3$ per day.

**Underground Gas Collection System:** For the cross-panel boreholes, 10 to 12 boreholes are grouped together into a single recovery collection point via a manifold. The boreholes connect to the manifold with 55 mm rubber hoses. Connections are made with bailing wire. The manifold is connected to a valve, a sample port, and then the 200 mm steel drainage line in the gateroad. Gas quality is monitored for each grouping of boreholes once a week. Approximately 100 mm Hg of vacuum is applied at a typical collection point along the gas gathering line.

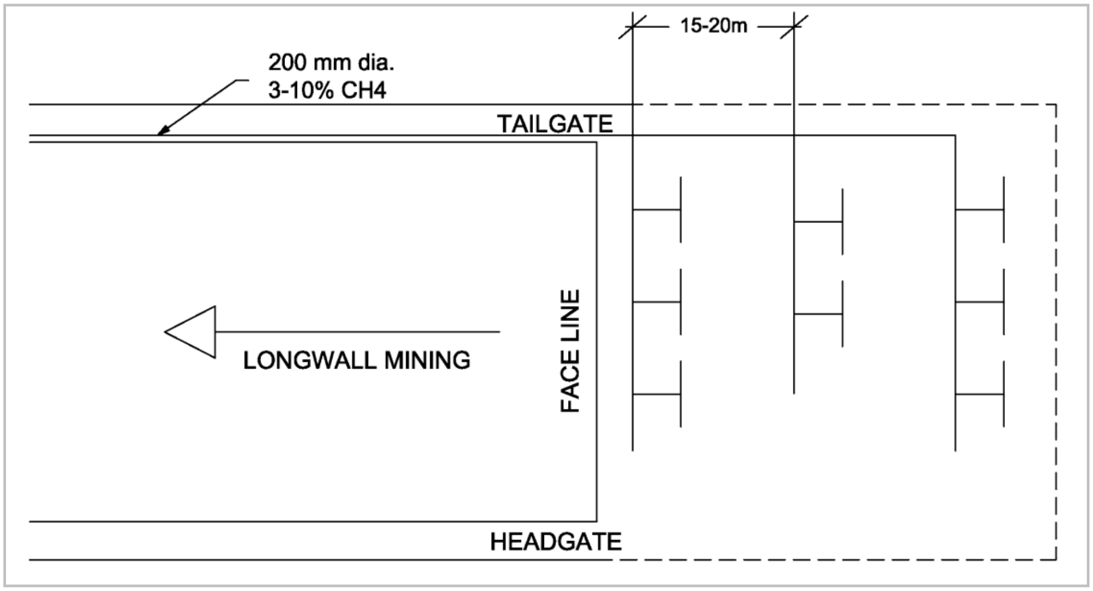


**Exhibit 4-11: Extraction Pipe Gob Degasification Employed at Mine 6.**

Installed underground for gas gathering are 6 km of 200 mm steel pipe, 5,190 meters of 300 mm steel pipe and 800 meters of 400 mm pipe. Pipelines collecting gas from the cross-panel boreholes, face drainage boreholes, gallery drainage boreholes, horizontal gob boreholes and pipes laid in the gob are all separate 200 mm diameter lines, but converge into the main 300 mm gathering line coming from each of the two mining districts.

Monitoring provisions are provided to measure gas flow rate, percent methane by volume and vacuum pressure outby each mining section and at locations throughout the underground gas gathering system.

**Underground Drilling Equipment:**

Drilling equipment implemented at Mine No. 6 for the cross-panel boreholes and overlying gob boreholes are rotary drills designed by the Chonquin Geotechnical Institute, with a capability of drilling to a depth of up to 400 m at a borehole diameter of 89 mm. Drilling depths are limited by geological conditions, stress conditions, and the inability to steer and maintain them in coal; the cross-panel boreholes for example. Underground voltage is 1140 V, which is further transformed to 660, 380, and 220 V for equipment use. The drilling equipment implemented at Mine No. 6 may be electro-hydraulic.

## 4.6 Reservoir Simulations Performed for Cross-Panel In-Seam Methane Drainage at Mine No. 6

Methane drainage engineers use reservoir simulations to optimize current drainage systems and assess the relative benefits of degasification alternatives. For example, simulations supported by history matching with actual gas production data from a system of in-seam cross-panel boreholes can derive, with relative confidence, the necessary borehole spacing and borehole configurations based on (a) time available for methane drainage, and (b) residual gas content targets. These two parameters, including(c) the ability to access reserves by drilling, drive drilling configurations and borehole spacing, particularly as modern longwall mining operations implement "just in time" management practices to balance costs incurred in gateroad development with income earned from longwall shearer passes.

For this study, reservoir simulations were performed of the in-seam cross-panel methane drainage practice currently implemented at Mine 6, and modifications were made to simulator input parameters to generally match residual gas content targets achieved over stated drainage periods. This base model served as the bench-mark for the assessment of alternative in-seam practices and drainage patterns and to develop a recommended approach.

### 4.6.1 Reservoir Simulator

Simulations were performed using COMET3, Advanced Resources' proprietary coalbed methane reservoir simulator. COMET3 is a fully implicit, finite-difference simulator specifically designed for modeling the flow of gas and water in coal seams. The simulator is a triple porosity model that includes the coal matrix and coal cleat system. It includes two-phase (gas and water) flow, that is modeled via gas/water relative permeability curves, and desorption and diffusion processes that are essential for the accurate modeling of gas production from coal seams.

COMET3 is an engineering tool for simulating natural gas and crude oil recovery from unconventional reservoirs. It is an industry accepted, fractured reservoir model, suitable for use in simulating fluid flow in coalbed methane, gas-bearing shale and sandstone, and fractured carbonate reservoirs. COMET3 offers true triple porosity, dual permeability capability for accurate modeling of naturally fractured reservoirs with matrix porosity and gas desorption. Multi-component capability allows better evaluation of enhanced coalbed methane recovery using carbon dioxide, nitrogen or mixed gas injection. COMET3 provides modern and rigorous solution techniques and has a fully implicit wellbore algorithm.

### 4.6.2 Cross-Panel In-Seam Borehole Drainage Model

Seam $2_1$ of Mine 6 is mined using a multi-pass or multi-level bench retreat longwall mining technique. Panels are 140 meters wide by 1000 meters long. After the headgate and tailgate roads are constructed, longwall equipment is installed at the far end of the panel and mining progresses back along the longitudinal axis of the panel to a recovery room. Degassing of the panel is accomplished by drilling cross panel boreholes from the headgate and the tailgate entries, approximately 70 meters into the coal, at 2 meter intervals (Exhibit 4-12). Manifolds connect to the wellheads and gas is transported to the surface via an underground pipeline network.

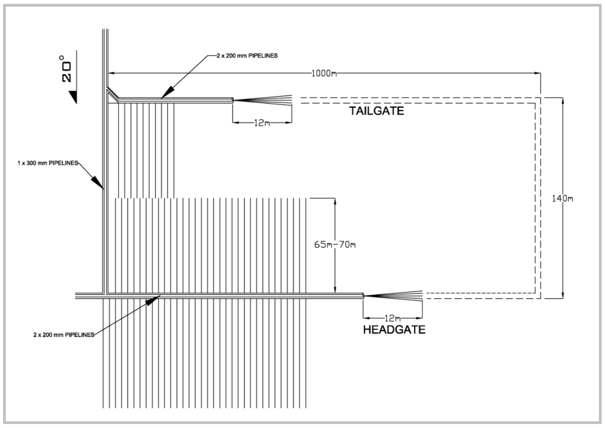


**Exhibit 4-12: Plan view of Hebi mining panel showing cross-measure boreholes.**

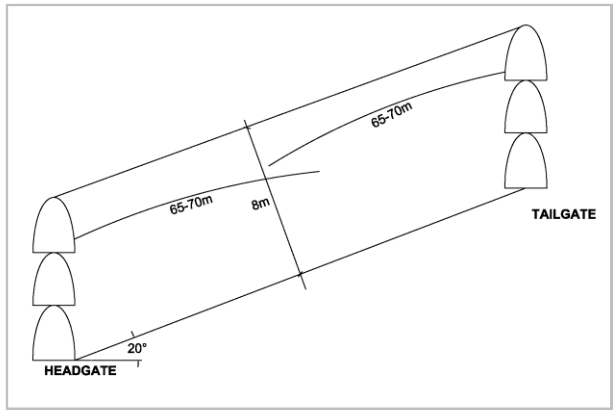


**Exhibit 4-13: Current placement of cross panel boreholes in profiles**

The coal is approximately 8 meters thick, and it is mined in three longwall passes. Because the cross panel boreholes originate and are generally drilled into the upper layer (Exhibit 4-13), degassing through the boreholes ceases after the first layer has been mined and most of the boreholes are mined-through, including the wellheads. After mining of the upper layer, the coal comprising the lower benches fractures as strata is relaxed. This enhances connectivity to natural fracture systems and increases permeability. Methane emissions from the lower benches are controlled by two gob gas recovery methods, overlying horizontal gob boreholes, and pipe manifolds placed into the gob.

Utilizing the principal of symmetry, each pair of cross panel boreholes will behave in the same way; therefore, a model which simulates two cross panel boreholes will provide a proxy for the entire panel. A three dimensional model having 14 grids in the X direction, 2 grids in the Y direction, and 3 grids in the Z direction, for a total of 84 grid cells was constructed.

Dimensions of each cell are 10 meters by 2 meters by 2.67 meters (X, Y, and Z directions respectively). The dimensions of the model, therefore, are 140 meters by 4 meters by 8 meters (X, Y, and Z directions respectively). It would require 250 (1000 meters divided by 4 meters) of these models laid side by side to simulate an entire panel. Exhibit 4-14 is a plan view of the model.

Seam $2_1$ dips 20 degrees from the tail gate to the headgate. Exhibit 4-15 is a cross-sectional view of the model showing that the model has been segmented into three layers vertically, and the 20 degree dip.

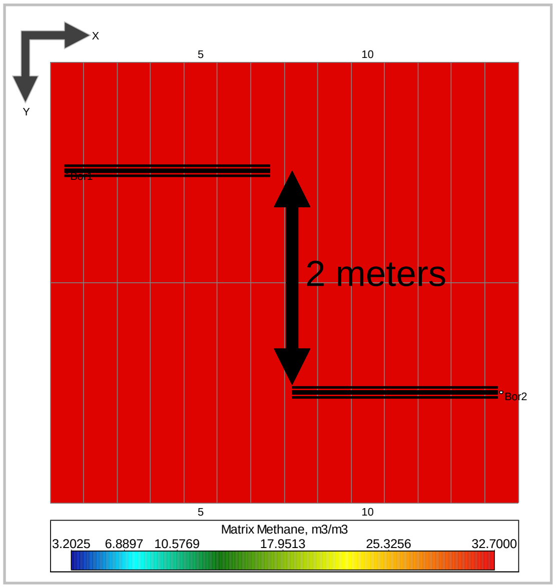


**Exhibit 4-14: Plan view of Seam $2_1$ model.**

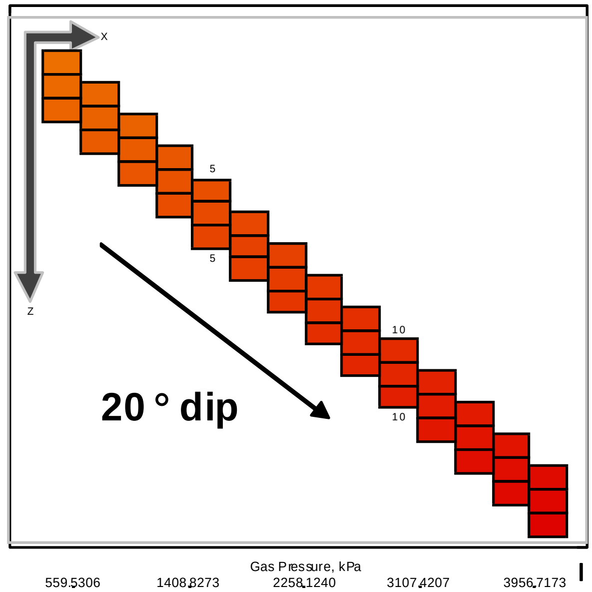


**Exhibit 4 15: Cross section view of Seam $2_1$ model**

### 4.6.3 Discussion of Input Parameters.

The input parameters used in the COMET3 reservoir simulation study are presented in Exhibit 4-16. A brief discussion of each parameter is provided below. Parameters are listed in their relative order of importance in terms of their impact on gas production.

| Parameter | Value | Units | Comments |
|---|---|---|---|
| **Coal Depth** | 350 | meters | |
| **Pressure Gradient** | 0.433 | psi/ft | |
| **Dip** | 20 | degrees | |
| **Initial water saturation** | 100 | % | Coal is under saturated |
| **Permeability** | 0.1 | mD | Kx=Ky, optimized |
| **Vertical Permeability** | 0.1 | mD | Optimized |
| **Porosity** | 6.5 | % | |
| **Sorption Time** | 10 | days | Assumed |
| **Fracture spacing** | 1 | inch | Assumed |
| **Langmuir Volume** | 39 | m3/t | From Taiyuan formation |
| **Langmuir Pressure** | 1792 | kPa | From Taiyuan formation |
| **Initial Gas Content** | 22 | m3/t | |
| **Pore Compressibility** | - | 1/kPa | None |
| **Permeability Exponent** | 3 | | Assumed |
| **Matrix Compressiblity** | - | 1/kPa | None |
| **Water density** | 1 | g/cc | |
| **Water Viscosity** | 0.8 | cp | |
| **Temperature** | 28 | C | |
| **Borehole Radius** | 3.75 | cm | |
| **Borehole BHP** | 15 | psi | |

**Exhibit 4-16: Reservoir Simulation Parameters**

**Permeability** - Initial gas contents are approximately 22 cubic meters per tonne ($m^3/t$). The cross panel boreholes reduce the gas content to approximately 15 $m^3/t$ after about one year of production, and achieve a further reduction in gas content to approximately 10.5 $m^3/t$ after an additional 6 to 9 months. The permeability used in the model was tuned to a value that would approximate these gas contents. As shown in Exhibit 4-16, the base absolute permeability used in the simulations was 0.1 md.

In this model, the permeability between all grid cells is assumed to be 0.1 md. Importantly, the model considers 0.1 md in the vertical direction between layers.

**Relative Permeability** - Relative permeability is a reservoir parameter that describes the degree of effective permeability of one fluid phase in the presence of another fluid phase. Relative permeability is a dimensionless number that is multiplied by the absolute permeability (described above) in order to obtain the value of effective permeability that will be used.

Relative permeability is a function of saturation, and is usually plotted against the liquid (water) phase. The relative permeability curves used in the simulation study are shown in Exhibit 4-17.

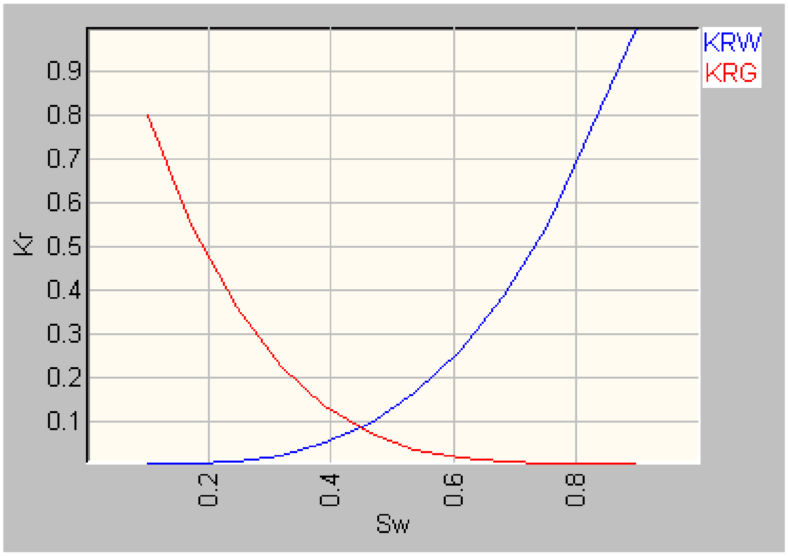


**Exhibit 4-17: Relative Permeability**

**Gas Content** - Initial gas contents are assumed to be approximately 22 cubic meters per tonne ($m^3/t$). The cross panel boreholes reduce gas content to 15 $m^3/t$ after approximately one year of production, and achieve a further reduction in gas content to approximately 10.5 $m^3/t$ after an additional 6 to 9 months (18 to 21 months total).

**Langmuir Volume and Pressure** - The isotherm used in the model simulations was based on analysis of Taiyuan formation coals. For these coals, the Langmuir volume is 39 $m^3/t$ (58 $m^3/m^3$) and the Langmuir pressure is 1792 kPa (260 psia). These Langmuir coefficients are shown in Exhibit 4-18.

| $V_L$ in-situ | | $P_L$ | Gci in-situ | |
|---|---|---|---|---|
| $m^3/t$ | $m^3/m^3$ | kPa | $m^3/t$ | $m^3/m^3$ |
| 39 | 58 | 1792 | 22 | 32.6 |

**Exhibit 4-18: Langmuir coefficients for Taiyuan formation coals**

Exhibit 4-19 is a graphical representation of the desorption isotherm for the Taiyuan formations. As mentioned above, the initial gas content is 22 $m^3/t$ (33.6 $m^3/m^3$). This level of gas content is plotted on Exhibit 4-19 as the orange diamond point, and it can be seen that this level of gas content represents a degree of under-saturation. The level of 15 $m^3/t$ and 10.5 $m^3/t$ are also shown in Exhibit 4-19.

The shape of the curve is described by the Langmuir equation:

$$C = V_L \times P / (P_L + P)$$

Where C is gas content ($m^3/t$), $V_L$ is Langmuir volume ($m^3/t$), $P_L$ is Langmuir pressure (kPa), and P is pressure (kPa).

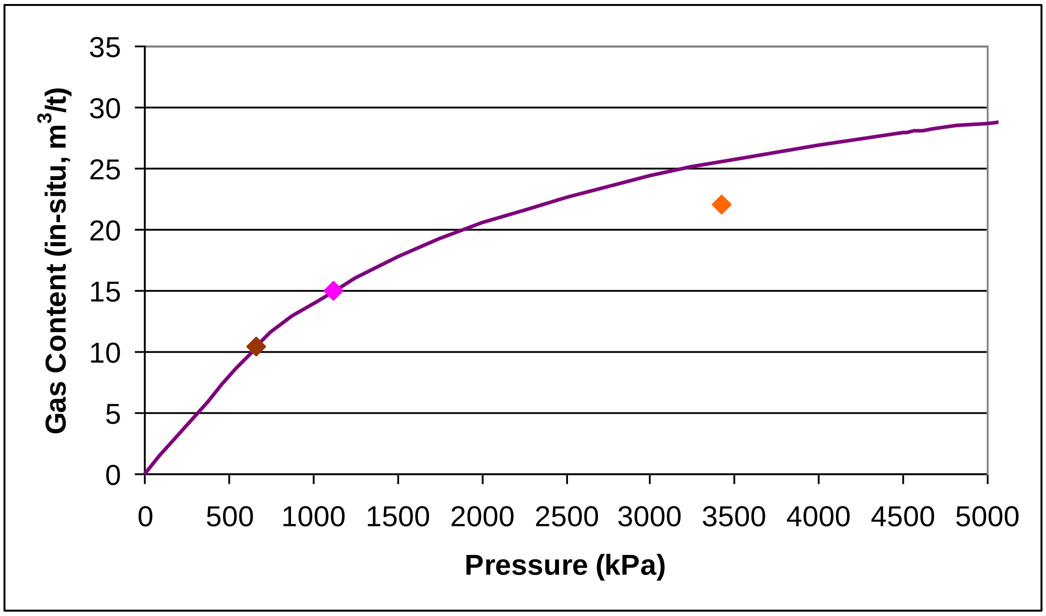


**Exhibit 4-19: Taiyuan formation desorption isotherm**

**Reservoir and Desorption Pressure** - The initial reservoir pressure is a assumed to be 497 psi, which at a depth of 350 meters (1,148 feet) represents a pressure gradient of 0.433 psi/ft. Based on an initial in-situ gas content of 22 $m^3/t$, and using the Langmuir equation, the desorption pressure is 2319 kPa (336 psia).

**Reservoir Thickness** - The coal thickness is taken to be 8 meters. The vertical section of the model has been divided into three equal thicknesses of 2.67 meters each.

**Reservoir Depth** - The depth to the top of the coal reservoir was assumed to be 350 meters, and is determined based on estimated average depth to the top of Seam $2_1$. When the depth of 350 meters is multiplied by the pressure gradient of 9.8 kPa/m (0.433 psi/ft), the result is the initial reservoir pressure of 3,430 kPa.

**Porosity** - Porosity is a measure of the void spaces in a material. In this case, the material is coal, and the void space is the cleat fracture system. A porosity value of 6.5 % has been assumed for purposes of this model.

**Initial Water Saturation** - The cleat and natural fracture system in the reservoir was assumed to be 100% water saturated.

**Wellhead Pressure** - A wellhead or back pressure of 103 kPa (103 psia) was used in the model. In coal mine methane operations, low wellhead pressure is required to achieve maximum gas content reduction.

**Sorption Time** - Sorption time is defined as the length of time required for 63% of the gas in a sample to be desorbed. In this study we have used a 10 day sorption time, which is consistent with the coals in the region. Production rate and cumulative production forecasts are typically relatively insensitive to sorption time.

### 4.6.4 Simulation Results

#### 4.6.4.1 Base Case - Cross Panel In-Seam Drainage Borehole Model

In the base case, the current degasification method using cross panel bore holes is simulated. Permeability is optimized at $K_x = K_y = K_z = 0.1$ mD. No change in permeability as a function of pressure is included. After one year of production from Layer One only, average gas content in Layer One is down to 12.17$m^3$/t (18.13$m^3/m^3$). After an additional nine months of production, the average gas content in Layer One is down to 9.0$m^3$/t (13.38$m^3/m^3$). Exhibit 4-20 graphically illustrates the reduction in gas content in Layer One.

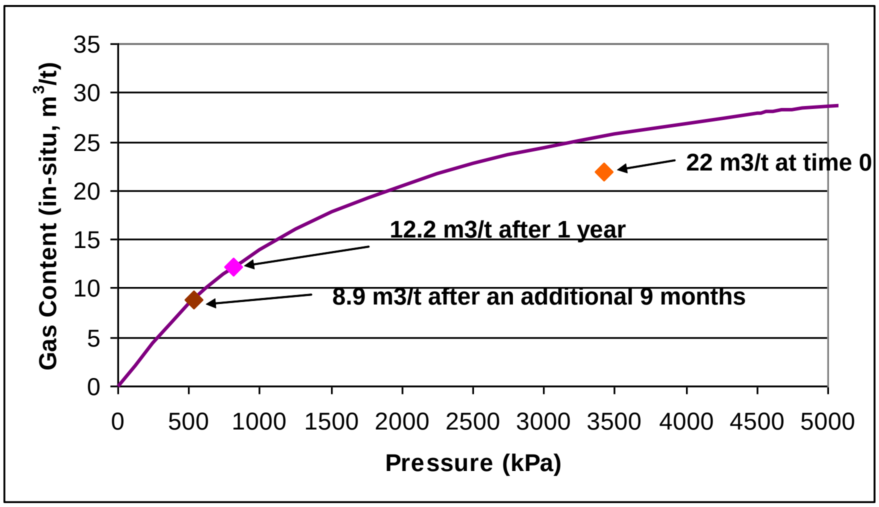


**Exhibit 4-20: Layer One Gas Content Results**

After 1 year and 9 months of production from Layer One, the average gas content in Layer Two has been reduced to 12.22$m^3$/t (18.18$m^3/m^3$). Exhibit 4-21 is a color coded plan view map of Layer Two at 21 months. It can be seen from this map that the distribution of gas content is relatively uniform throughout Layer Two.

After 1 year and 9 months of production from Layer One, the average gas content in Layer Three has been reduced to 13.64$m^3$/t (20.26$m^3/m^3$).

Base case modeling was performed for an additional year, assuming Layer One has been mined. This is modeled by placing two additional cross measure bore holes on production as shown in Exhibit 4-22. Again, there is no production from Layer Two. This was done in order to provide an estimate of the residual gas concentration on Layer Two and Layer Three after Layer One has been mined.

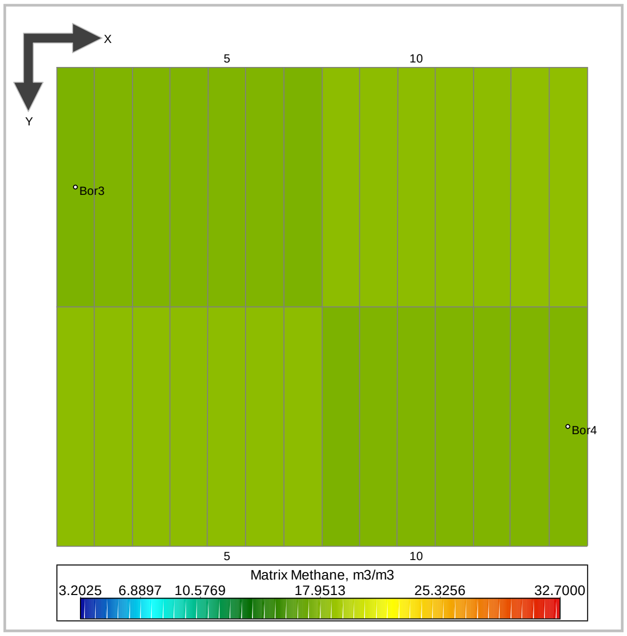


**Exhibit 4-21: Layer Two Gas Content Plan View Map**

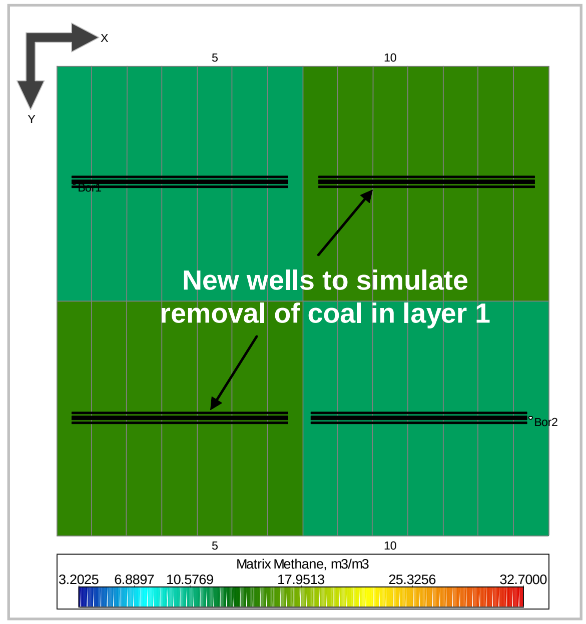


**Exhibit 4-22: Plan view of Layer One simulating Layer One having been mined**

After 1 additional year of production from Layer One, the average gas content in Layer Two is 7.18m$^3$/t (10.66m$^3$/m$^3$). After 1 additional year of production, the average gas content in Layer Three is 8.8m$^3$/t (13.12m$^3$/m$^3$). Exhibit 4-24 is a color coded plan view map of Layer Three at 33 months. It can be seen from this map that the distribution of gas content is relatively uniform throughout Layer Three.

Modeling was performed for an additional year, assuming Layer Two has been mined. In order to simulate this, each grid block in Layer Two is produced as a well, and production from the grid blocks in Layer One is continued. No production occurs from Layer Three. After 1 additional year of production (total model time of 45 months) from Layer One and Layer Two, the average gas content in Layer Three is 4.75$m^3$/t (7.06 $m^3/m^3$). Exhibit 4-23 is a color coded plan view map of Layer Three at total model production of 45 months. It can be seen from this map that the distribution of gas content is relatively uniform throughout Layer Three.

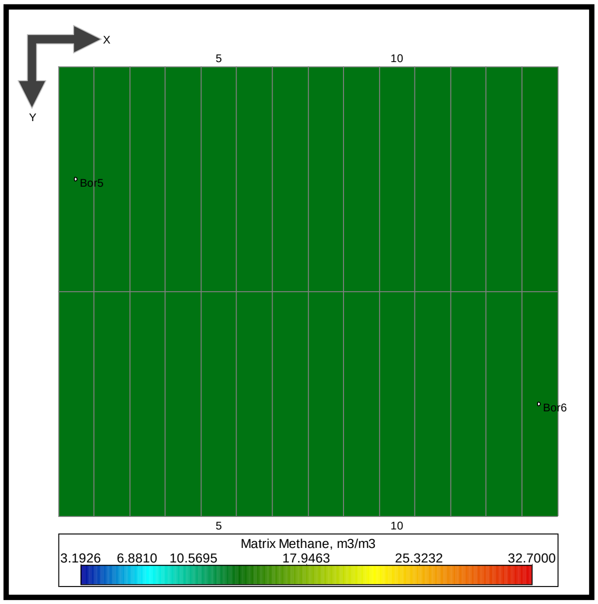


**Exhibit 4-24: Layer Three gas content after 33 months (plan view map)**

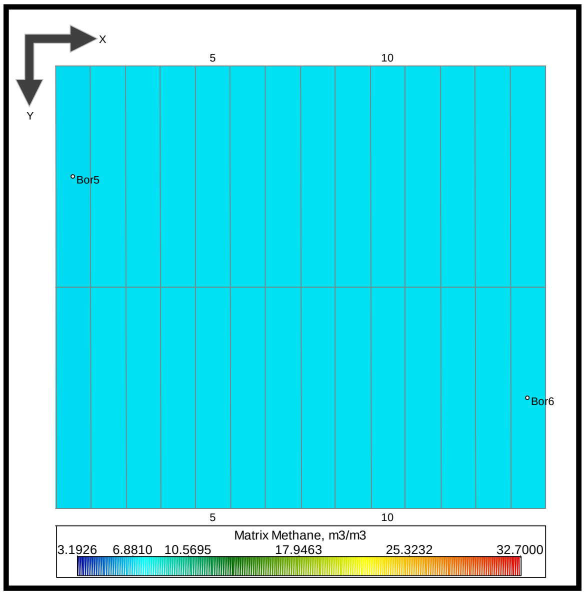


**Exhibit 4-23: Layer Three gas content after 45 months (plan view map).**

Exhibit 4-25 graphically represents the methane produced at the various stages as described above.

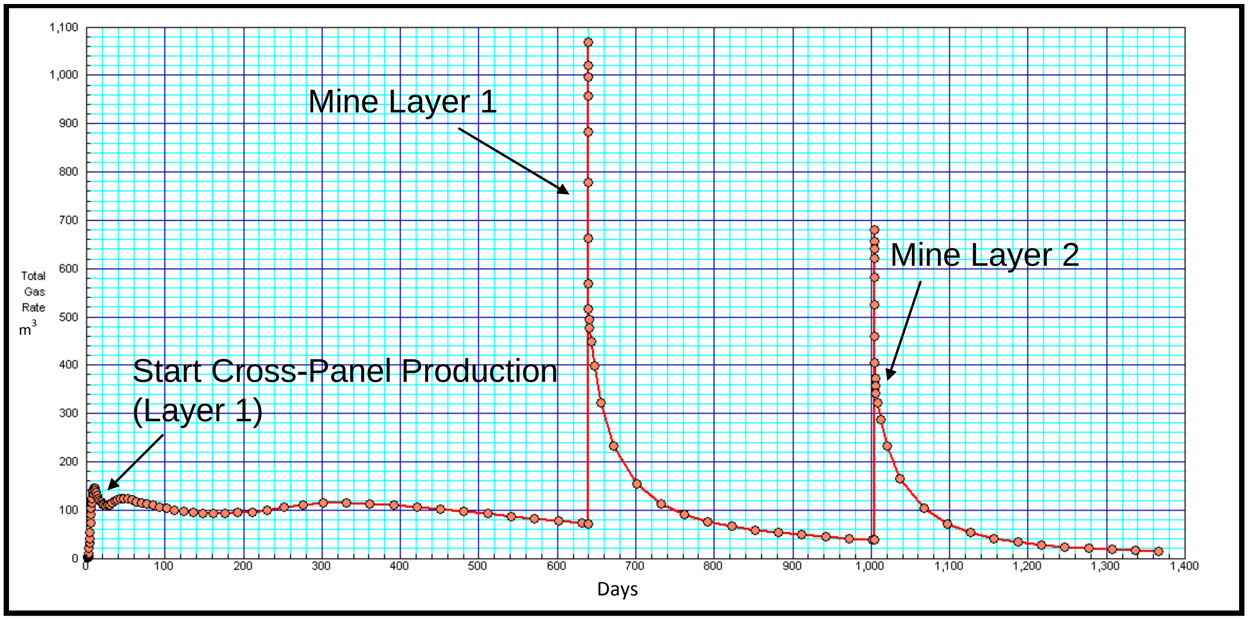


**Exhibit 4-25: Simulated methane production for two cross-panel boreholes, one drilled from each side of the longwall panel for the Base Case**

#### 4.6.4.2 Base Case – Residual Gas Content Parameters

Adjustments to input parameters, particularly permeability, were made to correlate the reservoir model to the general residual gas content parameters provided by Mine 6 engineers. After 12 months both gateroads are developed and all of the cross-panel boreholes are in place. The average residual gas content for Seam $2_1$at this time is 15 $m^3/t$. After 9 months of additional drainage the average residual gas content reduces to 10.5 $m^3/t$. Exhibit 4-26 compares the average residual gas contents predicted by the base case simulation with these key parameters. The simulation reasonably predicts these results and can therefore project the relative benefit of alternative borehole configurations. The residual gas contents projected by the base case simulation after over-mining of layers are also presented in Exhibit 4-26 for comparison with models of alternative in-seam drainage schemes.

| Time (months) | Layer 1 ($m^3/t$) | Layer 2 ($m^3/t$) | Layer 3 ($m^3/t$) | Avg. gc ($m^3/t$) | Key gc ($m^3/t$) |
|---|---|---|---|---|---|
| 12 | 12.2 | | | | 15.0 |
| 21 | 9.0 | 12.2 | 13.6 | 11.6 | 10.5 |
| 33 | | 7.2 | 8.8 | 8.0 | |
| 45 | | | 4.8 | 4.8 | |

**Exhibit 4-26 Base Model Gas Content Projections and Key Gas Content Parameters**

## 4.7 Directional Drilling for In-Seam Methane Drainage

Directional drilling is currently a state of the art practice in the Chinese coal sector and provides mine operators the ability to steer and maintain long horizontal boreholes in coal seams, up to 1,000 m, depending on conditions. Long directionally drilled in-seam boreholes are used by mine operators to reduce gas contents of mineable reserves significantly in advance of mining without having to advance mine infrastructure specifically for drilling (gate roads for example), and provide for more drainage time. In low permeability coals, directional drilling provides for precision borehole placement, either vertically in a thick coal seam for example, or laterally for closely spaced boreholes.

### 4.7.1 Suitability for In-Seam Directional Drilling

At Mine No. 6, Seam $2_1$ is generally consistent in hardness and competence and is therefore considered drillable using rotary and directional drilling techniques, particularly when initiated from entries developed in the coal (gateroads). Because the Mine No. 6 concession is subject to high stress conditions, including coal outbursts, in-seam directional drilling will be limited to around 250 to 300 meters in general, and likely only achieved from entries developed in the coal. The application of this technique to drill in-seam from underlying galleries, for example, may prove difficult due to the outburst prone conditions in some areas. This technique is applicable, however, for the development of long overlying horizontal gob boreholes which could displace the current practice of developing overlying drilling galleries.

### 4.7.2 Benefits of Directionally Drilled In-Seam Boreholes

Directional drilling techniques to develop longer (up to 300 m) in-seam boreholes in advance of mining would provide the following significant benefits to Mine 6:

- Cross-panel boreholes could be steered and maintained in a vertical pattern in the 8 m thick Seam $2_1$ to more efficiently reduce gas content. Tangential boreholes could be developed so that effectively three boreholes reach across the panel at vertical intervals in the coal seam, all from a single collar. This would improve gas content reduction of the lower coal benches and reduce post first-layer mining emissions that are currently controlled by gob degasification techniques;
- Gate roads could advance with minimal additional face drainage, and fewer cross-panel boreholes and therefore fewer borehole collars would be necessary (resulting in improved recovered gas quality);
- Cross-panel boreholes could be drilled from a single gate road (from the tailgate for the panel under development, and from the headgate for an adjacent panel) resulting in reduced drainage time and increased mine productivity;

- Additional coalbed methane reserves could be recovered by using longer in-seam boreholes to target virgin coal areas that will not be mined in the near future (adjacent to longwall panels in pillars, for example), and increase the Mine's CMM power generation capacity.

### 4.7.3 Directional Drilling Equipment

A typical drill rig suitable for longhole in-seam drilling at the Mine 6 is shown on Exhibit 4-27. This equipment is permissible for operation in coal mines and can drill horizontally or at inclinations above horizontal to distances in excess of 1,000 m. A tender unit positioned in a remote location provides the drill with electric and hydraulic power and pressurized water, while a control unit provides for operation of the drill and steering system. Typical water pressure and flow requirements for down-hole drilling are 3.5 to 7.0 MPa and 3.8 l/s, respectively.

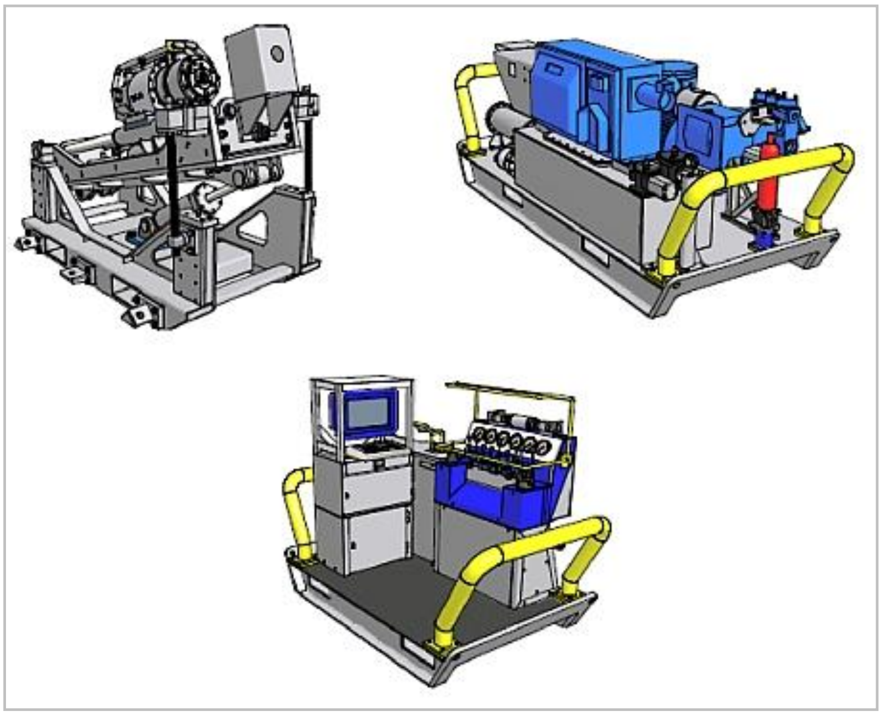

**Exhibit 4-27: Directional Drilling Equipment, Including Drill, Power Pack, and Control Skid**

With directional drilling, a positive displacement hydraulic motor rotates the bit independently from the drill rods using high pressure water. The water is pumped to the downhole motor through the drill rods. The downhole motor consists of a 3 to 4 m long helical rotor fitted inside a high density rubber lined stator. Most of the water discharges to facilitate cuttings removal just behind the bit, and the remainder flows to the front of the bit to assist in the cutting process. Exhibit 4-28 illustrates the motor and bit configuration.

Directional drilling operators can steer the bit with a short bent radius ahead of the downhole motor as shown on Exhibit 4-28. The desired borehole trajectory is achieved by orienting the bent housing opposite to the desired borehole direction as shown.

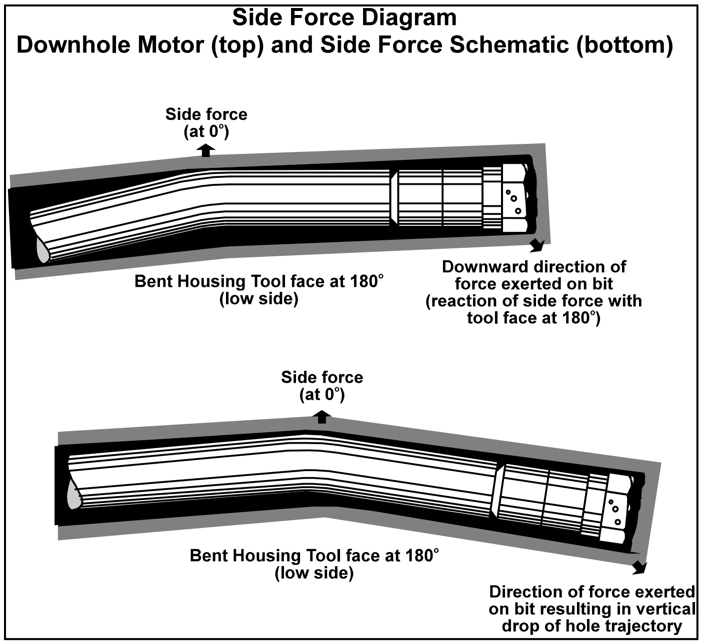


**Exhibit 4-28: Downhole Steering Configuration**

Borehole trajectory is monitored during drilling by surveying techniques. Several techniques are available, including measurement while drilling tools and single-shot tools. Both systems use magnetometers and accelerometers to indicate borehole bearing, inclination, and tool face (bent radius) orientation. With this data, the borehole can be tracked relative to the collar in three dimensions during the course of drilling. Drill cuttings, changes in thrust, and borehole surveys are used to maintain long boreholes in the coal seam. Exhibit 4-29 presents a cross-section of a typical in-seam methane drainage borehole developed with this technique.

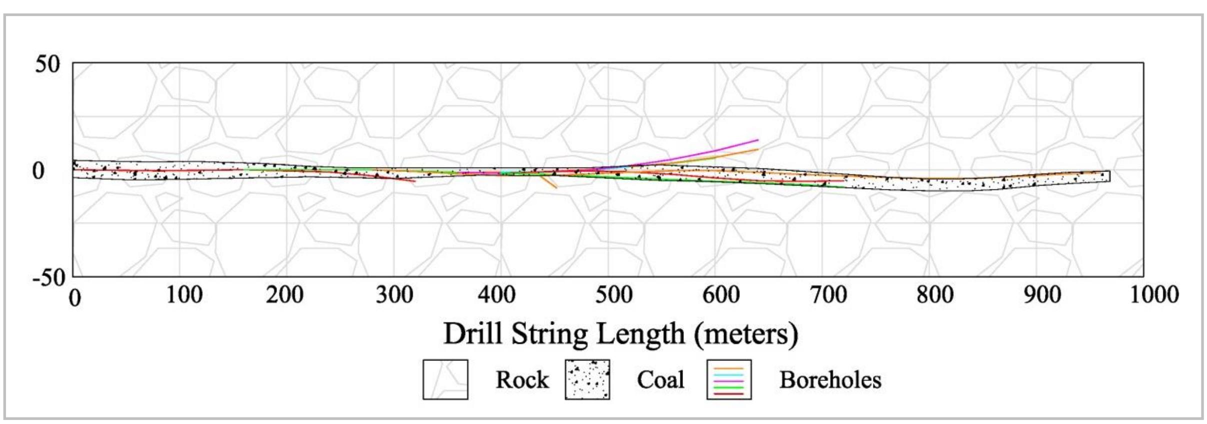


**Exhibit 4-29: Example Profile of a Long In-Seam Methane Drainage Borehole**

### 4.7.4 Recommended Cross-Panel In-Seam Directional Drilling Plan

The current practice of cross-panel drainage (Exhibit 4-13) does not directly drain the lower layers of the coal seam. As a result, the residual gas contents of the lower benches of coal are high, and contribute to significant gob gas emissions which are currently controlled by pipes laid in the gob operated under high vacuum and by overlying gob boreholes. These systems, in particular the pipe manifold system, yield high gas flow rates at very low methane concentrations (sometimes in the explosive range).

A cross-panel system employing directional drilling comprised of a pattern of three (3) longer boreholes, each addressing a specific coal bench in the vertical plane (all from a single borehole collar in the upper layer) as shown on Exhibit 4-30 and Exhibit 4-31, is recommended. Reservoir simulations were used to demonstrate the performance of this system relative to current practices, with the intent to reduce the gas content of the lower coal benches prior to over-mining of the first layer and severing the boreholes.

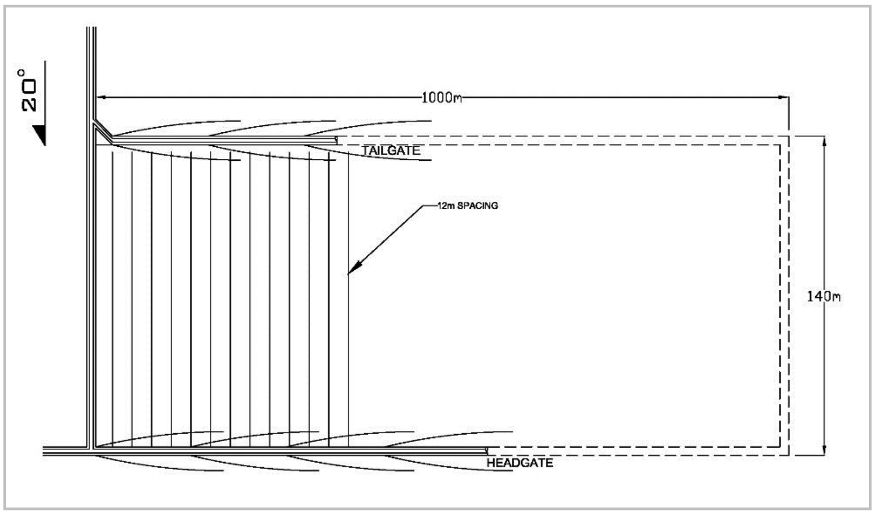


**Exhibit 4-30: Recommended Directional Drilling Cross Panel Approach**

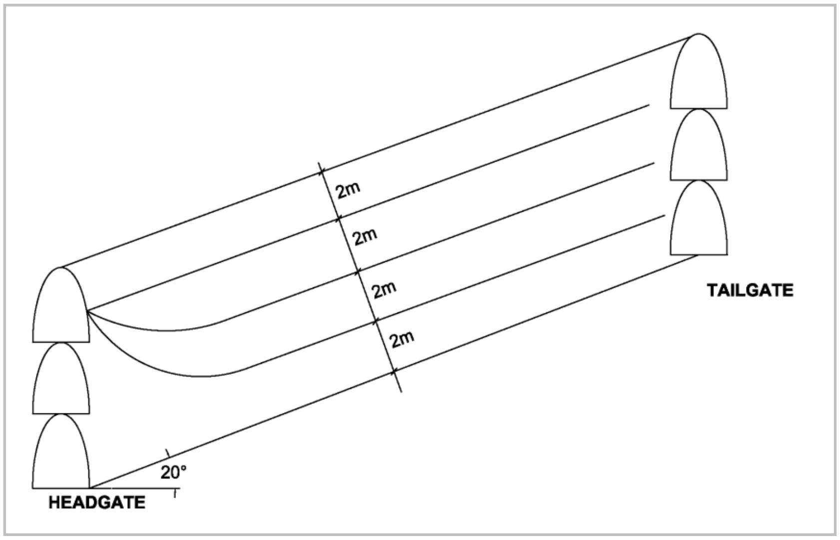


**Exhibit 4-31: Boreholes Steered in Each of the Three Coal Benches**

### 4.7.5 Case Two Reservoir Model

An initial model, Case Two, was developed to determine the lateral borehole spacing of the recommended cross-panel scheme that would provide similar residual gas content results for the first layer relative to that predicted by the Base Case and to evaluate the improved residual gas content reduction achieved for the balance of the coal layers. Case Two provides a comparison to the Base Case with the boreholes producing for 21 months (1.75 years) from all three layers. The initial gas content conditions are same as in the Base Case, 22$m^3$/t.

Exhibit 4-31 shows the concept applied to a longwall panel and Exhibit 4-32 presents the layout of the model for Case Two. Using spacing between the wells of twelve meters in each layer, and after 21 months of production, the average gas content in Layer One is 9.81$m^3$/t (14.6 $m^3/m^3$). This compares to 8.92 $m^3$/t achieved by the Base Case simulation.

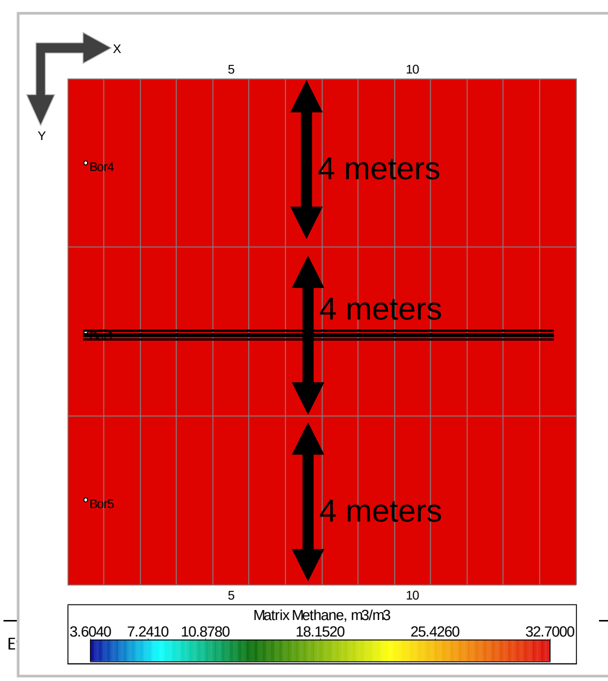


**Exhibit 4-32: Case Two Model**

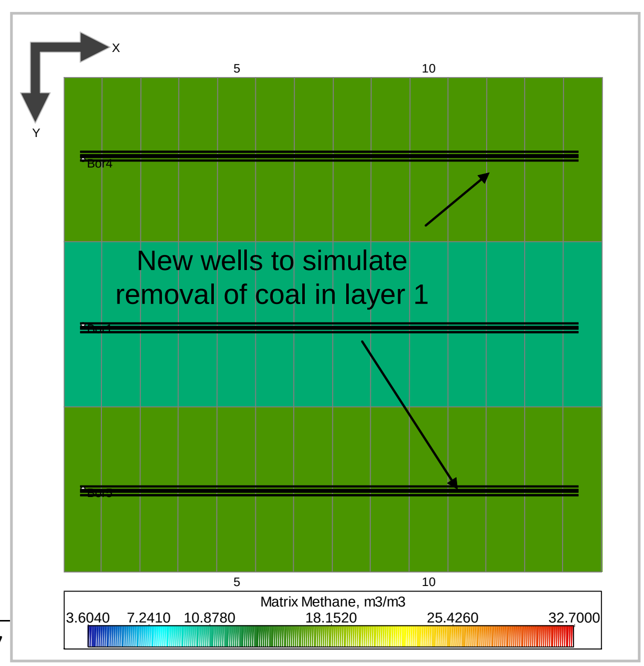


**Exhibit 4-33: All grid cells in Layer One on production to simulate removal.**

The average gas content in Layer Two was 9.87m$^3$/t (14.66m$^3$/m$^3$), and the average gas content in Layer Three was 9.9m$^3$/t (14.7m$^3$/m$^3$). This compares to a gas content of 12.22 m$^3$/t (18.18 m$^3$/m$^3$), and 13.64 m$^3$/t (20.26 m$^3$/m$^3$) in Layer Two and Layer Three respectively for the Base Case. It can be seen that while similar reductions in gas content are achieved in Layer One in both cases, Case Two achieves dramatically greater reductions in gas content in Layer Two and Layer Three relative to Case One.

As with the Base Case, it was desired to simulate the mining of Layer One. In order to do this, additional grid cells are placed on production in order to simulate the removal of the coal. Exhibit 4-33 is a plan view of the (now mined) Layer One.

Production from Layer Two and Layer Three is stopped, as the well head to all tangential boreholes would have been located in Layer One, the layer that has just been mined. This model will provide an estimate of the gas content in Layer Two and Layer Three after an additional year (i.e. 33 months) and will enable a comparison with the previous model.

After one additional year (33 months total), the average gas content in Layer Two is 6.6 m$^3$/t (9.81 m$^3$/m$^3$) as compared to 7.18 m$^3$/t from Case One. The average gas content in Layer Three is 7.8 m$^3$/t (11.6 m$^3$/m$^3$) as compared to 8.8 m$^3$/t from Case One. The model demonstrates that the recommended directional drilling approach will increase gas content reduction while reducing the lateral spacing requirement of the boreholes. Exhibit 4-34 is a plan view map of Layer Two after 33 months, and shows that the gas content is relatively uniform throughout the model.

Again, as in the Base Case, mining of Layer Two was simulated by producing all grid cells in Layer One and Layer Two. Again, no production was assumed from Layer Three as the well heads would have been removed when Layer One was mined. The model was then run for an

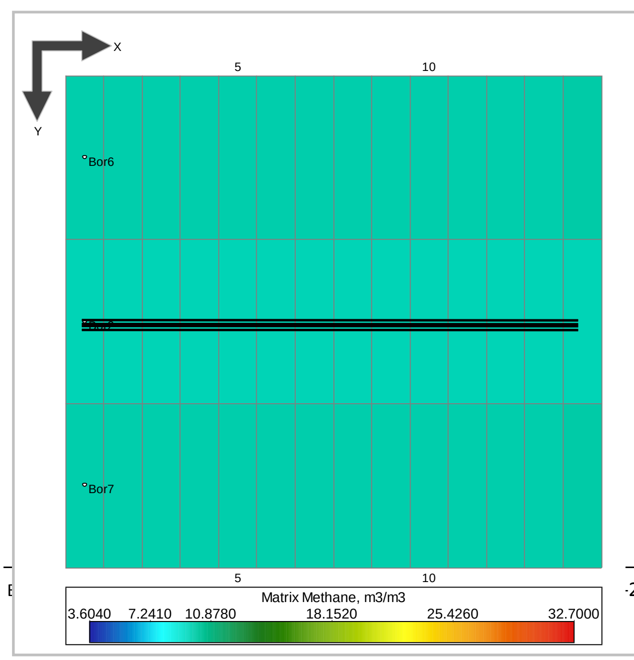


**Exhibit 4-34: Layer Two after 33 months**

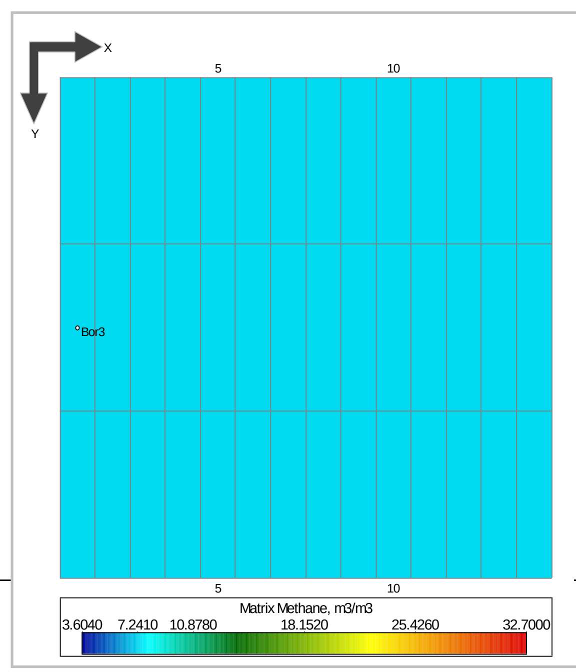


**Exhibit 4-35: Layer Two after 45 months**

additional year, or 45 months total, in order to provide an estimate of the gas content in Layer Three that could be compared with the Base Case.

After 1 additional year (45 total months) of production from all grid cells in Layer One and Layer Two, average gas content in Layer Three was 4.96m$^3$/t (7.36m$^3$/m$^3$), which compares to 4.75 m$^3$/t from the Base Case. Therefore, similar gas content values after mining of Layer Two were achieved in both cases. Exhibit 4-35 is a plan view map of Layer Three after 45 months, and shows that the gas content is relatively uniform throughout the model.

Exhibit 4-36 graphically represents the methane produced at the various stages as described for Case Two above.

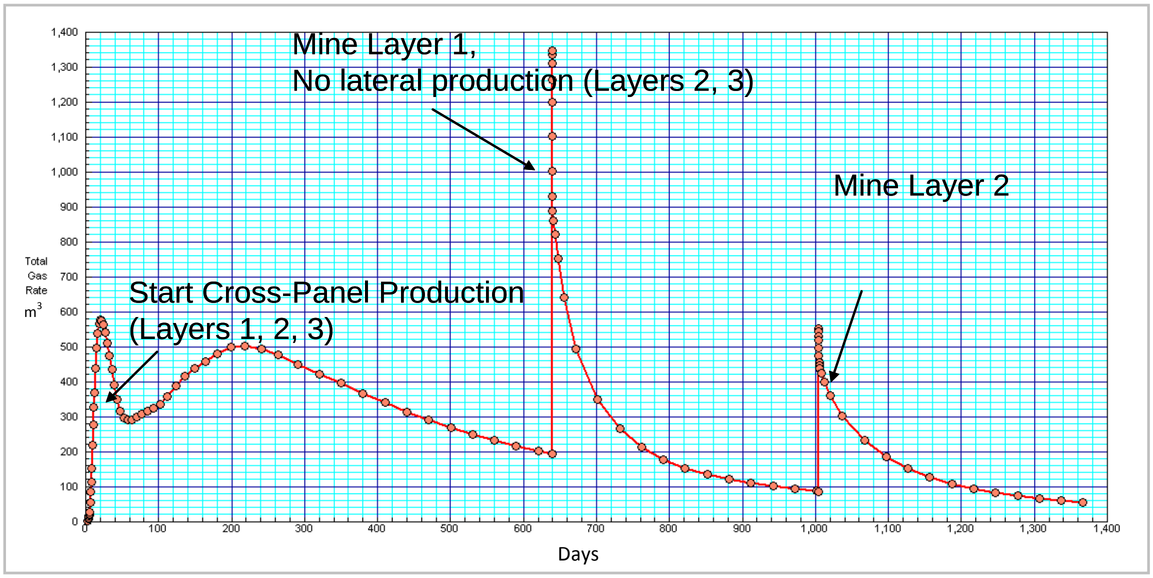


**Exhibit 4-36: Simulated methane production from one in-seam borehole drilled across the longwall panel with three lateral branches at differing elevations, Case Two.**

### 4.7.6 Case Three Reservoir Model

A third case, Case Three, was performed to determine the spacing required for the recommended cross-panel borehole drainage scheme to reduce gas contents similar to that achieved with Case Two but in a shorter period of time. Simulation of gas content after removal or mining of Layer One and Layer Two was repeated with shorter spacing in order to illustrate the benefits. Exhibit 4-37 is a plan view map of the model used in Case Three.

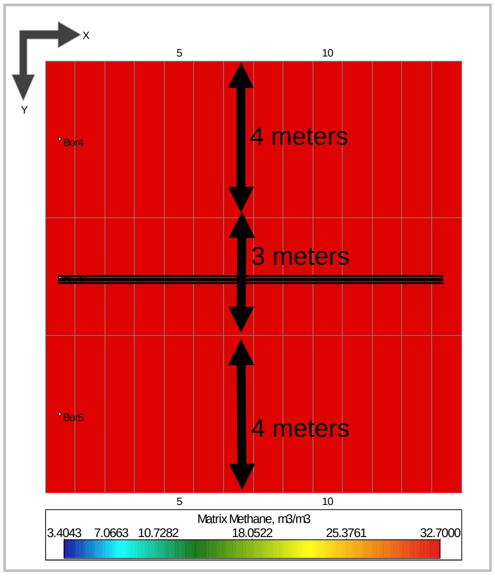


**Exhibit 4-37: Case Three model**

In Case Three, an eleven meter distance between each lateral in each layer was used. It was found that after only 15 months of production the average gas content in Layer One was reduced to 10.9 $m^3/t$ (16.5 $m^3/m^3$). The average gas content in Layer Two was reduced to 11.16 $m^3/t$ (16.57 $m^3/m^3$), and the average gas content in Layer Three was reduced to 11.18 $m^3/t$ (16.6 $m^3/m^3$). This compares to values of 9.87 $m^3/t$ (14.66 $m^3/m^3$) and 9.9 $m^3/t$ (14.7 $m^3/m^3$) in Layer Two and Layer Three respectively, after 21 months in Case Two.

As in Cases One and Two, Case Three also assumed that Layer One is mined. This was done by producing all grid cells in Layer One in order to simulate the removal of the coal, and no production from layers two and Layer Three was allowed as the well heads would have been removed when Layer One was mined (Exhibit 4-38).

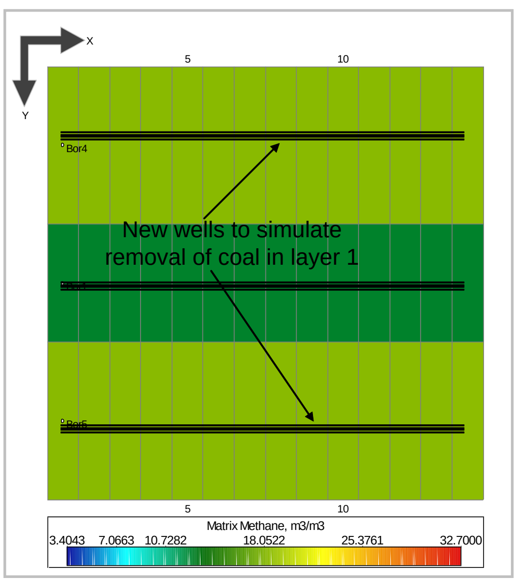


**Exhibit 4-38: Production from all grid cells in Layer One to simulate removal of the coal.**

After one additional year of production from all grid cells in Layer One (2.25 years total) and no production from Layer Two and Layer Three, the average gas content in Layer Two is 7.14 $m^3/t$ (10.61 $m^3/m^3$) and the average gas content in Layer Three is 8.53 $m^3/t$ (12.67 $m^3/m^3$). This compares to values of 6.6 $m^3/t$ (9.81 $m^3/m^3$) and 7.8 $m^3/t$ (11.6 $m^3/m^3$) in Layer Two and Layer Three respectively, after 33 months in Case Two.

A simulation of mining of Layer Two was performed by producing all grid cells in Layer One and in Layer Two and no production from Layer Three was allowed as the well heads would have been removed when Layer One was mined. This simulation was performed in order to provide an estimate of the gas content in the bottom layer after one additional year of production, or a total of 3.25 years. The average gas content in Layer Three after 3.25 years was reduced to 5.1 $m^3/t$ (7.56 $m^3/m^3$) as compared to 4.96 $m^3/t$ from Case Two 3.75 years. From this result it can be seen that average gas content is reduced to a similar value in 3.25 years instead of 3.75 years.

Exhibit 4-39 graphically represents the methane produced at the various stages for Case Three, as described in the preceding paragraphs.

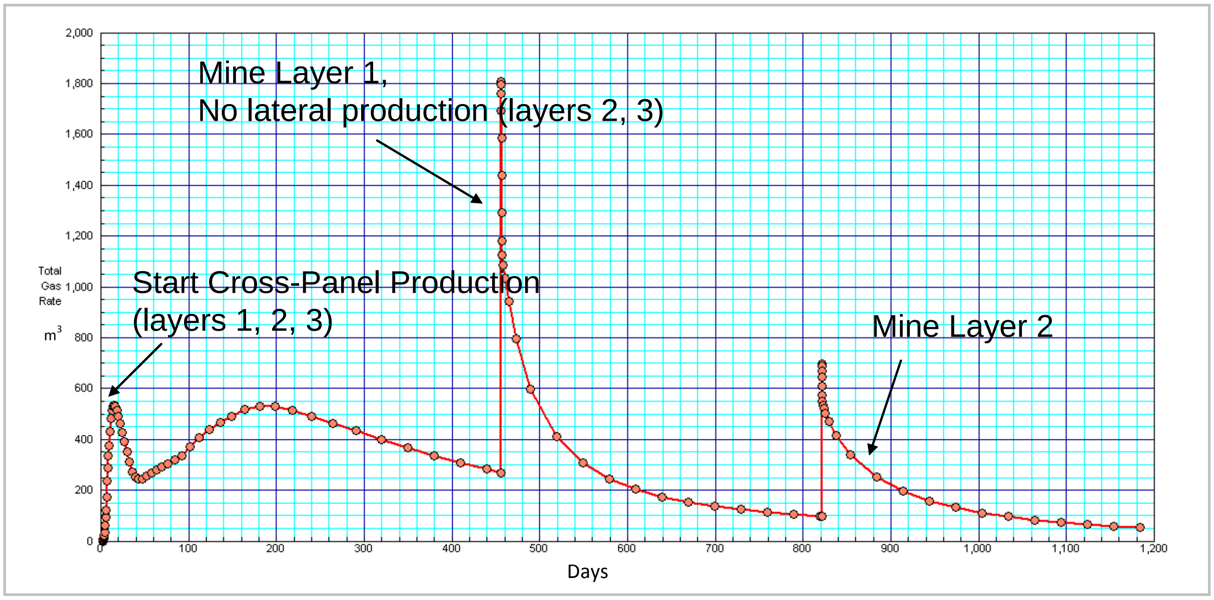


**Exhibit 4-39: Simulated methane production from one borehole drilled across the longwall panel with three lateral branches at differing elevations , Case Three.**

### 4.7.7 Comparison with Base Case Model

Exhibit 4-40 compares the residual gas contents for each layer as a function of time predicted by the Base Case modeling presented in Section 4.6.4 with the residual gas contents predicted by the Case Two and Case Three models. The reduction in gas content achieved in the lower two layers after 15 to 21 months with the recommended cross-panel drainage schemes (Case Two and Case Three) is significant relative to current practice. This gas content reduction is achieved with 50 percent of the number of boreholes and 17 percent of the number of borehole collars currently implemented.

The cumulative gas production figures predicted by the reservoir models were multiplied by the appropriate number of representative symmetrical models in a 1000 m longwall panel (boreholes) to derive cumulative longwall panel gas production. Exhibit 4-41 illustrates the cumulative amount of methane recovered from the cross-panel boreholes and the cumulative amount of methane emitted by the two lower mining layers into the gob for each of the three models simulated. Cumulative gas recovered and cumulative gob gas emissions (from lower layers) are also presented in Exhibit 4-42 in tabular form. The modeling results indicate that the recommended system (Case 2) would recover 24 percent more methane than the current system of cross-panel drainage.

| Case | Time (months) | Layer 1 ($m^3/t$) | Layer 2 ($m^3/t$) | Layer 3 ($m^3/t$) | Avg. gc ($m^3/t$) | Key gc ($m^3/t$) |
|---|---|---|---|---|---|---|
| Base | 12 | 12.2 | | | | 15.0 |
| Base | 21 | 9.0 | 12.2 | 13.6 | 11.6 | 10.5 |
| Base | 33 | | 7.2 | 8.8 | 8.0 | |
| Base | 45 | | | 4.8 | 4.8 | |
| Case 2 | 21 | 9.8 | 9.9 | 9.9 | 9.9 | |
| Case 2 | 33 | | 6.6 | 7.8 | 7.2 | |
| Case 2 | 45 | | | 5.0 | 5.0 | |
| Case 3 | 15 | 10.9 | 11.2 | 11.2 | 11.1 | |
| Case 3 | 27 | | 7.1 | 8.5 | 7.8 | |
| Case 3 | 39 | | | 5.1 | 5.1 | |

**Exhibit 4-40: Comparison of residual gas contents by layer for each model**

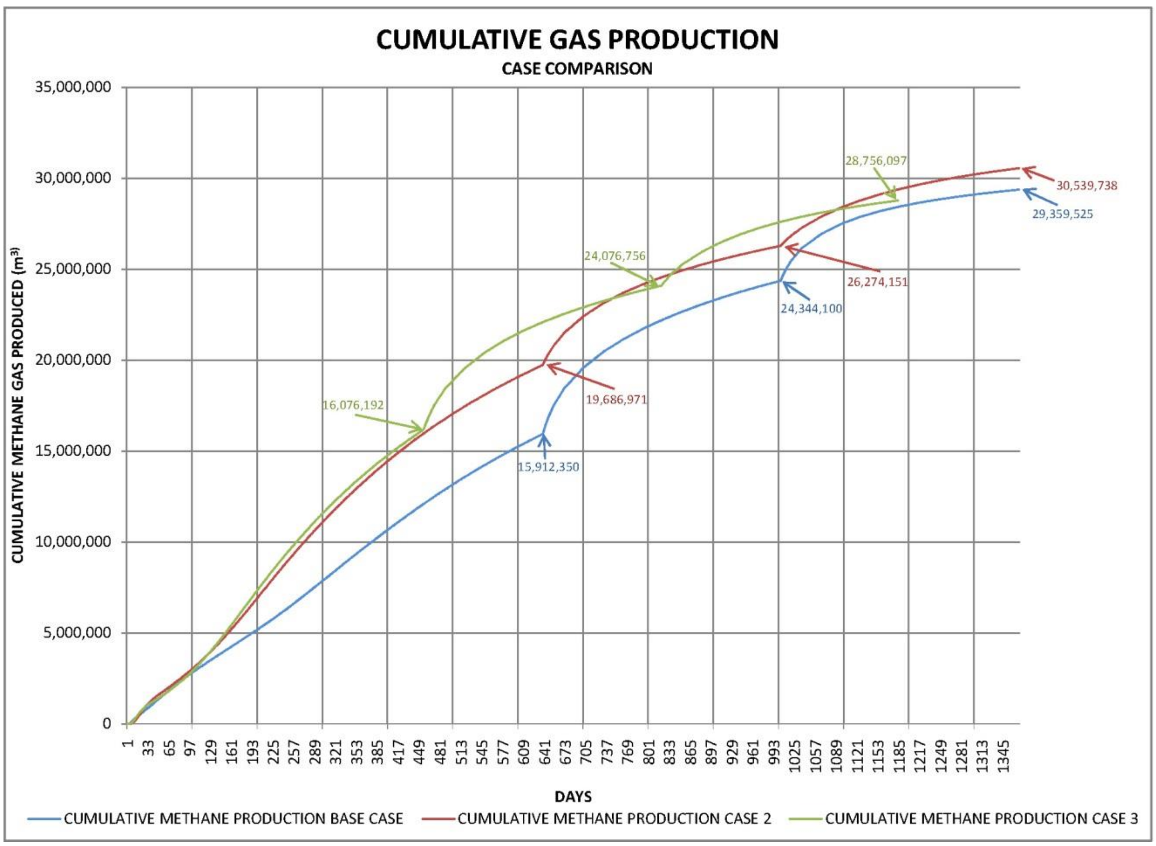


**Exhibit 4-41: Cumulative methane production from longwall panel for each model**

| | CUMULATIVE METHANE PRODUCTION | | |
|---|---|---|---|
| | CROSS PANEL PRODUCTION ($m^3$) | LAYER 2 PRODUCTION ($m^3$) | LAYER 3 PRODUCTION ($m^3$) |
| BASE CASE | 15,912,350 | 8,431,650 | 5,015,525 |
| CASE 2 | 19,686,971 | 6,587,180 | 4,265,587 |
| CASE 3 | 16,076,192 | 8,000,564 | 4,679,341 |

**Exhibit 4-42: Methane production from longwall panel for each model**

In addition, emissions from the remnant coal layers into the gob after the collars of the cross-panel boreholes are severed by mining, are on average 18.5 percent less (22 percent for Layer 2 and 15 percent for Layer 3) than that simulated for current practices (Base Model) as per Exhibit 4-42.

## 4.8 Directional Drilling for Gob Gas Recovery

Reduced gob gas emissions from the un-mined coal layers as simulated by the reservoir models for the recommended cross-panel directional drilling approach, will minimize the need for gob gas recovery systems that produce very low quality gas, such as extraction pipes in the gob. In fact, these emissions may be solely controlled by effectively placed horizontal gob boreholes. Mine 6 currently recovers gob gas using short overlying horizontal boreholes developed from 7 to 10 drill stations along the up-dip tailgate entry. These could be effectively displaced by long, 1000 m horizontal boreholes directionally drilled from the ends of the panel and accomplish similar results.

### 4.8.1 Application of Directional Drilling for Gob Gas Recovery

Directional drilling provides the Chinese coal sector the ability to implement gob gas recovery systems that have demonstrated benefits to conventional practices such as conventional cross-measure boreholes, overlying drainage galleries, or short horizontal boreholes drilled from overlying galleries as presented above. Mine operators can implement directionally drilled horizontal gob boreholes from the current mining level, or from overlying or underlying mining levels. Directional drilling technology provides operators the ability to reach out to distances greater than 1,000 m and steer boreholes to access gob zones from entries that remain intact following mining. This equipment is presented in Section 4.7.3.

Directionally drilled horizontal gob boreholes provide for:

- longer gob gas production periods,
- improved methane drainage efficiencies
- increased gob gas recovery, and
- improved recovered gas quality as fewer boreholes are required (connections to pipeline, etc.).

### 4.8.2 Considerations for the Application of Directionally Drilled Horizontal Gob Boreholes

The objective of gob degasification using horizontal gob boreholes is to provide more immediate and independent access to overlying strata that will fracture as a result of longwall mining. The application enables the operator to place boreholes from non-production areas that are free of equipment and production related inconveniences. It also facilitates placement of boreholes in advance of the mining face for both advancing and retreating longwall systems. With this system of degasification, drainage efficiency and gas purity are impacted by geologic and reservoir conditions, orientation of the boreholes, size and spacing, borehole integrity, suction control, and mine ventilation.

**Longwall Panel Gob Gas Emissions:** Long boreholes, in excess of 500 m, at 100 mm in diameter will recover approximately 15,000 $m^3$ of gob gas per day under high vacuum (100 mm Hg). Larger diameter directionally drilled holes, 150 mm in diameter, for example, have the capacity to recover over 3 times this flow rate for holes between 300 and 500 m in length.

**Geologic and Reservoir Conditions***:* Operators must consider geologic and reservoir characteristics of the overlying and underlying strata when implementing a program of gob degasification using directionally drilled gob boreholes. Specifically, the geomechanical characteristics of the strata, the fracture characteristics of the gob as it forms, the resulting gob permeability, and proximity of source seams to the mined horizon must be considered.

Additional factors to consider include the integrity of the strata for drilling considerations, collected water from upper strata and drilling fluids which can inhibit gas production, particularly for boreholes developed to target underlying sources. Underlying directionally drilled gob boreholes may not produce gas until the water migrates through fractures that will develop during mining. Also, with long directionally drilled gob boreholes, deviations in borehole trajectory can produce water collection areas ("U" shaped low elevation zones), that impede gas flow.

**Standpipe Integrity***:* Directionally drilled horizontal gob boreholes are susceptible to integrity problems. However, they are not plagued by fractures in the vicinity of the standpipe and collar that typically affect cross-measure boreholes. Boreholes drilled from adjacent workings or long horizontal gob boreholes generally originate from competent mine workings and stratigraphic horizons and as such, operators may recover higher quality gas with this technique.

**Vertical Borehole Placement:** When implementing overlying horizontal gob boreholes, operators typically target the lowest contributing source seams and position the holes above the gob rubble zone to take advantage of the fracture network created by longwall mining. Placement in the rubble zone will cause the borehole to shear and can limit its effectiveness to a single low pressure point source over the longwall face, and depending on longwall face activity, draw air from the mine ventilation system. Placement too high above the mining horizon may reduce gob gas recovery efficiency but will produce gob gas with higher methane concentrations. Borehole elevation placement is critical but operators may compensate by drilling larger diameter boreholes which can be lined with perforated steel liner to ensure that they remain intact when undermined. Operators determine optimal elevation placement through trial and error, by drilling boreholes at alternative elevations and monitoring and comparing performance. Some operators install slotted steel liners to aid in maintaining borehole integrity and to improve performance and increase operating life.

**Borehole Orientation:** Longwall panel margin zones, where the overlying strata remains in tension after undermining, produce more gas than consolidated regions within the center of the gob. Horizontal gob boreholes need to target these high permeability zones to improve gas production rates.

**Borehole Size and Spacing**: To develop a continuous low pressure zone over the gob, horizontal gob boreholes are developed at appropriate sizes and spacings so that borehole influence zones overlap slightly. If boreholes are insufficiently sized and spaced apart, gob gas will migrate to mine entries. If boreholes are over-designed and too close together, they may promote migration of mine ventilation air into the gob.

**Borehole Lining:** Lining improves the viability of overlying gob boreholes. Larger diameter directionally drilled boreholes are required to accommodate the perforated steel casing. These boreholes remain intact even when placed too low over the mined panel, and provide protection from air intrusion near the borehole collar. With proper lining (perforated and solid) directionally drilled gob boreholes can produce for long periods of time subsequent to mining.

**Vacuum System Control:** Although gob gas may release without vacuum pressure from horizontal gob boreholes (depending on gob gas volumes, pressures, and the mine ventilation system), connecting to gas collection lines under vacuum pressure is necessary for effective production. In all applications, operators should carefully monitor gas collection system vacuum pressures and methane concentrations to optimize gob gas recovery and quality by adjusting vacuum pressure.

**Mine Ventilation System:** Horizontal gob borehole placement needs to take advantage of the gob ventilation system. Depending on the pressure difference between intake and return air routes, planners must consider the gas migration patterns in the gob so that boreholes target the most productive regions, and mitigate methane emissions into the mine ventilation system.

**Buoyancy:** Horizontal gob borehole placement needs to take into account the structure of the coal seam relative to the longwall panel. Boreholes should be placed along the high elevation side of longwall panels to take advantage of buoyant forces associated with elevation and density differences between methane and ventilation air, when possible. Additionally, horizontal borehole placement relative to the gate entry and borehole spacing should account for the magnitude of the pitch of the seam. For example, for steeply dipping longwalls (panels that are mined on strike), operators will place horizontal boreholes closer to the upper elevation gateroad and at closer spacings than for longwalls that pitch at lower magnitudes.

### 4.8.3 Application of Directionally Drilled Horizontal Gob Boreholes at Mine 6

Mine No. 6 currently drills 5 to 6, 120 to 150 m long horizontal boreholes from overlying drilling stations for gob gas recovery (Section 4.5). These boreholes are maintained in the roof between 7 to 10 meters (“H”) above the top of the coal (upper layer mined) pursuant to Equation 1.

Rather than developing drilling stations in the roof every 100 to 130 m along the tailgate side of the panel, as shown on Exhibit 4-10, several long directionally drilled boreholes could be initiated from the end of the longwall panel from a single drilling station (at coal level or from an overlying ramp) and placed into the roof as generally shown on Exhibit 4-43.

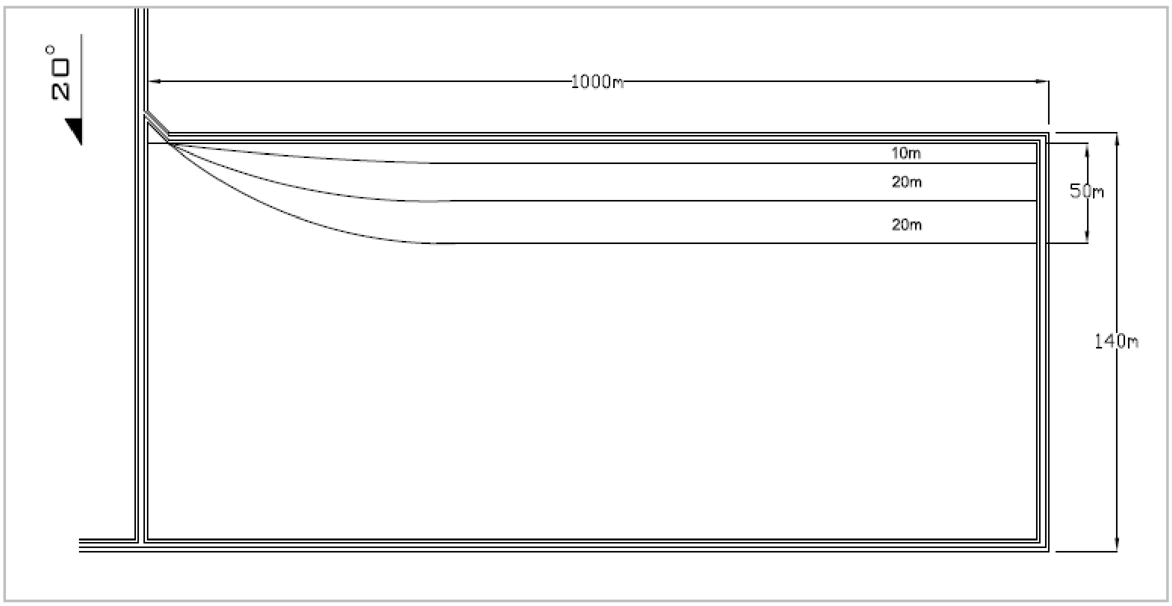


**Exhibit 4-43: Directionally drilled horizontal boreholes applied to a longwall panel at Mine 6**

Successful deployment of this technique at Mine 6 requires proper selection of the vertical placement of the borehole, selection of an appropriate drill site, and knowledge of the deflection capabilities of the drilling equipment. The directional drilling equipment presented in this section can deflect up to 1 degree within 3 meters to build angle and increase borehole elevation when drilling horizontal gob boreholes into the roof from a drill station at the coal level, or to deviate horizontally and place parallel horizontal gob boreholes as illustrated in Exhibit 4-43. This deflection and the initial inclination of the equipment at the drill station is needed to calculate the required borehole trajectory and derive borehole plans.

At Mine 6, the specific vertical target horizon of the long directionally drilled horizontal gob boreholes depends on the Mine’s experience with the short overlying boreholes, the geomechanical conditions of the overlying strata, and the primary source of gob gas. Because the primary source of gob gas emissions is the remnant coal left in the gob (due to the multi-pass longwall mining technique employed), Mine 6 places the short horizontal boreholes very close to the top of the coal seam (7 to 10 m depending on the thickness of the first layer). At this elevation, these boreholes are likely in the rubble zone and effective only for short distances until they are sheared.

Because of the method of mining, the directionally drilled horizontal gob boreholes should remain effective until the first two layers are mined; a significant period of time (up to two years). Also, as fewer boreholes are implemented than current practice, vertical placement must ensure integrity of the boreholes after they are under-mined. While optimal vertical placement will need to be determined by directionally drilling the horizontal gob boreholes at varying elevation and monitoring gob borehole performance (trial and error), Exhibit 4-44 presents a horizontal gob borehole profile concept for initial consideration. The main branch of the horizontal gob borehole is placed safely above the rubble zone, while branches are drilled down into the rubble zone to simulate the current vertical placement of the short horizontal gob boreholes developed from the drilling galleries.

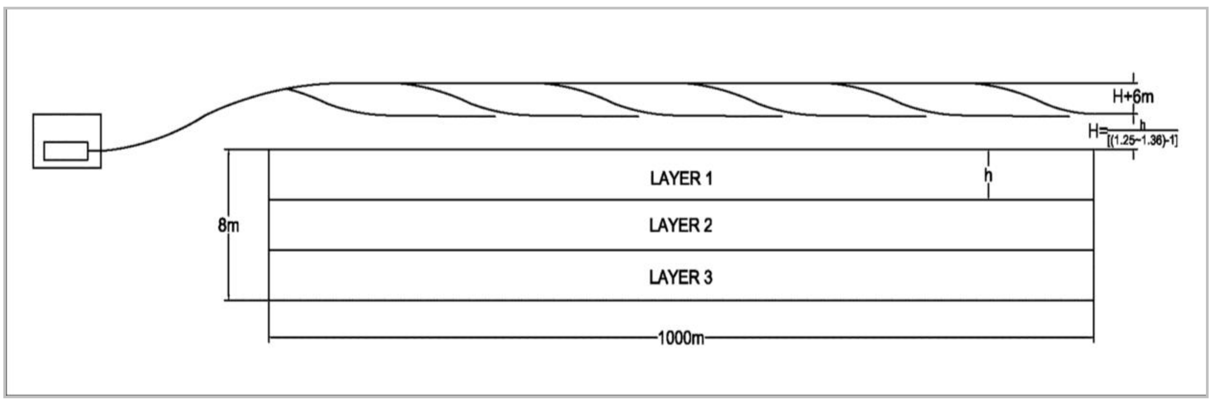


**Exhibit 4-44: Initial Directionally Drilled Horizontal Gob Borehole Concept for Mine 6**

Mine 6 employs 5 to 6 horizontal boreholes drilled from overlying galleries, each borehole producing between 2,000 to 3,300 $m^3$/day of gob gas at 20 to 35 percent methane under high vacuum. Each drill station then produces between 10,000 to 19,800 $m^3$/day of low quality gob gas, or an average of approximately 15,000 $m^3$/day. This is approximately the capacity of one (1) directionally drilled long horizontal gob borehole, 100 mm in diameter based on mine trials under high vacuum pressure. As the horizontal gob boreholes employed at Mine 6 are likely placed in the rubble zone, gas production subsequent to undermining the first bench of coal is likely limited. Assuming these boreholes produce at 1/3rd capacity when under-mined and 130 m between drilling stations, the estimated maximum gob gas production capacity of a horizontal gob borehole system for a longwall panel would be 45,000 $m^3$/day (6 stations at 30,000 total and 1 station at 15,000 $m^3$/day). This volume could be produced from three (3) long directionally drilled horizontal gob boreholes under high vacuum pursuant to mine trials.

## 4.9 Methane Drainage Recommendations for Mine 6

The following recommendations will improve mine safety and increase coal productivity while increasing the volume and quality of the gas drained at Mine 6, and will ensure sustained and increased CMM power generation potential. These recommendations involve the introduction of directional drilling technology for in-seam gas drainage and gob gas recovery, including state-of-the-art wellhead control, gas collection, and monitoring practices.

Two sets of the directional drilling equipment presented in Section 4.7.3 are recommended for broad application at Mine 6 and should be sufficient, because of the reduction in the total volume of drilling with this technique, to service both current longwall mining districts.

### 4.9.1 Directionally Drilled Cross-Panel Boreholes

Cross-Panel boreholes should be directionally drilled at 12 m spacings with three tangential branches to effectively reduce the gas content of each of the three benches of Seam $2_1$as shown in Exhibit 4-30 and Exhibit 4-31. These boreholes should be drilled in conjunction with the first gate road developments as shown.

This technique will reduce residual gas contents to below those achieved with the current system over the same drainage period, particularly for the lower benches. This system will recover 24 percent more methane than current practices. The reduction in residual gas content of the lower benches reduces methane emissions into the gob by an average of 18.5 percent.

The benefits of this system relative to current practices are:

- 50 percent fewer boreholes drilled (counting the tangential boreholes individually);
- 83 percent fewer drill setups, borehole collars, standpipes, and wellheads;
- 24 percent more methane recovered;
- 15 percent increase in gas content reduction after 21 months;
- 18.5 percent reduction in emissions from remnant coal benches in gob;
- may eliminate need for low quality pipe in gob system;
- fewer wellheads minimizes potential for air intrusion into gathering system, improves recovered gas quality;
- fewer boreholes reduces methane drainage costs;
- potential for reduction in drainage time by reducing borehole spacing (see relative benefit from 12 m to 11 m (Section 4.7.7);
- fewer boreholes provides for reduced time required for drilling;
- reduced residual gas contents improves mine safety;
- reduced residual gas contents enables increased coal production.

### 4.9.2 Directionally Drilled Shielding Boreholes

Boreholes directionally drilled in advance of gate development as shown on Exhibit 4-30 reduce gas content and emissions of methane into mining sections. These boreholes should be drilled in conjunction with the cross-panel boreholes and maintained ahead of gate developments as far as possible. Although the equipment specified in Section 4.7.3 is capable of drilling in excess of 1,000 m, stress and outburst conditions will limit these boreholes to 250 to 300 m in length as discussed in Section 4.7.1.

The benefits of this system over the current system are:

- Reduced gas contents in advance of gate development;
- Fewer drill setups to interrupt face advance;
- Structure of coal seam can be defined in advance of developments;
- Outburst zones can be detected further inby gate developments,
- Improved mine safety,
- Increased mining rates.

### 4.9.3 Stand-Pipe and Wellhead Considerations for In-Seam Boreholes

Standard practices for the installation of standpipes and wellhead control measures should be implemented with all directionally drilled boreholes that initiate and stay in-seam, that initiate in rock and are drilled to intercept coal seams or other charged sources of methane.

**Standpipe:** A borehole standpipe is essential for proper well control during in-seam drilling and to prevent intrusion of air subsequent to drilling. The standpipe is typically steel, 6 m in length starting from the outby end, and then PVC, 12 m, with total length depending on the stability of the coal seam at the coal rib. Standpipe inside diameter is typically 100 mm. For a 96 mm diameter in-seam borehole, the procedure is to drill a pilot hole to 18 m in depth. This hole is enlarged to 165 mm with a hole-opener or reamer.

The pipe is installed in the borehole and grouted in place using either of the two methods illustrated in Exhibit 4-45 and Exhibit 4-46, the tremie system (grout pumped through a tremie line), or the pig system (grout pumped down through ID of standpipe).

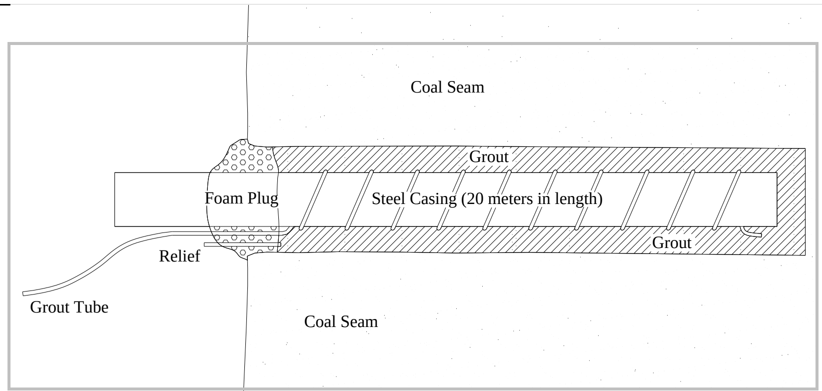


**Exhibit 4-45: Recommended Standpipe Grouting Technique (Tremie Method)**

The installation is pressure tested with water prior to continuing with the borehole (typically around 1 MPa). Subsequent grouting using the pig system can be performed to further seal the annulus of the standpipe should pressure tests fail. The advantages of this configuration are:

- Provides a stable collar assembly to install pressure control systems.;
- Provides a good seal between the coal face and borehole, and minimizes air intrusion and provides for improved recovered gas quality, and;
- Pressure tested to ensure safe conditions prior to drilling.

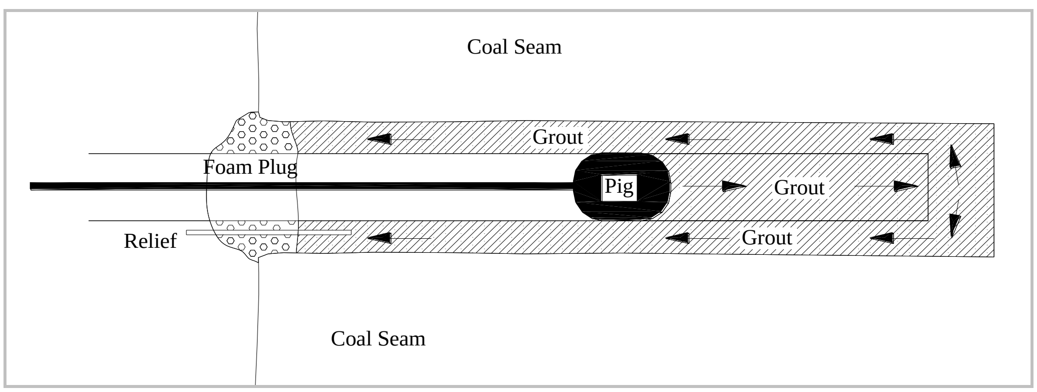


**Exhibit 4-46: Recommended Standpipe Grouting Techniques (Pigging Method)**

**Borehole Pressure Control:** High gas pressures can be controlled during in-seam drilling by using downscaled gas production well blow-out preventer equipment. This unit, shown attached outby a manual valve on Exhibit 4-47, allows the operator to manually seal the borehole annulus around the drill rods (through parallel rams fitted with rubber seals) should high pressure conditions be encountered. Controlled relief of pressure through the drill rods can be performed. The objective of the unit is to control kick-back of the drill rods and relieve pressure when high pressure or high gas flow conditions are encountered. Underground blow out preventers are rated to 20 MPa.

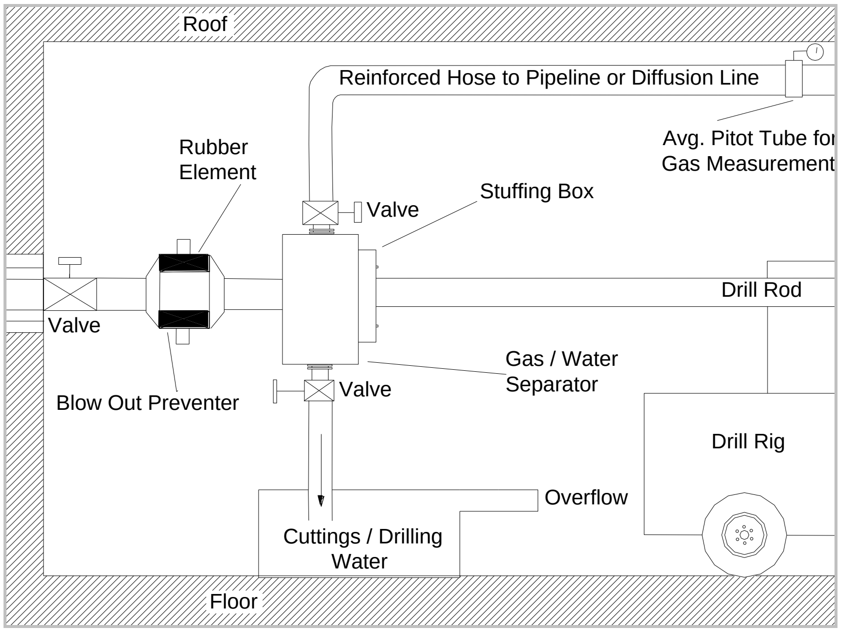


**Exhibit 4-47: Wellhead Configuration During Drilling with Blow Out Preventer**

**Gas Control During Drilling:** Methane generated during drilling can be controlled at the wellhead with proper gas/water separation equipment and gas collection equipment. Exhibit 4-47 shows the gas/water separator connected outby the blow-out preventer. A stuffing box comprised of rubber rod-wipers maintains a seal between the drill rods and the separator. As illustrated on the Exhibit, the stuffing box serves to separate formation and drilling fluids from the gas by density separation and back-pressuring in the water discharge port. The lighter gas flows out of the top of the separator and can be routed to a return entry where enough air is available to diffuse the gas to permissible limits, or routed to the gas collection line.

Benefits of this system relative to current practices are:

- Gas produced during drilling is captured rather than emitted into the mine entry;
- High volumes produced when drilling into gassier areas can be controlled at the collar;
- Drilling will have a minimal effect on inby gas concentrations and mining activities.

### 4.9.4 Directionally Drilled Horizontal Gob Boreholes

Horizontal gob boreholes directionally drilled over the length of the longwall panel along the up-dip tailgate entry as shown on Exhibit 4-6 are recommended. Three boreholes should be developed from three separate collars and configured with monitoring equipment to optimize vertical placement. Initial boreholes should be drilled with tangential branches into the rubble zone as presented on Exhibit 4-44 until an optimal elevation is determined. Three horizontal gob boreholes, 100 mm in diameter, can produce 45,000 m3/day of gob gas under high vacuum. The capacity of this system is similar to that currently implemented with approximately 7 drilling stations per panel with 5 to 6 boreholes drilled per station.

Benefits of this system relative to current practices are:

- Three (3) wellheads per panel compared to up to 35;
- No overlying drilling galleries required saving on infrastructure development costs;
- System capacity is similar;
- System alone could potentially control the reduced gas emissions from the remnant coal (extraction pipe in gob system may be eliminated as emissions from remnant coal is reduced by 18.5 percent);
- Minimizes potential for air intrusion into the gas collection system and provides for improved recovered gob gas quality, and;
- Fewer collars provides for better vacuum control and monitoring.

### 4.9.5 Underground Gas Gathering

High quality gas can be recovered from methane drainage systems that drain gas with in-seam boreholes. This is achieved through the installation of properly sealed borehole standpipes, and using fusible HDPE pipe underground to minimize connections. Higher quality gob gas can be recovered with properly sealed borehole standpipes and by providing monitoring and control provisions. In addition to proper water separation an underground gas collection system should also incorporate a safety system to control methane releases into the mine entries when the pipeline is accidentally breached.

**Use of HDPE Pipe:** High Density Polyethylene (HDPE) pipe prevents leakage at joints as it can by fused rather than flanged together. HDPE pipe is high in strength (rigorously tested for the underground environment in the U.S.) but lighter in weight than steel which facilitates handling. HDPE pipeline systems need to be appropriately grounded (wrapped by copper wire and connected to ground). HDPE pipe is routinely applied underground for methane drainage systems in the U.S., Mexico, and Canada, and has been introduced in China through the United Nations Development Program projects at the Tiefa and Songzao Coal Groups in 1996.

The benefits of using HDPE pipe relative to current practices are:

- Improved gas production through increased suction pressures underground;
- Improved gas quality by mitigating leakage at pipe joints and fittings;
- Ease of Installation;
- Low Maintenance.

**Pipeline Integrity Safety System:** Mine 6 should install impact tubing along its gathering lines to monitor the integrity of its pipelines and improve safety in the event that a pipeline is breached. Impact tubing consists of small diameter, mechanically weak tubing (vinyl or PVC) that is affixed to the gas collection line and pressurized by air or an inert gas such as nitrogen. The integrity tubing is connected to isolation valves equipped with pneumatic actuators at borehole wellheads or at manifolds (connections to several boreholes), and along sections of collection piping. During roof falls, or impact by equipment, the monitoring tubing breaks and activates the corresponding isolation valves, reducing the emission of methane into mine entries should the gas pipeline also break. U.S. guidelines suggest sectionalizing gas gathering systems to limit methane releases to 28.3 $m^3$ per 4.7 $m^3/s$ of ventilating air flowing in the entry containing the pipeline.

A pipeline integrity system is a regulatory requirement in developed countries. The benefits of this system are improved safety.

**Install Provisions for Monitoring:** Horizontal gob boreholes in particular, should be equipped with wellhead configurations that enable measurement of gas quality, gas flow rate, and vacuum pressure. Measurement of the differential pressure across an orifice plate, venturi, or averaging pitot tube may be used to compute gas flow rate; the gauge pressure from the tap inby the orifice plate, venturi, or averaging pitot tube is used to measure static pressure. Samples for quality analysis may be drawn through the taps via a vacuum. Monitoring is useful for optimizing all of the factors that impact the performance of horizontal gob boreholes (optimizing vertical placement and gas quality with vacuum pressure). The direct benefit of this technique is ensuring that the quality of recovered gas from each gob borehole is above the limiting value for the gas gathering system, while the indirect benefit is obtaining a reliable record of gas quality and quantity for system optimization purposes, and enhancing safety.

**Provide for and Maintain Adequate Water Separation:** Accumulated water (drilling fluids, formation water, or condensate) is common either at wellheads or along gas gathering lines, and is a major cause of poor gas producibility at many mining operations. Uncontrolled accumulation of water occurs when entrained water separators, traps, or scrubbing devices cannot properly drain, or if the pipelines are aligned without consideration for water drainage. Where entrained water is a problem, Mine 6 should consider using hands-free float traps to remove water accumulation at lower elevations along the gathering systems, at the base of slopes, etc. Float traps (modified to account for negative pressure) which release water while preventing air intrusion, or water dumping systems for areas operating at high vacuum, would reduce the cost of operations and enhance system performance.

**Monitor the Underground Gathering System:** As stressed above for the horizontal gob boreholes, the negative pressure applied to gas drainage systems has a significant effect on gas production and gas quality. High suction pressures tend to introduce mine ventilation air, while insufficient suction may impair producibility and increase methane emissions into the ventilation system. Pressure monitoring and control capabilities at wellheads and junctions where gas is collected from various systems (cross-panel boreholes, horizontal gob boreholes, etc.) are critical to proper gas quality and production control. Mine 6 should strive to achieve proper pressure control through strategic placement of monitoring provisions and control valves within the gathering system. Frequent monitoring of static pressure and flow meters (orifice plate, venturi, or averaging pitot tube) installed at critical junctions in the gathering system underground will aid in optimizing system performance and will provide the information necessary to ascertain the need for increased system demands.

Benefits are improved systems performance and increased recovered gas quality.

### 4.9.6 Overall Impact of Recommendations

According to Mine 6 engineers, 25 percent of the gas recovered by the underground gas collection system is from gob gas drainage systems; pipe manifolds in the gob, and horizontal gob boreholes from overlying galleries. The average recovered gas quality at the surface vacuum station is approximately 19.5 percent methane in air.

With the recommended methane drainage practices presented herein, high quality gas can be recovered from in-seam boreholes and a well-managed underground gas collection system; up to 90 percent methane in air, depending on the number of wellheads. As these recommended practices reduce gob gas emissions (by an average of 18.5 percent from the un-mined coal benches), and may eliminate the pipe manifold in the gob system which recovers between 3 to 10 percent methane in air, CMM of significantly higher quality is projected for Mine 6.

As Mine 6 can also utilize the directional drilling systems recommended herein to reduce the gas content of Seam $2_1$ from underlying galleries that are developed for other purposes, or by drilling longer boreholes to drain adjacent longwall panels where possible, or by reducing drainage times by reducing cross-panel boreholes spacing (11 m for example), or to target and drain specific areas significantly in advance of mining, an increase in CMM production may be forecasted for Mine 6. This projection, and the anticipated average quality of the recovered gas are shown on Exhibit 4-48.

| CMM Drainage Method | Averaged Recovered Gas Quality (% $CH_4$) | Methane Drainage Rate ($m^3$/day) STP |
|---|---|---|
| Current | 17-21 | 23,000 |
| Recommended | 50-70 | 28,750 |

**Exhibit 4-48: Projected increase in methane drainage volume and recovered gas quality for Hebi Mine No. 6.**

# SECTION 5

# Evaluation of Methane Utilization Technologies

# SECTION 5 CONTENTS

# SECTION 5 EXHIBITS

## 5.1 Introduction

The ability to utilize methane produced from degasification systems has grown with advances in gas processing and power generation technologies. In China, these advances now allow for CMM with methane concentrations as low as 20%[1] to be commercially utilized, and methods for utilizing methane in concentrations of 1% or less (VAM) are currently in the early stages of commercialization. In this section, possible methods of utilizing the drained CMM from Hebi Mine No. 6 are technically evaluated. These include:

- Firing or cofiring boilers for hot water production and space heating
- Direct use (cooking and heating) in residential areas
- Fueling reciprocating engines for electricity generation
- Feedstock for gas enrichment systems which upgrade gas to pipeline quality
- Conversion to liquid natural gas (LNG)
- Conversion to compressed natural gas (CNG)
- Flaring
- Ventilation air methane (VAM) capture to fuel electricity generation

Many factors determine which CMM utilization options are economic, but the most important are usually the methane concentration and produced volumes of drained CMM, and the distance of the mine to potential markets. Hebi Mine No. 6 benefits from being only 15 km from Hebi City, which has large industrial, commercial and residential sectors as potential energy customers. However, the projected produced CMM volumes and methane concentrations of the project are low relative to existing successful CMM utilization projects in China and provide a significant challenge to the economics of several utilization options.

## 5.2 Drained CMM Volume and Composition

The average drained CMM production (not including VAM volumes) from the first six months of 2008 at Hebi Mine No.6 was 23,000 $m^3$ per day (100% $CH_4$), with the gas captured at the surface having an average methane concentration of 19% and a total volume of 121,052 $m^3$. Methane concentrations varied between 17-21 %. Implementing improved pre-mining drainage techniques, along with upgrading the underground gas gathering system (as recommended by this feasibility study and described in detail in Section 4) is projected to lead to an increase in daily methane production to 28,750 $m^3$ (100% $CH_4$), an increase in the average recovered gas quality to 50-70% $CH_4$ and subsequent decrease in total recovered volumes to 41,000-57,000 $m^3$ (better sealing of potential leak points in the gas gathering system results in less ventilation

[1] Using methane with concentrations less than 30% is not recommended or practiced in western countries.

air infiltration leading to less dilution of the gas streams). At 50% methane concentration, the drained gas is estimated to contain between 38-43% nitrogen, 6-11% oxygen and up to 1% carbon dioxide. Current utilization in installed gas engine generators uses approximately 15,900 $m^3$/day, leaving a potential 12,850 $m^3$/day (4.7 million $m^3$ per year) available for possible other utilization.

## 5.3 Firing or Co-firing Boilers

Using drained CMM to fire boilers is common at Chinese coal mines, producing hot water for onsite use and for heating mine buildings or the mine workings. In remote, rural locations, hot water is often piped to nearby residential buildings.

**Exhibit 5-1: CMM Fired Boiler**

(Butler, 2007)

Boilers have the advantage over other CMM uses of being a low cost technology with a short manufacture and installation lead time, and with low maintenance requirements. CMM can be used as a boiler fuel with minimal processing, with most boilers able to accept the levels of $N_2$, $CO_2$, $O_2$, $H_20$ and particulate matter contained in the input methane. However, suitable flame arrestor technology should be installed to prevent flame propagation back into the drainage system. In Western countries, a gas fired boiler rated at 10,000 kg/hr must be fueled by methane at a concentration of 27% or above (Butler, 2007). Boilers can be fitted with "slam shut" valves which activate when methane quality drops below this concentration.

It is possible for existing coal fired boilers to be completely retrofitted with methane burners, although this process comes with an efficiency penalty, as the boilers were built to maximize radiant heat transfer from coal, not gas. The Huainan Coal group has retrofitted 14 boilers at seven coal mines in the Huainan coal field (Anhui Province, SE China). Originally fueled with coal, the boilers now combust 65.8 million $m^3$/year of CMM. Emission reductions from the conversion are estimated at 1.67 $MTCO_2e$ per year. CMM also fuels industrial boilers on a large scale in Jincheng (Shanxi Province). In general though, at most mines in China, using CMM to fuel boilers for hot water production is a small scale project and in these cases, firing the boilers uses only a small percentage of total drained CMM.

Another option for using existing boilers is a partial retrofit with coal and methane cofired in the boiler, providing a low cost, low risk means of improving boiler efficiency:

- The cofiring of methane with coal in a boiler reduces SO2, NOx and particulate emissions when compared to burning coal alone.
- CMM can be injected into different parts of the coal boiler to address a variety of operational concerns such as slag build-up.
- Modern boiler systems can adjust primary fuel feed rates to react to fluctuations in the quality and quantity of input CMM

At Hebi Mine No.6, excess heat from installed electricity generators is used to produce hot water for the mine, negating the use of dedicated boilers. There does not appear to be a large demand for hot water from nearby residential housing or industrial centers, which have ready access to local electricity and natural gas supplies for their energy needs.

## 5.4 Direct Use in Residential Areas

Much of the CMM captured in China is distributed via pipelines to mining communities and neighboring cities for domestic use, mainly cooking. The attraction of this utilization method is that the gas can be used with very little processing other than some moisture removal. Methane concentrations should be greater than 30 percent, although this is not always the case, and consumer's end use equipment is modified to be able to use the low pressure, low concentration gas.

In the past, many residential use projects were installed by local authorities and mining groups as a social consideration but more focus on the economics of gas use is changing this attitude in favor of mine-site electricity generation. A large amount of investment and time is required to construct the necessary infrastructure to supply a domestic gas network. Mine management report that Hebi Mine No.6 has supplied some minor amounts of CMM to nearby residents in the past, but supply pipelines have not been maintained and have degraded to the point where gas is not currently supplied for domestic use.

Depending on geographical location and local climate, demand from domestic users can vary daily and seasonally, especially when gas is used for heating purposes as well as cooking. During periods of low demand, mainly during the summer months, many mines supplying CMM to domestic users vent methane to the atmosphere (ESMAP,2007). But, when mines are located close to a city which generates a large and more consistent demand for gas, and gas supply from the mine is stable, then using CMM for household supply can be a good use option.

CMM has been used for household gas in several large coal mining cities, such as Fushun city, Liaoning Province, and Yangquan city, Shanxi Province, where the Yangquan Mining Group supplies gas to 120,000 households through a main distribution system consisting of three gas holders and 64 km of pipeline. (ESMAP, 2007) Huainan Coal Mine, a state run mine in Anhui Province, supplies CMM to 100,000 households (IEA,2009), and the Shuicheng Coal Mine Group Ltd. in Guizhou Province has developed four local gas systems to supply methane to residential areas. In 2006, the group provided 12 million $m^3$ of methane for residential use while also supplying electricity from installed CMM-fired power plants with nearly 19 MW capacity.

The majority of these projects are only economically feasible with government financial support. For most private mines, such as Hebi Mine No. 6, the initial capital cost of building pipeline distribution systems with associated processing and compression systems, coupled with government controlled gas prices to end-users, makes most such projects uneconomic.

The completion of the West to East pipeline (see Section 3) allowed many cities along its route to convert their main city fuel to natural gas. Hebi City is one such location and is now supplied with natural gas via a trunkline from the West to East pipeline that routes through Xinxiang and Anyang. Hebi City has an extensive gas distribution system which supplies 1.5 million residential users and 700,000 industrial/commercial users. This natural gas competes directly with CMM from Hebi Mine No. 6, which would have to be upgraded to pipeline quality before it could be sold into the Hebi City distribution system. For the CMM from Hebi Mine No.6 to reach this quality, it would have to undergo substantial processing as detailed in Section 5.6 to remove nitrogen, oxygen and any excess amounts of water and carbon dioxide present in the gas stream.

## 5.5 Electricity Generation Using Reciprocating Engines

Most coal mines have significant electricity loads. Electricity is required to run nearly every piece of equipment including mining machines, conveyor belts, coal preparation plants, and ventilation fans. Ventilation systems in particular require large amounts of electricity, running 24 hours a day for most of the year. Generating their own electricity more cheaply than purchasing it from the grid, along with potential electricity sales to the grid, are attractive options for coal mines. Every kW of power that can be generated on site, is one less that needs to be purchased from the grid. Unlike the direct sale of gas to residential users, power generation consumes gas at a steady rate throughout the year, which can lead to higher returns on investment and greater reductions in greenhouse gases.

Using CMM to fuel reciprocating engines for electricity generation is the second most common use of CMM in China (after direct residential use). This has been spurred by a 2008 government regulation, mandating the use of any CMM with greater than 30% methane concentration. As a result, installed capacity from CMM and CBM power generation has risen from 410 MW in 2005 to 920 MW at the end of 2008, with over 1,400 individual generators in operation and connected to the state power grid in 10 provinces. (Yigui, 2009; Huang, 2010). These power plants generated 1.12 billion kilowatt hours of electricity in the first six months of 2009 according to State Grid statistics, with 42 percent being used by the mines and the remainder sold into the power grid.

### 5.5.1 Generator Design and Installation

The main technical challenge in using CMM to fuel gas engine generators is the fluctuation of methane concentration during operation as well as variations in gas quality, pressure, and water content. Several Chinese and international manufacturers produce gas engine generators that have been developed specifically to cope with these variations. See Section 5.11 (Appendices) for examples of these engines and their technical specifications.

As of 2008, 81% of the generators installed at Chinese mines were produced by the Shengli Power Company Ltd, (also referenced as the Shandong Shengdong Group). A further 8% came from smaller Chinese manufacturers including Jinan Diesel Engine Co., Qidong Baoju, Henan Diesel Engine Industry Co., and Zibo Diesel Engine Co. The remaining 11% were imported from international producers including Deutz (Germany), GE Jenbacher (Austria) and Caterpillar (U.S.). Domestically manufactured units have smaller power generation capacity than imported units and produce only 64% of the total installation capacity of CMM power generation in China, while the imported units (only 11% of total units) produce 36% (Yigui, 2009).

Drained CMM must be pretreated before use in reciprocating gas engines. Pretreatment includes filtering the CMM for dust and particles through ten micron filters and then one micron filters, drying the gas to below 80 percent relative humidity and sending the CMM through a fuel train, where the pressure is regulated to between five and 35 kPa. After pretreatment, the CMM is sent through to the generator sets, typically built close to the mining site, and managed with switchgear to provide synchronization, voltage checks, loading and unloading of the engines and overall system protection. If CMM is of sufficient concentration for safe storage it can be stored in above-ground storage tanks (generally 30,000 $m^3$ capacity in China) before pretreatment. Exhibit 5-2 provides an illustration of a typical layout of a CMM-fueled generator set system.

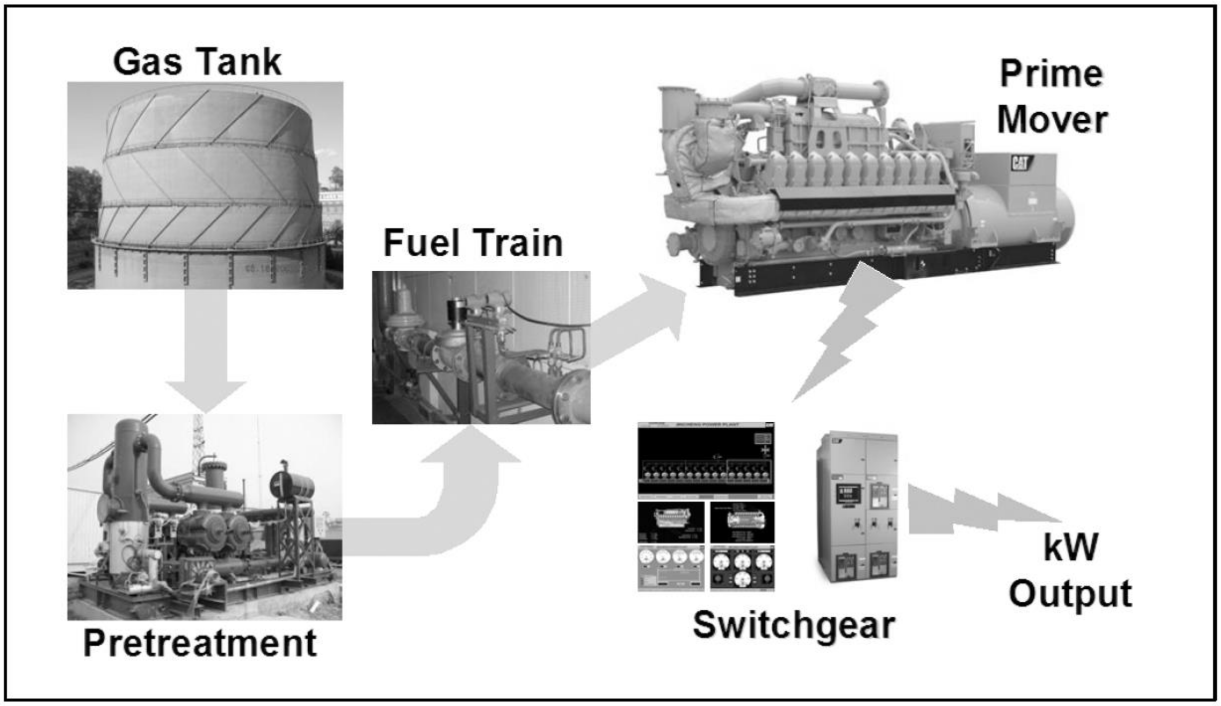


**Exhibit 5-2: Layout Schematic of a CMM Generation Set System**
(Lee, 2008)

### 5.5.2 Use of Low Concentration CMM

China is unique in that authorities have approved the use of generation systems fueled with low concentration CMM (down to 8%). This is within the explosive range of methane (5-15% concentration) and use of such gas would not be possible in countries outside of China. In the West, methane concentrations must be well outside the explosive range (above 30%, or below 2%) for use in electricity generation. But, use of low methane concentration technology is widespread in China. Currently 13 coal production provinces with over 70 low concentration CMM powered generation facilities, produce 3.5 million kWh daily, consuming 400 million $m^3$ CMM annually (Yigui, 2009). One of the largest such plants in China is the 8 MW station installed at the Dawan coal mine in Guizhou Province, where CMM with concentrations down to 8% is utilized. Addressing some of the safety concerns of using CMM in the explosive range, the Shengli Power Company has developed a water-mist transmission system for utilizing low concentration CMM in its generators. Water vapor is injected into the CMM flow at the start of transport to the engine and a dehydration device separates the water vapor from the gas before its use in the generator.

Five such sets are currently in use at Hebi Mine No.6 running on CMM with up to 20% methane concentration. If proposed upgrades to the CMM drainage system are implemented (resulting in higher CMM concentrations of 50+%), then these sets will be modified to run on the higher quality gas. This is considered a straight-forward operation as Shengli Power Company makes almost identical CMM engines that run on higher concentration CMM (Model No. 500GF1-2RW). Exhibit 5-4 shows the similarities in technical specification of the two generator sets.

### 5.5.3 Electricity Generation at Hebi Mine No.6

Hebi's Mine No.6 currently uses drained CMM to generate approximately 50% of the mine's power needs. A power generation plant is located adjacent to the surface vacuum station and is comprised of five Shengli Oilfield Company (Shandong) generator sets (Exhibit 5-3). These sets are relatively cheap compared to other available generator sets on the market. They are modular in design, making it straightforward to add extra sets to an existing generation plant if additional power generation is required.

**Exhibit 5-3: 500 kW Shengli Oil Company CMM Generator Set**

The generator units are modified to operate on the low quality gas (up to 21% concentration) that is currently captured at the mine. The generators are rated at 500 kW, but require significant maintenance and therefore have run times of about 65% on an average monthly basis, resulting in a production rating of 325 kW. As well as generating electricity, heat exchangers on the generator sets heat water for mine use and staff housing. The generation voltage of the engines is 400 volts, 50 Hz and accompanying step-up transformers raise the voltage to 6 kV for connection to the company power grid. The Shengli CMM generator set (500GF1-3RW - utilizing low concentration CMM) specifications are summarized in Exhibit 5-4.

| Genset Type | 500GF1-3RW | 500GF1-2RW |
|---|---|---|
| Methane ($CH_4$) | 9-25% | >25% |
| Electrical Output (kW) | 500 | 500 |
| Voltage (v) | 400 | 400 |
| Aspiration | Turbocharged Inter cooled | Turbocharged Inter cooled |
| Arrangement of cylinders | V-12, 4-stroke cycle | V-12, 4-stroke cycle |
| Engine Speed (rpm) | 1000 | 1000 |
| Fuel Consumption (MJ/kWh) | 10.5 | 9.8 |
| Bore/Stroke (mm) | 190/210 | 190/210 |
| Exhaust Temp. (°C) | <550 | <550 |
| Starting mode | 24v DC | 24v DC |
| Total displacement (liters) | 71.45 | 71.45 |
| Length (mm) | 5678 | 5678 |
| Width (mm) | 1970 | 1970 |
| Height (mm) | 2839 | 2839 |
| Weight empty (kg) | 12500 | 12500 |

**Exhibit 5-4: Shengli CMM Generator Set Specifications**

Figures provided by the Hebi Coal Industry Corporation for 2007, show the total annual electricity consumption of the whole company, including eight working mines and all the support facilities, at about 425 million kWh. The average monthly electricity consumed by the production mines was 30.13 million kWh, with consumption from ventilation fans averaging 6.86 million kWh per month and 14.25 kWh per month being used by the coalmine machinery.

Current electricity generation from CMM at the mine provides approximately 50% of the mine's electricity needs. The other 50% of the mine’s power requirements is provided by electricity purchased from the national and local grid. This is distributed via 110 kV and 35 kV transmission lines to step-down transformer substations in the mining area, which output 6 kV to the company power grid. Site specific transformers then further step-down the voltage to 1,140 v, 660 v, 380 v and 220 v, depending on end use requirements.

Hebi Mine No. 6 currently produces 8.4 million $m^3$ of methane per year, and utilizes 5.8 million $m^3$ per year for electricity generation. With upgraded underground methane drainage systems and techniques in place as recommended in Section 4, produced volumes of methane are estimated to rise to 10.5 million $m^3$ per year. These projected estimates of CMM production suggest that, with the installation of extra generator sets, 90% of the mine’s electricity could be provided from on-site generation. ARI considers the addition of extra generator sets of either Chinese or international manufacture (or a mixture of both) to be technically feasible and the economics of different upgrade scenarios are studied in Section 7.

## 5.6 Processing CMM to Pipeline Quality

Whereas CBM is often of high enough quality to inject into transmission pipelines with minimal processing, CMM often does not meet natural gas pipeline specifications because of its low methane concentrations and high concentrations of contaminants in the form of nitrogen, oxygen, sulfur, carbon dioxide and water. In the U.S., pipeline quality gas must contain less than 0.2% oxygen, less than 3% nitrogen, less than 2% carbon dioxide and less than 7lbs/Mmscf of water vapor, while having a heating value of greater than 967 Btu/scf (EPA, 2008a). In China, pipeline quality gas is defined by the China National Gas Quality Standard GB17820-1999 which stipulates that gas injected into sales pipelines must contain a minimum of 93 percent methane with a minimum heating value of 31.4 MJ/$m^3$ (843 Btu/scf) and minimum amounts of contaminants as shown in Exhibit 5-5.

| $CH_4$ | Min Heating Value | $CO_2$ | Sulfur | $H_2S$ | $SO_2$ |
|---|---|---|---|---|---|
| Min 93% | 31.4 MJ/$m^3$ 843 Btu/scf | < 3% | < 100mg per $m^3$ | < 6 mg per $m^3$ | <3% |

**Exhibit 5-5: China National Gas Quality Standard for Pipeline Gas**

### 5.6.1 A Typical CMM Enrichment Process

Recent advances in technology have given rise to commercially available systems for removing the major CMM contaminants mentioned above. These systems can stand alone, but typically an integrated enrichment facility is installed to remove all contaminants with a series of connected processes at one location. The CMM is processed following some, or all, of the stages in the simplified block process diagram shown in Exhibit 5-6.

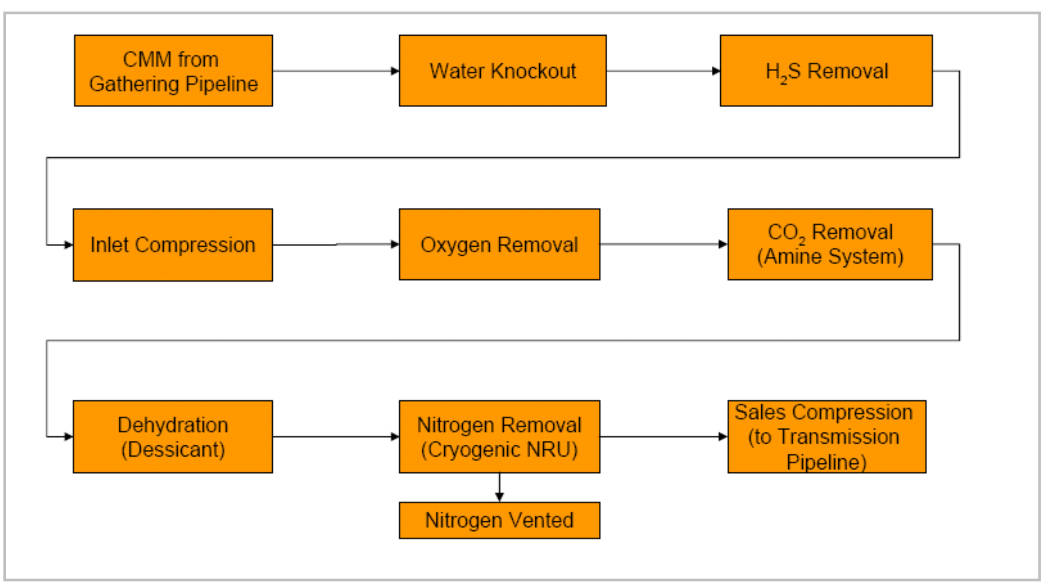


**Exhibit 5-6 Block Process Diagram of CMM Upgrade Facility**

CMM is transported from the mine via HDPE pipelines and basic water removal is performed by expanding the gas stream in separators. Any traces of sulfur in the CMM must be removed in vessels such as the SulfaTreat unit shown (Exhibit 5-7) to prevent corrosion of downstream equipment. The CMM is then compressed from pipeline to plant operating pressures using a two-stage reciprocating compressor.

**Exhibit 5-7 SulfaTreat Vessels**
(Pena, 2007)

Deoxygenation is often the first main step in the CMM upgrading process, as the $CO_2$ removal process is tolerant of only low levels in oxygen and too much oxygen in the nitrogen removal process is an explosive danger. Most gas transmission pipelines in the U.S. have very strict oxygen limits (typically less than 0.1 per cent or 1,000 parts per million). A deoxygenation plant comprising a catalytic oxidation reactor using a platinum coated alumina is shown in Exhibit 5-8. The reaction takes place at 340-370 degrees C (650-700 degrees F) and by-products are carbon dioxide and water.

**Exhibit 5-8 Deoxygenation Unit**
(Pena, 2007)

Several technologies are available commercially for carbon dioxide removal, including amine units, membrane technology and selective adsorption. The units can be highly effective – a mine methane processing plant at an abandoned mine in Illinois, U.S.A., uses an amine unit which reduces the $CO_2$ content of the CMM stream from 8% to 0.005% (Pena, 2007).

Dehydration of CMM is the simplest part of any integrated CMM upgrading plant, but is very important as inadequate water removal can result in serious corrosion to delivery pipes. Molecular sieves (containing alumina) have a proven record and are economical to operate. The unit can also be fitted with a layer of activated carbon to adsorb non-methane hydrocarbons.

Nitrogen removal from the CMM is the most technically difficult process and the most expensive. Nitrogen rejection technologies include cryogenic technology; pressure swing adsorption; solvent absorption; molecular gate and membrane technologies. More details of these technologies can be found on the USEPA's Coalbed Methane Outreach Program's website (USEPA, 2008a). Cryogenic plants have the highest methane recovery rate (approximately 98%) of any of the technologies and their use has become standard practice for large-scale projects where they achieve economies of scale. Cryogenic units tend to be less cost-effective at capacities below 140 mcmd (5 Mmscfd) which are more typical of CMM drainage projects.

The final stage in the CMM upgrade process is to compress the sales gas from the nitrogen rejection unit (NRU). This is normally achieved using several stages of reciprocating compressors that compress the gas for injection into the sales gas pipeline. Exhibit 5-9 illustrates a typical inline set up of the $CO_2$ removal system, the NRU and compressors.


**Exhibit 5-9 $CO_2$ Unit, Nitrogen Rejection Unit and Compressor**
(Adapted from Pena, 2007)

### 5.6.2 Commercial CMM Upgrading Examples

At the end of 2007, seven CMM processing plants were operational in the U.S. (EPA, 2008a). The minimum inlet gas flow to these systems was 42,500 $m^3$/day (1.5 MMcfd) which is over three times that of the available gas flow at Hebi Mine No.6. System vendors supplying CMM upgrading technologies include AET, BCCK, D'Amico Technologies, Guild Associates and MTR. BCCK's nitrogen rejection technology has had commercial success at Jim Walters Resources' mines in Alabama, where CMM with 70% methane concentration is extracted from gob wells and excess nitrogen is removed by the installed cryogenic plant. 2.26 million $m^3$/day (80 MMcfd) of input gas produces 1.13 MMcmd (40 MMcfd) of pipeline quality gas. This project benefits from having compression facilities and gas pipelines already installed at the site and large, consistent volumes of high quality CMM with low oxygen concentration for an input feed.

ARI knows of no projects in China which currently process a CMM gas stream to pipeline quality, although there are projects which use similar technologies to upgrade CMM for liquid natural gas (LNG) production (See Section 5.8).

### 5.6.3 Upgrading CMM from Hebi Mine No.6

The upgrading process described in Section 5.6.1? could technically be applied to the CMM production stream at Hebi Mine No.6, once drainage improvements are made and CMM concentration is above 50%. But the projected low available CMM volumes cause economy of scale problems. Cryogenic removal of nitrogen is not generally considered economic for input gas streams of less than 141,000 cmd (EPA, 2008a) and the process could not be used at Hebi. More suitable nitrogen removal for low volumes of input gas is achieved using Pressure Swing Adsorption or Molecular Gate technologies, although these tend to be more expensive per produced unit cost. International and Chinese companies have had some technical success in creating small skid mounted modular technologies, which can process minimum flows of 14,000 $m^3$ per day. (Mitariten, 2009). Pretreatment processes, along with the need to install significant compression capability and also a delivery pipeline to Hebi city gate, would add significant costs to a CMM upgrading project at Hebi Mine No.6.

## 5.7 Compressed Natural Gas

Compressed Natural Gas (CNG) is made by compressing methane to less than 1% of its volume, allowing it to be stored and transported in strengthened containers at pressures around 200-220 bar (2900-3200 psi). In China, CNG is used widely as a gas source in residential areas and for industrial users, in the heating and cooling industries and more and more extensively as a vehicle fuel.

A typical CNG production system is comprised of an inlet dehydration and filtration system, a compressor and storage tanks. If the CNG is to be used as vehicle fuel, the input methane stream must be dehydrated. Water vapor in the gas is not usually a problem when used for domestic and industrial purposes. But, when compressed to the very high pressures of CNG, any contained water can condense and cause problems within the refuelling station and vehicle fuelling system.

The input gas can also contain other impurities, such as, oil, particulates, hydrogen sulfide, and oxygen. Each impurity by itself or in combination with others can cause systemic problems for a CNG system, both in the production and distribution facilities, and on-board CNG fueled vehicles. The input gas must be filtered to remove such impurities before entering the compressor. Input gas is compressed (sometimes in several stages) up to pressures of 350 bar (5000 psi) with the compressor acoustically enclosed to minimize noise emissions. Produced CNG is stored in strengthened containers before being dispensed to vehicles directly from the production station (Exhibit 5-10) or portable containers can be used to transport CNG to end users (Exhibit 5-11).

**Exhibit 5-10: CNG Compressor Station**

**Exhibit 5-11: CNG Transport Trucks**

China's National Bureau of Statistics reports that the number of civilian use motor vehicles in use at the end of 2008 had reached 64.67 million vehicles, a 13.5 percent increase from 2007. The total number of cars on the roads grew by 24.5 percent from 2007 to 24.38 million. This large increase in vehicular traffic is a major cause of increasing pollution problems in many of China's cities and the use of CNG as an alternative vehicle fuel is being promoted by both the central Chinese government and local governments as one way to reduce pollution levels. CNG fueled vehicles emit 90% fewer particulate emissions than diesel or gasoline powered vehicles, with significant reductions in carbon monoxide and nitrous oxide emissions. Greater use of CNG to fuel vehicles would also go some way to reducing China's increasing dependence on expensive oil imports.

At current prices, it can be up to 40 percent cheaper for Chinese consumers to fuel their vehicle with CNG rather than gasoline and diesel. The costs to convert a car to run on CNG can be as low as RMB 1700 ($250). The number of CNG filling stations in China is increasing, but their distribution is constrained by their distance from the CNG processing plant, which in turn is generally located close to a suitable methane source, whether it is a natural gas field or pipeline, or a CBM/CMM project. The central government is encouraging the building of new CNG filling stations and in the latest economic stimulus plans has included incentives such as a fast-track approval process and credit support from lending institutions.

Companies involved in the distribution of CNG are concentrating on building CNG filling stations in large population centers. Sinoenergy Corporation is a developer and retailer of CNG filling stations and operates a total of nineteen retail CNG stations in eleven locations in Central and Eastern China. Fourteen of the stations are located in Wuhan, the capital of Hubei Province and the largest city in Central China (with a population of over 9 million). Approximately 20,000 taxis and 6,000 buses operate in Wuhan and it is believed that under current market conditions, fueling demand would support at least 80 CNG filling stations, a significant increase over the 30 currently operating.

Closer to Hebi, China Natural Gas, Inc. operates 23 CNG stations in Shaanxi Province and 12 in Henan Province. The company estimates that 60% of its customers are taxis and 35% are bus companies, with a potential market of 70,000 taxis in Shaanxi and Henan Provinces and 22,000 buses in Shaanxi Province alone. The taxi market is further increased by the fact that in China taxis usually run 24 hours a day with three shifts of drivers.


**Exhibit 5-12: Taxis at a CNG Filling Station**

China Natural Gas operates three compressor stations around the city of Xi'an in Shaanxi Province and has a fleet of 33 tankers for transporting CNG from the compressor stations to filling stations. The compressor stations are sourced with CBM purchased from the Shanxi Jinshi Coal Group at a minimum rate of 300,000 $m^3$ per day (10.6 MMcf/d). The gas is purchased for RMB 1.22/$m^3$ ($5/Mcf) and in Shaanxi Province is sold at the CNG pump for RMB 2.35/$m^3$ ($9.8/Mcf) net of value added taxes. A typical Chinese CNG filling station can cost $1.6 million to build and have a capacity of 30,000 $m^3$/day.

The nearest known CNG operation to Hebi is located in Jiaozuo, 115 kms (70 miles) to the south-west. It is supplied by compressed coal-bed methane from Jincheng City in Shanxi Province, which is also the location of a 120 MW CMM fueled power station.

CNG production operations require a consistent volume of input gas with high methane content and little variation in composition. Even after drainage upgrades, CMM produced from Hebi Mine No.6, with a concentration of 50% is of too low quality and produced in too small a volume to be economically used in CNG operations. Extensive processing, similar to that discussed in Section 5.6, would be needed to increase the methane content to sufficient quality for CNG production. The expense of processing, added to the CNG plant capital and operating costs, would likely render the resultant CNG product uncompetitive with the CNG produced in nearby Jiaozuo.

## 5.8 Liquefied Natural Gas (LNG)

Methane liquefies when cooled below its boiling point of - 162°C producing liquefied natural gas (LNG). LNG has a volume approximately 600 times less than that of natural gas and a weight approximately 45% that of water. When stored in special cryogenic containers, LNG is an ideal method to store methane and transport it to areas far from natural gas sources when access to a gas pipeline is not available.

On a large scale, LNG is produced close to major gas fields in the Middle East, Indonesia and Australia and transported by specially constructed ships to energy hungry markets in Europe, Japan, China, India and North America. Many regasification plants have been built, or are in planning stages, on the coasts of these countries. On land, LNG cryogenic containers can be transported by road or rail to potential markets. Truck transportation gives great flexibility in delivery to end users where LNG can be utilized in gas-fired power plants, as a town gas source, in vehicles, and as a peak regulation resource of existing natural gas pipelines.

Technology constraints and economies of scale have historically led to the building of very large LNG plants, producing 4 to 15 million tonnes of LNG per year and needing methane input volumes of 6 to 21 billion $m^3$. Advances in refrigeration technologies have made smaller scale LNG production plants feasible and China is a world leader in small scale LNG production and distribution, using natural gas and high quality CBM as the feed gas.

### 5.8.1 LNG Production from CMM

The use of CMM as a feed gas for LNG production can introduce process problems such as relatively low input volumes, low methane concentration, impurities in the gas, and variability in gas concentrations and volume. In much the same way as when upgrading for pipeline injection (see Section 5.6), CMM must be processed to remove particulates, water vapor, $CO_2$, $O_2$, and trace gases before cooling to produce LNG. Several companies (Chinese and international) have developed technologies which mitigate the aforementioned problems, handling CMM concentrations as low as 40%, and are applicable to small scale LNG production on the order of 8 to 40 tonnes per day (USEPA, 2008b).

A schematic of a possible CMM to LNG production plant is show in Exhibit 5-13. As well as the CMM processing units, additional equipment could include LNG storage tanks for 3 to 4 days of buffer storage, a generator set for project power needs and a truck scale to weigh loaded LNG distribution trucks.

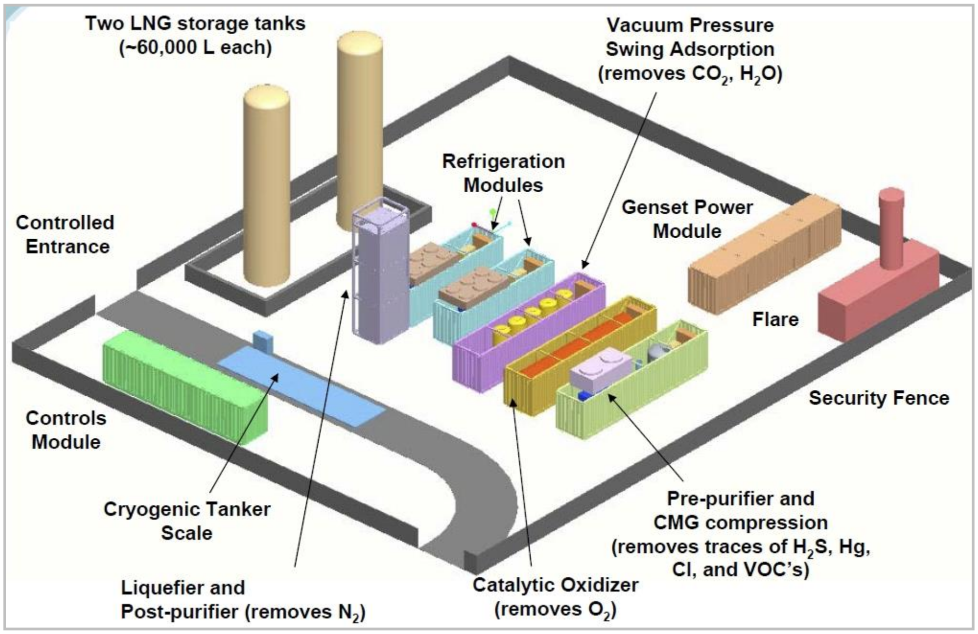


**Exhibit 5-13: Isometric Model of a CMM to LNG Plant**
(Source: Prometheus Energy, 2008)

## 5.8.2 CMM to LNG Projects in China

### 5.8.2.1 Shigang Mine, Shanxi Province

The Yangquan Coal Group Ltd. (YCG), China's largest CMM producer, has constructed a small-scale CMM-to-LNG pilot project at its Shigang coal mine in Shanxi Province (Yang, 2008). The mine currently drains methane at a rate of approximately 14,400 $m^3$/day with a concentration ranging from 30% to 50% (average 35%). The pilot project began operations in the summer of 2007 with preliminary testing using 4,300 $m^3$/day of CMM to produce 1.22 tonnes/day of LNG.

**Exhibit 5-14: Yangquan CMM pilot project - compressor (right) and CMM purifier (left)**
(Yang, 2008)

The plant is Chinese designed and manufactured and utilizes input CMM which has a concentration of 35% $CH_4$, 0.2-0.5% $CO_2$ and the remainder is air. The CMM passes through a purification system and low pressure compressor (Exhibit 5-14) before low temperature CMM separation technology is used to remove oxygen and nitrogen and produce the LNG. The final product is 99% $CH_4$ and is stored on site (Exhibit 5-15).

**Exhibit 5-15: Yangquan CMM pilot project - refrigeration tower (left) and LNG storage tank (right)**
(Yang, 2008)

The mine has plans to increase coal production and improve methane drainage and is looking for investors to finance the building of a $7.5-million plant capable of handling up to 260,000 $m^3$/day of CMM (35% $CH_4$) in the production of 20,000 tonnes/year of LNG. The LNG would be re-gasified and used in the local town gas system (M2M, 2010).

YCG also has a project in the idea stage for the Hezuo Mining Area in Shanxi Province. The proposed CMM liquefaction plant would utilize 125 million $m^3$ of gob gas in the production of 100,000 tonnes LNG per year (M2M, 2010).

#### 5.8.2.2 Songzao Coal Field, Sichuan Province

The Chongqing Energy Investment Group (CEIG) and its subsidiary Songzao Coal and Electricity Company (SCEC) are actively developing a CMM to LNG project which will gather, purify, and liquefy as much as 130 million $m^3$ (100% $CH_4$) annually of medium concentration CMM from six operating coal mines in southwest China. The resultant LNG will be transported by truck for consumption both locally and in growing natural gas markets in south and east China. If successful, an additional plant with 40 million $m^3$ annual capacity will be added (M2M, 2010).

### 5.8.3 CMM to LNG at Hebi Mine No.6

The technologies discussed in the previous sections appear to be technically feasible for production of LNG from CMM at Hebi Mine No.6. However, the available CMM volumes at Hebi are 7 and 27 times lower respectively than the estimated available volumes of the proposed projects at Yangquan and Songzao. It is calculated that Hebi Mine No. 6 has a maximum possible LNG output of less than 3,000 tonnes per year.

## 5.9 Flaring

The aim of the CMM drainage and utilization project at Hebi Mine No. 6 is to use all of the drained CMM economically. But at many coal mines (especially those in remote locations far from possible energy markets, whose CMM produced volumes are relatively small, or have low concentrations of methane) CMM utilization is not technically or economically viable and the gas is vented directly to the atmosphere. This constitutes a safety hazard (potential build-up of flammable gas), a health hazard, and an environmental hazard (methane is over 21 times more potent than carbon dioxide as a greenhouse gas). Flaring CMM through a controlled flare system with redundant safety features can significantly reduce these hazards[2] and is briefly discussed here as a possible utilization method.

### 5.9.1 Benefits of Flaring

Gas flaring is a standard safety practice in many industries. For example, methane and other associated gases are routinely flared during processing and production of oil and gas, and are continuously flared from landfill collection systems. Coal mines incorporating a controlled flare system can minimize the potential of an unconfined deflagration occurring on the surface at the CMM discharge location, brought about by natural (lightning strikes) or man-made sources. This would mitigate risk to the public as well as the underground mine.

Continuous monitoring provisions, necessary with a CMM flare, can provide uninterrupted records of methane drainage performance. These can be valuable in comparing CMM production with underground conditions, and investigation of mine incidents such as mine fan failures, changes to the ventilation system, or accidents.

The destruction of methane through the flaring of CMM results in a considerable environmental benefit, compared to venting the CMM to the atmosphere. There is also a potential financial benefit to coal mine and CMM operators from revenues derived from the sale of carbon credits generated by the methane destruction.

### 5.9.2 Flare Design

Flare designs are divided between open and enclosed designs (Exhibit 5-16). Open flares are widely used at landfills, chemical plants, and refineries around the world. They have an advantage over enclosed flares in being simpler to design and install and requiring lower maintenance, therefore being lower cost. Some designs can be portable. But the visible flame associated with an open flare can cause local public objections, flameouts are possible in windy conditions and high methane destruction is not guaranteed or easily verified.

[2] This section excerpted from EPA online documentation: EPA, 1999. "Conceptual design for a coal mine gob well flare"; EPA, 2000. "Benefits of an enclosed gob well flare design for underground coal mines".

Enclosed flares consist of a vertical, refractory lined, combustion chamber which obscures the flame from public view. Enclosing the flame reduces thermal radiation from the flare at ground level making it safe to work around. The enclosed design also reduces noise associated with the combustion process. Enclosed flare designs have reported methane destruction efficiencies of over 99% and can incorporate monitoring equipment to verify the destruction. To sell the generated carbon credits, a carbon credit purchaser may require this extra level of verification, which is much more difficult to obtain with an open flare.



**Exhibit 5-16: Enclosed and Open Flare Designs**

Both open and enclosed flares are designed with multiple redundant safety features. Protection is provided from all potential sources of ignition and from flashback or detonation occurring in the flare stack via an integrated passive safety system (flame arrestors, fluidic and liquid seals), an active positive pressure system (blower/exhauster) and a monitoring and control system with valve and equipment activation.

### 5.9.3 CMM Flare Use in China

Although flares are used at land-fill and oil and gas sites in China, the NDRC has not approved flaring of CMM. If the CMM has a methane concentration below 30%, they would prefer mines upgrade their drainage systems to increase concentrations and then use the CMM rather than flaring it. The NDRC has regulated that all CMM with methane concentrations greater than 30% must be utilized. The Energy Information Agency (EIA, 2009) believes this rule is actually counter-productive in many cases, because mine operators who do not have economic options of CMM use available to them dilute their drained CMM below 30% methane to avoid the cost of having to utilize it. The diluted CMM is then vented to the atmosphere. In such cases, it would be much better for mine safety and the environment if flaring of the CMM stream, regardless of methane concentration, was permitted.

## 5.10 Power Generation Using Ventilation Air Methane

This section assesses the technical viability of utilization technologies for ventilation air methane (VAM). There are several technologies to mitigate VAM emissions which generally fall into one of three categories (see Exhibit 5-17 for a summary of VAM utilization technology options). Early efforts focused on the use of VAM as combustion air for internal combustion engines or large boilers. The use of VAM as a supplemental fuel for internal combustion engines was pioneered in Australia at the Appin Colliery in New South Wales, Australia, in 1996. The application of VAM as supplemental fuel for large utility or industrial boilers was demonstrated at the Vales Point Power Station, also in Australia. More recently, EESTech Inc. is pursuing the commercialization of a rotary kiln system that burns VAM with waste coal. The technology, originally developed by Australia's CSIRO and licensed by EESTech, uses the exhaust gas to power a turbine to produce electricity (Somers and Schultz, 2010).

The second category VAM utilization technologies fall into is lean-fuel turbines. Lean-fuel turbine systems supplement VAM with drained CMM to power specially designed turbines to produce electricity. Lean-fuel turbine systems such as CSIRO's VAMCAT™ and FlexEnergy's Flex-Microturbine ™ can run on VAM concentrations in the 1% to 1.5% range. Commercial scale application of lean-fuel turbines to mitigate VAM emissions has not yet been attempted. However, both technology vendors have demonstration projects planned. According to Somers and Schultz (2010), testing of a 30 kW VAMCAT™ unit at the Panyi Mine in China is planned while a 100 kW Flex-Microturbine™ prototype began testing at a landfill-gas-to-energy facility in February of 2010.

The third and only commercially-proven VAM mitigation technology falls into the category of flow reversal oxidizers. Thermal and catalytic flow reversal reactors (TFRR and CFRR, respectively) mitigate VAM emissions by heating the methane in VAM beyond its self-combustion temperature. In the process, methane in the VAM reacts with oxygen to form carbon dioxide and water, while generating heat. As VAM enters an oxidation unit, it passes through warm beds, causing its temperature to increase up to the desired oxidation temperature. The VAM stream then passes through the combustion chamber (if present), where the reaction takes place and the energy from the VAM is released. After complete oxidation, the stream passes through a second bed (or the second portion of the bed if there is only one) that absorbs most of the heat contained in the stream. A series of valves and dampers are cycled every few minutes to reverse the direction of the air flow through the oxidizer unit. Therefore, each bed is alternatively used to heat the incoming gases or recover heat from the oxidized gas (or in the case of a single bed system, each half of the bed). This process serves as a highly efficient heat recovery system, which allows an oxidizer to oxidize very low concentration waste streams with little or no need for supplemental fuel.

| VAM Technology Name | Classification | Vendor | Capacity | Minimum VAM Concentration Requirement (%) | Methane Removal Efficiency (%) | Deployment Status | Highlights |
|---|---|---|---|---|---|---|---|
| Combustion air in IC engines | Supplemental Fuel | NA | Unknown | Unknown | Unknown | Ongoing commercial VAM/CMM project in Australia | Appin Colliery in New South Wales, Australia: 54 VAM/CMM driven IC engines producing 55.6 MW of electricity |
| Combustion air in large boilers | Supplemental Fuel | NA | Unknown | Unknown | Unknown | Pilot/demonstration at power station | Vales Point Power Station in Australia: VAM as combustion air in boiler |
| EESTech HCGT | Supplemental Fuel | EESTech / CSIRO | 5-30 MW power output | TBD | TBD | Unknown; currently seeking to commercialize the technology in China and India | Rotary kiln system that burns waste coal with VAM; exhaust gas pases through air-to-air heat exchanger; hot air then powers turbine to produce electricity |
| Flex-Microturbine™ | Lean-fuel Turbine | FlexEnergy | 6,243 $m^3$/h (3,674 scfm) for 250 kW unit | 3 to 5 | 99 (target) | Pilot/demonstration at landfill | 100 kW prototype sent to landfill-gas-to-energy project in February of 2010; smallest production model will be 250 kW |
| VAMCAT™ | Lean-fuel Turbine | CSIRO | TBD | 1 | TBD | Unknown | 30 kW demonstration unit to be tested at the Huainan Mining Group's Panyi Mine in China |
| VOCSIDIZER™ | TFRR | MEGTEC Systems | 125,000 $m^3$/h (73,575 scfm) | 0.2 | 97 | History of industrial VOC control applications; ongoing commercial VAM oxidation project in Australia | Available in standardized units (125,000 m3/h); First demonstrated at British Coal's Thoresby Mine in the UK in 1994; Demonstration at Appin Colliery in 2001-2002 included heat recovery subsystem; Full-scale VAM-to-electricty project (WestVAMP) at BHB Billiton's West Cliff Colliery in Australia operational in April of 2007 and generates 6 MW of electrical power for the mine; Demonstration project at CONSOL Energy's Windsow Mine (abandoned) in West Virginia in 2007-2008 |
| VAMOX™ | TFRR | Biothermica | up to 169,920 $m^3$/h (100,000 scfm) | 0.2 | 98 | History of industrial VOC control applications; ongoing VAM oxidation project in US | Each unit customized to meet site-specific conditions; Small-scale commercial project at JWR's Mine No. 7 (active) in Alabama began in January of 2009; First VAM oxidizer to operate at an active mine in the Americas; First VAM oxidizer to receive MSHA approval |
| Ecopure® RL | TFRR | Durr Systems | 6,287-101,952 $m^3$/h (3,700-60,000 scfm) | 0.2 | 99 | History of industrial VOC control applications | Unique rotary oxidizer design; Proven in industrial applications but has yet to be field-tested in VAM-oxidation applications |
| GCE $CH_4$ Model | TFRR | Gulf Coast Environmental (GCE) | 84,960 $m^3$/h (50,000 scfm) | 0.25 | 95 | History of industrial VOC control applications | Single valve design minimizes pressure drop in the system; Includes hot gas bypass |
| $CH_4$MIN | CFRR | CANMET | 900 $m^3$/h (530 scfm) | 0.15 | 95 | Laboratory testing using natural gas; Currently in the process of being commercialized by SCS Americas | Catalysts in heat exchange medium allow oxidation reaction to occur at lower temperatures; Pilot-tested but has yet to be field-tested in VAM-oxidation applications |
| Sheng Dong Oxidizer | TFRR | Sheng Dong Group | 60,000 $m^3$/h (35,316 scfm) | 0.25 | 95 | Industrial VOC installation in China | Received Chinese patent in May of 2007; traditional TFRR design |

Source: Modified from Somers and Schultz (2010)

**Exhibit 5-17: VAM Utilization Technology Options**

Flow reversal oxidizers can be used solely to abate VAM emissions or, if energy recovery is desired, a dedicated heat exchanger which generates steam can be located in the bed, oxidation chamber or stack. In this case, the captured heat can be used for thermal energy or to produce electricity.

As of 2010, only two flow reversal oxidizers have been proven in the field, while at least three others are being commercialized to abate VAM (Exhibit 5-17). The only TFRRs proven at coal mines are the VAMOX™ by Biothermica Technologies and the VOCSIDIZER™ by Megtec Systems. Although their configuration and performance characteristics are not identical, both of these technologies use the operation principle of regenerative thermal oxidation.

The following sections provide an assessment of the three end-use options available (i.e., abatement only, heat generation, and power generation) with the use of the commercially-proven flow reversal oxidizers on the market.

### 5.10.1 General Characteristics of Commercially-Proven VAM Oxidation Systems

Exhibit 5-18 presents the operational characteristics of the two commercially-proven VAM oxidation systems (official information provided by manufacturers) and the figures used for the purpose of this study.

| Characteristic | VAMOX™ | VOCSIDIZER™ | Used for study |
|---|---|---|---|
| Number of beds | 2 | 1 | N/A |
| Min. methane content | 0.2% | 0.2% | 0.2% |
| Max. methane content | 1.2% (more if used with energy recovery system) | 0.8% (more if used with energy recovery system) | 1.2% |
| Typ. destruction efficiency | 96% | 96% | 96% |
| Unit capacity | 100,000 cfm | 65,000 cfm | as required |
| Operating temperature | 1,000°C | 1,000°C | 1,000°C |
| Start-up heater | propane burner | electrical heater | propane burner |
| NOx emissions | negligible | negligible | negligible |

**Exhibit 5-18: VAM Oxidation Systems Characteristics**

<u>VAM Capture Efficiency</u>: For the purpose of this study, it is assumed that the ducting from the oxidizer unit which captures ventilation air will not be physically connected to the mine shaft ventilation exhaust duct and that the capture efficiency will be 60% of the available VAM air flows. This conservative assumption is motivated by safety considerations to prevent any impact on the operation of the mine ventilation system.

### 5.10.2 Assessment of End-Use Options

To assess the technical viability of the technologies being considered, an evaluation of three VAM utilization scenarios was performed. The VAM utilization scenarios included (1) abatement only, (2) heat generation, and (3) power generation. For each scenario, the goal was to evaluate and/or provide a high level process flow diagram (PFD), a list of major system components and key characteristics, estimated capex and opex using a rule of thumb approach, estimated revenue, and basic financial investment analysis.

## Assumptions

Methane Content: The methane content in the Ventilation Air for December 2006 and June 2007 are shown respectively in Exhibit 5-19 and Exhibit 5-20. The average values for both months are shown in Exhibit 5-21.

| **Sources** | CH4 Concentration (%) | CH4 Emissions ($m^3$/day) | VAM Flow Rate ($m^3$/sec) | VAM Flow Rate (cfm) |
|---|---|---|---|---|
| Central Vent Shaft | 0.04 | 765 | 22.1 | 46,896 |
| Xiaozhuang Vent Shaft | 0.16 | 11,803 | 85.4 | 180,887 |
| East Wing Vent Shaft | 0.36 | 47,268 | 152.0 | 321,959 |
| | **Total** | **59,836** | **259.5** | **549,742** |

**Exhibit 5-19: Average Values for December 2006**

| **Sources** | CH4 Concentration (%) | CH4 Emissions ($m^3$/day) | VAM Flow Rate ($m^3$/sec) | VAM Flow Rate (cfm) |
|---|---|---|---|---|
| Central Vent Shaft | 0.10 | 1,669 | 19.3 | 40,925 |
| Xiaozhuang Vent Shaft | 0.26 | 20,292 | 90.3 | 191,376 |
| East Wing Vent Shaft | 0.42 | 54,801 | 151.0 | 319,944 |
| | **Total** | **76,762** | **260.7** | **552,245** |

**Exhibit 5-20: Average Values for June 2007**

| **Sources** | CH4 Concentration (%) | CH4 Emissions ($m^3$/day) | VAM Flow Rate ($m^3$/sec) | VAM Flow Rate (cfm) |
|---|---|---|---|---|
| Central Vent Shaft | 0.07 | 1,217 | 20.1 | 42,631 |
| Xiaozhuang Vent Shaft | 0.21 | 16,048 | 88.4 | 187,380 |
| East Wing Vent Shaft | 0.39 | 51,035 | 151.5 | 320,874 |
| | **Total** | **68,299** | **260.0** | **550,874** |

**Exhibit 5-21: Average of December 2006 and June 2007**

Methane also comes from an underground drainage system (Exhibit 5-22). This methane is transported to the surface vacuum station using an underground pipeline network. The entrained water content is separated from the gas gathering system at the surface by expanding the gas into separators. The surface vacuum station is equipped with two (2) liquid ring vacuum pumps, each with a capacity of 288,000 $m^3$/day of drained gas at a vacuum pressure of 16 kPa.

| | $CH_4$ Concentration (%) | $CH_4$ Emissions ($m^3$/day) | Drainage Flow Rate (air + $CH_4$) ($m^3$/sec) |
|---|---|---|---|
| December 2006 | 20 | 17,280 | 1.00 |
| June 2007 | 18 | 20,160 | 1.30 |
| Average | 18.9 | 18,720 | 1.15 |

**Exhibit 5-22: Methane Content at the Surface Vacuum Station**

20% of this drained gas is available for use and shall be considered dry at delivery. This equates to 487 cfm of gas with a methane level of 18.9%.

Additional Information / Assumptions: The applicable purchase or selling cost of electricity is 7.31 US¢/kWh. The selling price of one (1) $tCO_2e$ is assumed to be 15.00 US$.

Since no further information regarding the mine and the fan sites is available, the following assumptions have been used for the purpose of this study:

1. VAM air flow rates and methane concentration, as well as available drained gas figures, will not change significantly from the averages figures presented above over the project evaluation period.
2. The area around the fan house is assumed flat and unconstrained;
3. Each fan site is located 1 km from the surface vacuum station;
4. Selling price for heat generation is assumed to be 1.5 $/GJ;
5. Electricity generated by the project is not sold to the grid but used captively to minimize demand.
6. Compressed air supply is currently not available at fan sites;
7. Temperature of VAM is assumed to be similar to drained gas at average of 15.5ºC;
8. Natural gas or propane are currently not available at fan sites;
9. Available electrical power capacity (kW) is assumed sufficient to meet project demand at fan sites (no need to install additional transformers or power lines);
10. Unlimited need for thermal energy in the vicinity of the fan sites is assumed to be present (ex.: heating living quarters, coal preparation process, etc.);
11. Water supply for steam generation is assumed available at fan sites;
12. Facility availability rate of 95% (8,322 hrs/year)
13. Emission factor for consumed electricity: 1.25 $tCO_2e$/MWh;
14. Project development and registration costs are not considered;
15. Carbon credits verification, issuance and selling fees are not considered;
16. Electrical grid interconnection costs are not considered.

### 5.10.3 Methodology

Sizing & Process Selection: For each scenario, the inlet parameters of the system were identified based on the information provided by HECG. Equipment requirements were also identified, of which a general description is provided for the most significant components.

Capex and Opex Estimations: For each scenario, the capital expenditure (capex) and operational expenditure (opex) have been estimated based on published information and discussions with one of the major oxidizer suppliers.

A typical inflation rate of 2%/year has been applied to operation expenses over the life of the projects.

Revenues Estimations: The revenues generated under each scenario can come from 3 different sources:

1. Sale of carbon credits generated by the project activity;
2. If applicable, sale of excess heat generated by the system and recovered as steam;
3. If applicable, sale of excess electricity if the power produced by the project exceed the system's own demand.

Revenues remain constant over the life of the projects.

The calculation of the carbon credits generation was performed in accordance with UNFCCC's pertinent consolidated CDM methodology ref. ACM0008. The energy required to pre-heat the system was neglected in this calculation.

Financial Analysis: Cash flow tables have been generated for each scenario over a period of 20 years after project implementation.

In addition, the following parameters were calculated:

- Earning before interests, taxes, depreciation and amortization (EBITDA);
- Payback period
- Internal rate of return (IRR) over 15 years
- Internal rate of return (IRR) over 20 years

### 5.10.4 Abatement of Methane Only

Process Information and Equipment Sizing: Since the methane level in the VAM is below the maximum allowable figure of the oxidizer unit, and to improve the profitability of these projects, the use of the available drained gas by injection into the oxidizer unit has been considered. To allow assessing the potential of each shaft independently, both scenarios (VAM only and VAM + gas injection) have been analyzed for each vent shaft.

Injecting drained gas requires additional equipment like detonator arresters, pressure regulators, valves for security purposes on the drained gas line from the surface vacuum station facility. Additional methane analyzing capabilities are also required to measure the methane concentration in order to compile the methane entering the oxidation unit.

The VAM + drained gas Injection scenarios (A4, A5 and A6) are based on an incoming stream composed of a blend of VAM and drained gas from the surface vacuum station. For each scenario, 20% of the available drained gas (as shown in Exhibit 5-24) is considered to be injected in the incoming VAM flow.

| | Vent Shaft | | |
|---|---|---|---|
| | Central | Xiaozhuang | East Wing |
| **Scenario ref.** | **A1** | **A2** | **A3** |
| VAM flow rate | 20.1 m³/sec (42,600 cfm) | 88.4 m³/sec (187,309 cfm) | 151.5 m³/sec (321,010 cfm) |
| VAM CH4 level | 0.07% | 0.21% | 0.39% |
| Captured VAM flow rate | N/A | 112,300 cfm | 192,818 cfm |
| Electric consumption | N/A | 286 kW | 541 kW |

**Exhibit 5-23: Process Information for Methane Abatement (VAM Only)**

Scenario ref. A1 is not possible because the CH4 level is below the minimum design requirement.

| | Vent Shaft | | |
|---|---|---|---|
| | Central | Xiaozhuang | East Wing |
| **Scenario ref.** | **A4** | **A5** | **A6** |
| VAM flow rate | 20.1 m³/sec (42,600 cfm) | 88.4 m³/sec (187,309 cfm) | 151.5 m³/sec (321,010 cfm) |
| VAM CH4 level | 0.07% | 0.21% | 0.39% |
| Inlet flow rate (VAM + drained gas) | 43,220 cfm | 113,350 cfm | 193,300 cfm |
| VAM + drained gas $CH_4$ level | 0.28% | 0.29% | 0.44% |
| Electric consumption | 138 kW | 320 kW | 530 kW |

**Exhibit 5-24: Process Information for Methane Abatement (VAM + Drained Gas Injection)**

The process flow diagram for both configurations is presented in Exhibit 5-25.

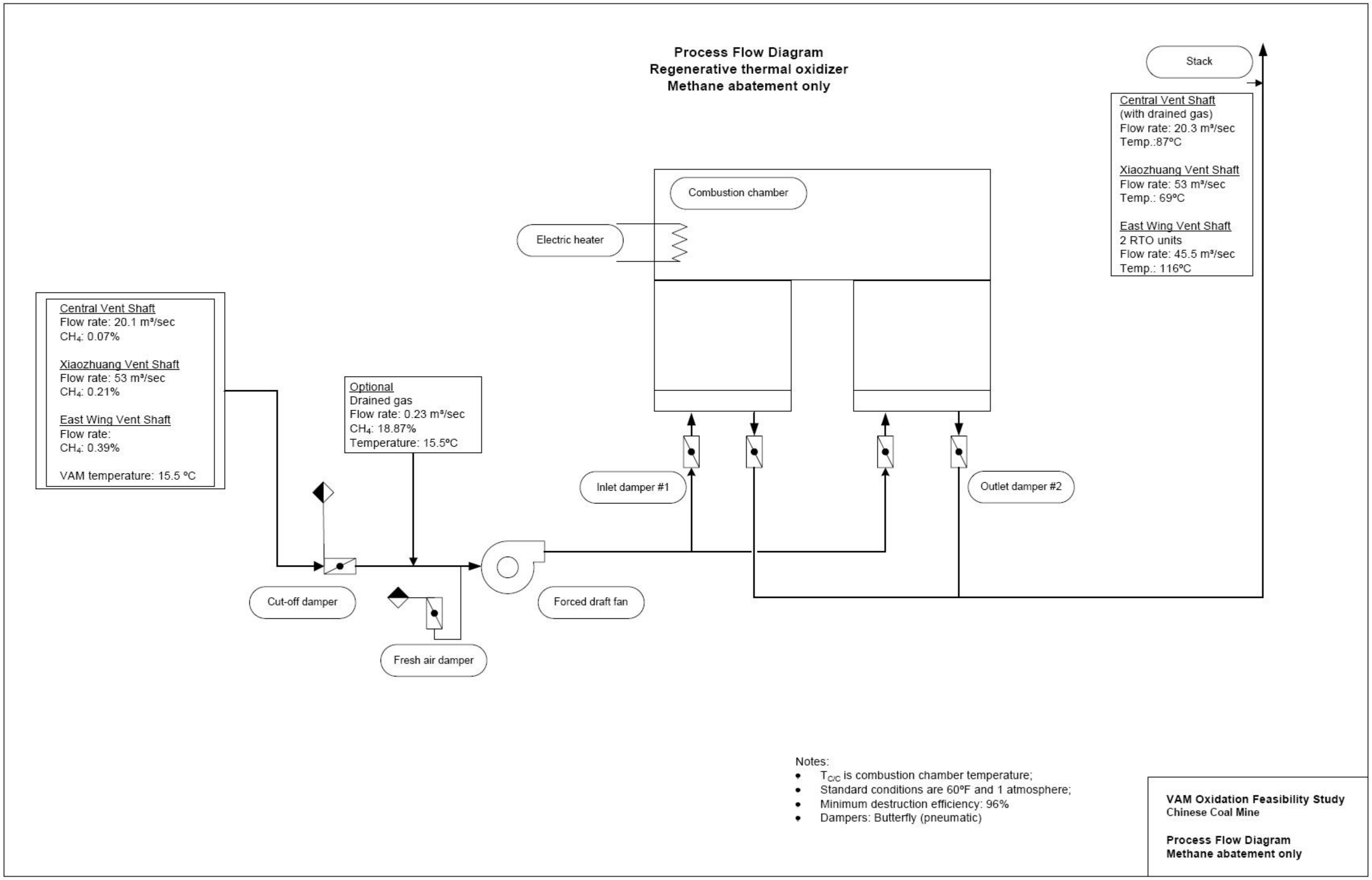


**Exhibit 5-25: Methane Abatement PFD**

Financial Estimations & Results: The financial information for the methane abatement only scenarios is presented in the table below. For more details, refer to Appendix 2.

| **Scenario ref.** | **A1** | **A2** | **A3** | **A4** | **A5** | **A6** |
|---|---|---|---|---|---|---|
| Carbon credits prod. ($tCO_2e$/year) | N/A | 36,644 | 120,706 | 18,895 | 51,895 | 137,374 |
| Capex ($US) | N/A | $3,269,000 | $6,395,000 | $1,955,000 | $3,319,000 | $6,445,000 |
| Opex ($US, year 1) | N/A | $283,985 | $450,111 | $191,951 | $304,668 | $443,419 |
| Annual revenues ($US) | N/A | $549,664 | $1,810,596 | $283,427 | $778,429 | $2,060,608 |
| Payback period (years) | N/A | 16.0 | 5.1 | 38.9 | 8.1 | 4.2 |
| IRR (15 years period) | N/A | 0% | 19% | -9% | 10% | 24% |
| IRR (20 years period) | N/A | 3% | 20% | -8% | 12% | 24% |

**Exhibit 5-26: Financials for Methane Abatement Only Scenarios**

### 5.10.5 Heat Generation

Process Information and Equipment Sizing: Since the methane level in the VAM is below the maximum allowable figure of the oxidizer units and to improve the profitability of these projects, the use of the available drained gas by injection into the oxidizer has been considered. Because no information was provided regarding the location where this gas is available and to allow assessing the potential of each shaft independently, both scenarios (VAM only and VAM + gas injection) have been analyzed for each vent shaft.

Injecting drained gas requires additional equipment like detonator arresters, pressure regulators, valves for security purposes on the drained gas line from the surface vacuum station facility. Additional methane analyzing capabilities are also required to measure the methane concentration in order to compile the methane entering the oxidizer units.

By adding a heat exchanger on the outlet manifold of the oxidizer, it is possible to recover the heat of outlet gases and heat water. This water can be used to heat working areas for example. A default commercial value was used to calculate potential revenues from the use of this heat source. The selected heat exchanger is a cross-flow tube and shell exchanger. Typical efficiency is about 70%. Water flow can be adjusted or stopped to meet local demand. We considered that the water feed to the heat generation system is at a temperature of 10 ºC.

The process flow diagram for heat generation is shown in Exhibit 5-27.

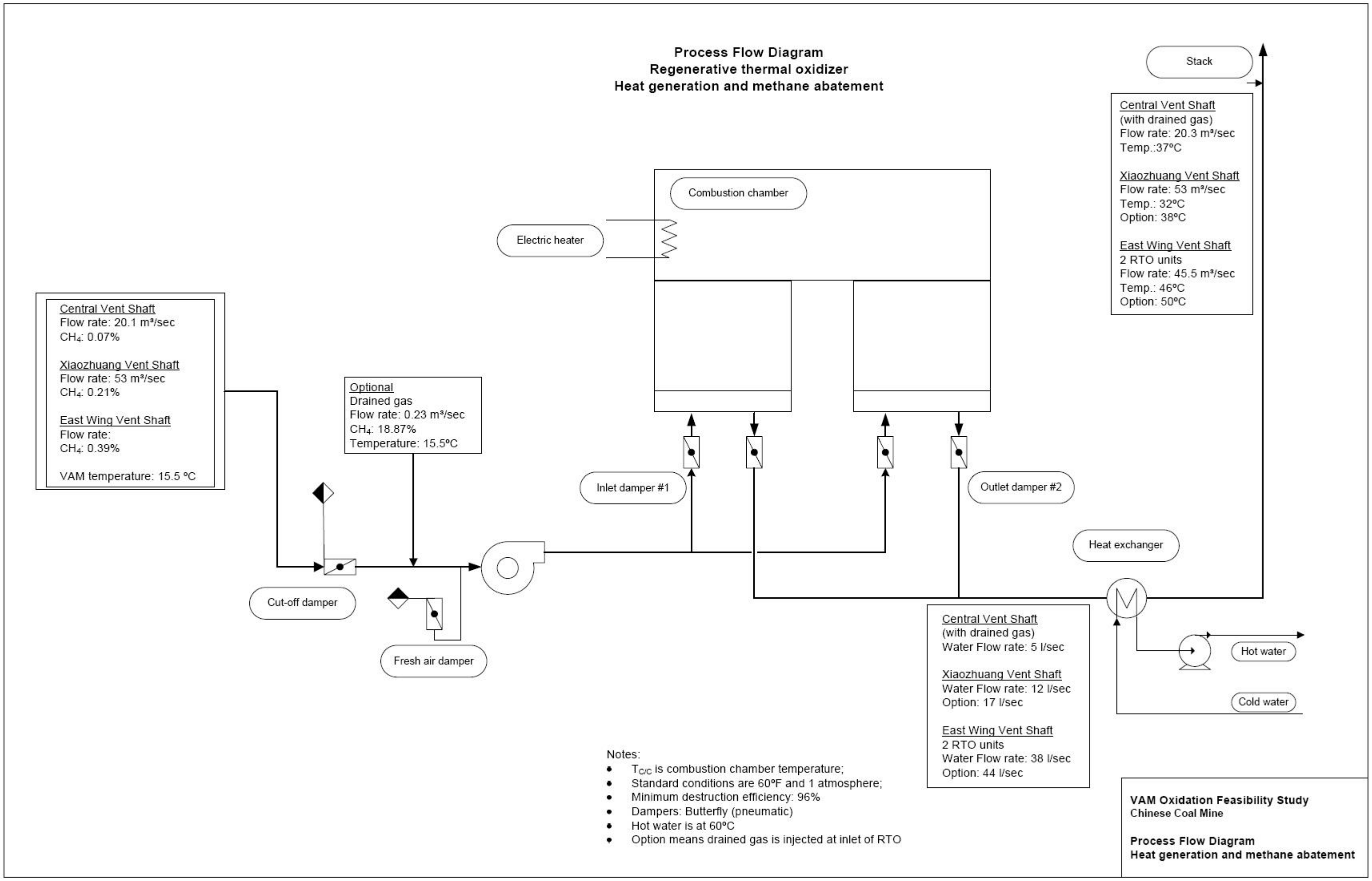


**Exhibit 5-27: Heat Generation PFD**

System Main Components and Characteristics: The components and characteristics for the oxidizer are the same as in the "abatement of methane only" scenarios, with the addition of a heat exchanger, water pumps, valves, pipes and instrumentation.

- *Heat exchanger:* The heat exchanger is composed of multiple parallel pipes installed in the outlet duct/stack. A thermal recovery efficiency of 70% was used.
- *Water circulation pumps:* Two centrifugal circulation pumps are required; one is in operation, one as a back-up. Valves allow their isolation for maintenance purposes.
- *Expansion tank:* A water tank is required to allow for the expansion of water as a result of temperature differences. It also acts as a buffer tank and maintains an adequate water level in the system.

| | Vent Shaft | | |
|---|---|---|---|
| | Central | Xiaozhuang | East Wing |
| **Scenario ref.** | **H1** | **H2** | **H3** |
| VAM CH4 level | 0.07% | 0.21% | 0.39% |
| Captured VAM flow rate | N/A | 112,300 cfm | 192,818 cfm |
| Heat content in outlet flue gas (kW) | N/A | 3 504 | 11 390 |
| Recovered heat (GJ/hr) | N/A | 9 | 28 |
| Outlet water temperature (ºC) | N/A | 60 | 60 |
| Flow of water (l/sec) | N/A | 12 | 38 |

**Exhibit 5-28: Process Requirements for Heat Generation (VAM Only)**

Because of the low concentration of methane in scenario H1, the process is not viable and this scenario was not considered.

The VAM + drained gas Injection scenarios (H4, H5 and H6) are based on an incoming stream composed of a blend of VAM and drained gas from the surface vacuum station. For each scenario, 20% of the available drained gas (Exhibit 5-22) is considered to be injected in the incoming VAM flow.

| | Vent Shaft | | |
|---|---|---|---|
| | Central | Xiaozhuang | East Wing |
| **Scenario ref.** | **H4** | **H5** | **H6** |
| Inlet flow rate (VAM + drained gas) | 43,220 cfm | 113,350 cfm | 193,300 cfm |
| VAM + drained gas CH4 level | 0.28% | 0.29% | 0.44% |
| Heat content in outlet flue gas (kW) | 1,799 | 4,918 | 12,810 |
| Recovered heat (GJ/hr) | 5 | 12 | 32 |
| Outlet water temperature (ºC) | 60 | 60 | 60 |
| Flow of water (l/sec) | 6 | 17 | 44 |

**Exhibit 5-29: Process Requirements For Heat Generation (VAM + Drained Gas Injection)**

Financial Estimations & Results: The financial results for the heat generation scenarios are presented in Exhibit 5-30.

| **Scenario ref.** | **H1** | **H2** | **H3** | **H4** | **H5** | **H6** |
|---|---|---|---|---|---|---|
| Carbon credits prod. (tCO2e/year) | N/A | 36,540 | 120,374 | 18,843 | 51,750 | 136,999 |
| Heat prod. (GJ/h) | N/A | 9.0 | 28.0 | 5.0 | 12.0 | 32.0 |
| Capex ($US) | N/A | $3,334,000 | $6,525,000 | $2,005,000 | $3,399,000 | $6,575,000 |
| Opex ($US, year 1) | N/A | $308,068 | $508,578 | $209,992 | $333,185 | $507,319 |
| Annual revenues ($US) | N/A | $660,451 | $2,155,127 | $345,062 | $926,040 | $2,454,446 |
| Payback period (years) | N/A | 11.6 | 4.2 | 22.3 | 6.5 | 3.6 |
| IRR (15 years period) | N/A | 5% | 24% | -3% | 14% | 28% |
| IRR (20 years period) | N/A | 6% | 24% | -1% | 15% | 29% |

**Exhibit 5-30: Financials for Heat Generation Scenarios**

### 5.10.6 Power Generation

Process Information and Equipment Sizing: As in the previous sections, the use of the available drained gas has been considered. Because no information was provided regarding the location where this gas is available and to allow assessing the potential of each shaft independently, both scenarios (VAM only and VAM + gas injection) have been analyzed for each vent shaft.

Again, injecting drained gas requires additional equipment as described in the previous sections. The power generation system is based on the oxidizer unit coupled with commercially available small scale steam generators and turbines. A steam generation system adapted for the capture of excess heat from the oxidation of the methane directly in the oxidation chamber of the oxidizer. The steam then drives a single stage steam turbine which produces electricity. After the steam turbine, the low pressure steam goes into a condenser where it changes phase into water and is returned by the pump to the steam generation system (closed loop system).

The electricity is to be used by the mine and any excess is to be sold on the grid.

For sizing purposes, the steam is generated at a pressure between 2,500 and 2,650 kPa and at a temperature of 370 ºC. The following figures are based on a turbine heat rate of 13,715 kJ/kWh.

The process flow diagram for power generation is shown in Exhibit 5-31.

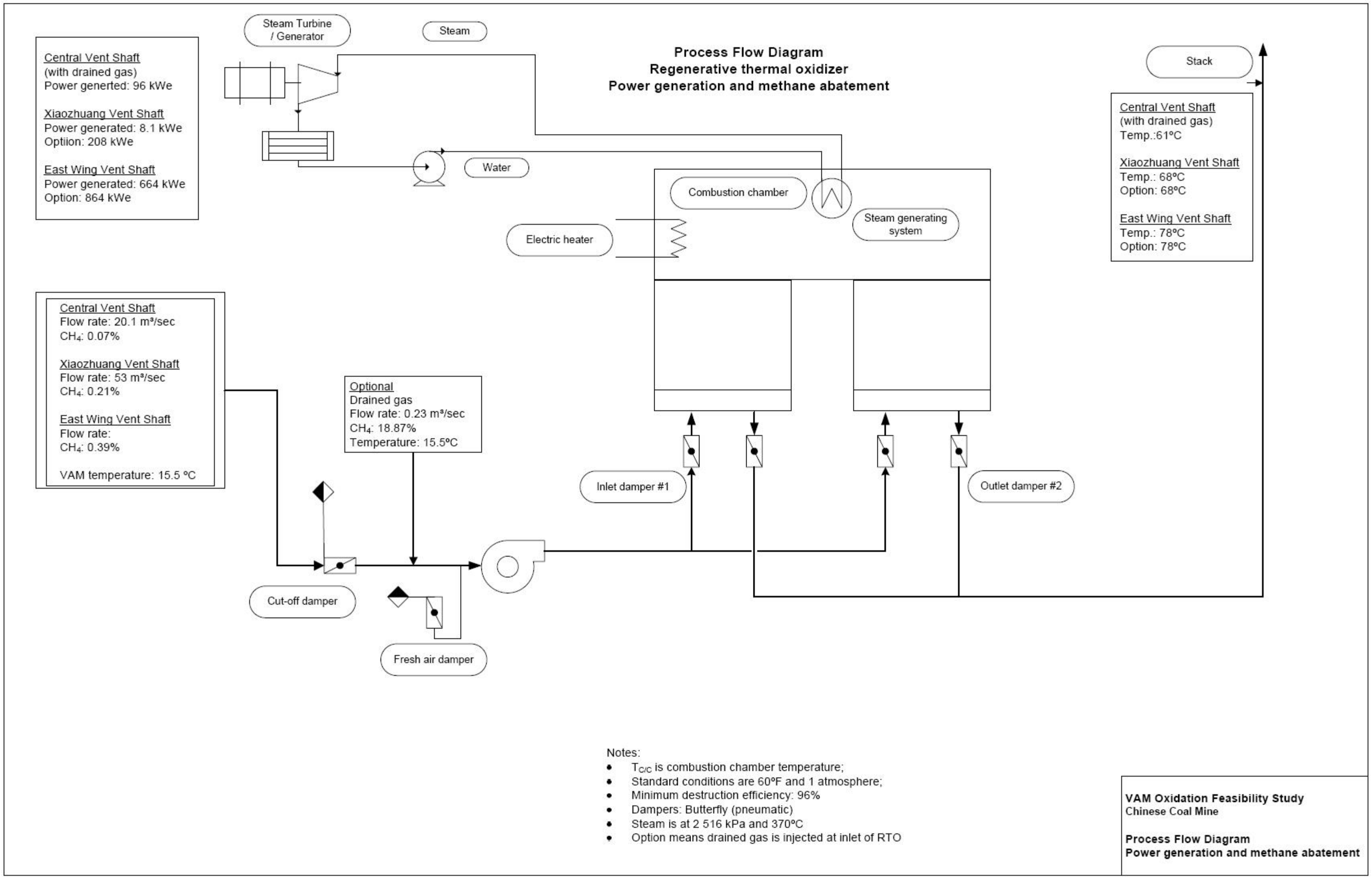


**Exhibit 5-31: Power Generation PFD**

System Main Components and Characteristics:

- *Steam turbine/generator set:* The steam turbine is of the single valve, single stage condensing type. It is complete with the generator and all required controls. It is supplied with an HMI interface for control, a complete system monitoring. The steam turbine set is skid mounted. The generator is supplied with an integrated circuit breaker and the power generation is optimized with the available steam.
- *Condenser:* The condenser is used to collect the condensed water exiting the steam turbine. A pump transfers the water to the steam generating tubes.

Scenarios E1 and E2 (Exhibit 5-32) are not applicable because the methane concentration is too low for the system to operate satisfactorily.

| | Vent Shaft | | |
|---|---|---|---|
| | Central | Xiaozhuang | East Wing |
| **Scenario ref.** | **E1** | **E2** | **E3** |
| VAM CH4 level | 0.07% | 0.21% | 0.39% |
| Captured VAM flow rate | N/A | N/A | 192,818 cfm |
| Available heat from CH4 (kWTH) | N/A | N/A | 4,636 |
| Electrical power generated (kWE) | N/A | N/A | 664 |

**Exhibit 5-32: Process Requirements for Power Generation (VAM Only)**

The VAM + drained gas Injection scenarios - E4, E5 and E6 (Exhibit 5-33) - are based on an incoming stream composed of a blend of VAM and drained gas from the surface vacuum station. For each scenario, 20% of the available drained gas (Exhibit 5-22) is considered to be injected in the incoming VAM flow.

| | Vent Shaft | | |
|---|---|---|---|
| | Central | Xiaozhuang | East Wing |
| **Scenario ref.** | **E4** | **E5** | **E6** |
| Inlet flow rate (VAM + drained gas) | 43,220 cfm | 113,350 cfm | 193,300 cfm |
| VAM + drained gas CH4 level | 0.28% | 0.29% | 0.44% |
| Available heat from CH4 (kWTH) | 673 | 1,380 | 6,034 |
| Electrical power generated (kWE) | 96 | 208 | 864 |

**Exhibit 5-33: Process Requirements for Power Generation (VAM + Drained Gas Injection)**

Financial Estimations & Results: The financial results for the electricity generation scenarios are presented in the table below.

| **Scenario ref.** | **E1** | **E2** | **E3** | **E4** | **E5** | **E6** |
|---|---|---|---|---|---|---|
| Carbon credits prod. (tCO2e/year) | N/A | N/A | 127,156 | 19,717 | 53,705 | 145,841 |
| Net Elect. Prod. (kW) | N/A | N/A | 79 | 0 | 0 | 284 |
| Capex ($US) | N/A | N/A | $7,685,000 | $2,348,000 | $3,874,000 | $8,065,000 |
| Opex ($US, year 1) | N/A | N/A | $283,000 | $266,892 | $340,817 | $301,000 |
| Annual revenues ($US) | N/A | N/A | $1,955,398 | $295,754 | $805,579 | $2,360,390 |
| Payback period (years) | N/A | N/A | 4,8 | N/A* | 9.9 | 4.0 |
| IRR (15 years period) | N/A | N/A | 20% | N/A | 7% | 24% |
| IRR (20 years period) | N/A | N/A | 21% | N/A | 9% | 25% |

**Exhibit 5-34: Financials for Electricity Generation Scenarios**

### 5.10.7 Recommendations for Ventilation Air Methane Utilization

A summary of the financial results of all the scenarios considered for VAM utilization at Hebi Mine No.6 is shown in Exhibit 5-35.

Considering as acceptable a payback of approximately five years and an IRR above 15%, the following scenarios emerge as interesting: Scenarios A3, A6, H3, H6, E3 and E6. These scenarios all use the VAM output of the East Wing Vent Shaft, which has the highest methane concentration and flow rate of the three vent shafts.

The scenario with the best financial outlook is H6 “heat production with drained gas” from the East Wing Vent Shaft with a payback of 3.6 years and an IRR of 28% over 15 years and 29% over 20 years. As a result, Scenario H6 is the recommended approach for VAM utilization at Mine No. 6.

| | Scenario | Payback Period (Years) | IRR (15 years) |
|---|---|---|---|
| Methane abatement of VAM – Central Vent Shaft | A1 | N/A | N/A |
| Methane abatement of VAM – Xiaozhuang Vent Shaft | A2 | 16 | 0 |
| Methane abatement of VAM - East Wing Vent Shaft | A3 | 5.1 | 19 |
| Methane abatement of VAM & Drained Gas – Central Vent Shaft | A4 | 38.9 | -9% |
| Methane abatement of VAM & Drained Gas – Xiaozhuang Vent Shaft | A5 | 8.1 | 10% |
| Methane abatement of VAM & Drained Gas - East Wing Vent Shaft | A6 | 4.2 | 24% |
| VAM – Combusted to heat water – Central Vent Shaft | H1 | N/A | N/A |
| VAM – Combusted to heat water – Xiaozhuang Vent Shaft | H2 | 11.6 | 5% |
| VAM – Combusted to heat water - East Wing Vent Shaft | H3 | 4.2 | 24% |
| VAM & Drained Gas – Combusted to heat water – Central Vent Shaft | H4 | 22.3 | -3% |
| VAM & Drained Gas – Combusted to heat water – Xiaozhuang Vent Shaft | H5 | 6.5 | 14% |
| VAM & Drained Gas – Combusted to heat water - East Wing Vent Shaft | H6 | 3.6 | 28% |
| VAM – Combusted to generate electricity – Central Vent Shaft | E1 | N/A | N/A |
| VAM – Combusted to generate electricity – Xiaozhuang Vent Shaft | E2 | N/A | N/A |
| VAM – Combusted to generate electricity - East Wing Vent Shaft | E3 | 4.8 | 20% |
| VAM & Drained Gas – Combusted to generate electricity – Central Vent Shaft | E4 | N/A | N/A |
| VAM & Drained Gas – Combusted to generate electricity – Xiaozhuang Vent Shaft | E5 | 9.9 | 7% |
| VAM & Drained Gas – Combusted to generate electricity - East Wing Vent Shaft | E6 | 4 | 24% |

**Exhibit 5-35: Summary of Financial Results for VAM Use Options**

## 5.11 Appendices

### 5.11.1 Caterpillar CMM Gas Engine

**Coal Mine Methane Gas**

**CATERPILLAR**

Image shown may not reflect actual package

**Continuous**
**1966 ekW 2458 kVA**
**50 Hz 1500 rpm**
**400 Volts**

Caterpillar® is leading the power generation market place with Power Solutions engineered to deliver unmatched flexibility, expandability, reliability, and cost-effectiveness.

**FEATURES**

**EMISSIONS**
- Meets most worldwide emissions requirements down to 250 mg / $Nm^3$ $No_x$ level without after-treatment.

**FULL RANGE OF ATTACHMENTS**
- Wide range of bolt-on system expansion attachments, factory designed and tested
- Flexible packaging options for easy and cost effective installation

**WORLDWIDE PRODUCT SUPPORT**
- Caterpillar dealers have over 1,600 dealer branch stores operating in 200 countries.
- Comprehensive post-sales support including maintenance and repair agreements that a re-tailored to your specific equipment application.
- High skilled technicians are trained to service every aspect of your electric power generation system.
- The Cat® SOS^sm Service monitors and tracks internal engine component condition providing the capability to maximize product performance and minimizing owning and operating costs.

**CAT® G3520C CMM GAS ENGINE**
- Robust high speed block design provides prolonged life and lower owning and operating costs.
- Designed for maximum performance on low pressure gas fuel supply
- Simple open chamber combustion system for reliability and fuel flexibility
- Leading edge technology in ignition system and air/fuel ratio control for lower emission and engine efficiency.
- One electronic control module handles all engine functions: ignition, governing, air/fuel ratio control and engine protection

**CAT® SR4B GENERATOR**
- Designed to match performance and output characteristics of Caterpillar gas engines
- Industry leading mechanical and electrical design
- High efficiency

**CAT EMCP II+ CONTROL PANEL**
- Simple user friendly interface and navigation
- Digital monitoring, metering and protection setting
- Fully featured power metering and protective relaying
- Remote control and monitor capability options

## G3520C Generator Set 50 Hz, 1966 ekW 2458 kVA, Continuous

CATERPILLAR

### FACTORY INSTALLED STANDARD & OPTIONAL EQUIPMENT

| System | Standard | Optional |
|---|---|---|
| Gas Engine Control Module (GECM) | Fuel/air ratio control;<br>Start/stop logic: gas purge cycle, staged shutdown;<br>Engine Protection System: detonation sensitive timing, high exhaust temperature shutdown;<br>Governor: Transient richening and turbo bypass control;<br>Ignition | |
| Air Inlet | Two element, single-stage air cleaner with enclosure and service indicator | Air cleaner with precleaner; Mounting stand |
| Control Panel | EMCP II+ | Local alarm module; Remote annuciator;<br>Customer Communication Module (CCM);<br>Synchronizing module; Engine failure relay |
| Cooling | Engine driven water pumps for jacket water and aftercooler;<br>Jacket water and SCAC thermostats;<br>ANSI/DN customer flange connections for JW inlet and outlet<br>Cat flanges on SCAC circuit | Remote radiator for JW and SCAC circuits, level switch included but not wired, coolant level drain line with valves, fan with guard;<br>Inlet/Outlet connections. |
| Exhaust | Dry exhaust manifolds, insulated and shielded;<br>Center section cooled turbocharger with Cat flanged outlet;<br>Individual exhaust port and turbocharger outlet wired to Integrated Temperature Sensing Module (ITSM) with GECM providing alarms and shutdowns. | Flange; Exhaust expander; Elbow; Flexible fitting;<br>Muffler and spark-arresting muffler with companion flanges. |
| Fuel | Electronic fuel metering valve;<br>Throttle plate, 24V DC actuator, controlled by GECM;<br>Fuel system is sized for 10.8 to 35.6 MJ/NM3 dry gas with pressure of 10.2 to 34.5 kPa to the engine fuel control valve. | Fuel filter;<br>Gas pressure regulator;<br>Gas shutoff valve, 24V, ETR (Energized-To-Run) |
| Generator | SR4B generator, includes:<br>Caterpillar's Digital Voltage Regulator (CDVR) with 3-phase sensing and KVAR/PF control; Reactive droop;<br>Bus bar connections; Winding temperature detectors;<br>Anti-condensation space heater. | Medium and high voltage generators and attachments<br>Low voltage extension box; Cable access box;<br>Air filter for generator; Bearing temperature detectors;<br>Manual voltage control; European bus bar.<br>kW Transducers (shipped loose) |
| Governing | Electronic speed governor as part of GECM;<br>Electronically-controlled 24V DC actuator connected to throttle shaft. | Woodward load sharing module |
| Ignition | Electronic Ignition System controlled by GECM;<br>Individual cylinder Detonation Sensitive Timing (DST) | |
| Lubrication | Lubricating oil; Gear type lube oil pump; Oil filter, filler and dipstick<br>Integral lube oil cooler; Oil drain valve; Crankcase breather. | Oil level regualtor; Prelube pump;<br>Positive crankcase ventilation system |
| Mounting | 330 mm structural steel base (for low and medium voltage units);<br>Spring-type anti-vibration mounts (shipped loose) | |
| Starting / Charging | 24V starting motors; Battery with cables and rack (shipped loose);<br>Battery disconnect switch; | Charging alternator; Battery charger;<br>Oversized battery; Jacket water heater; |
| General | Paint -- Caterpillar Yellow except rails & radiators;<br>Damper guard.<br>Operation and Maintenance Manuals; Parts Book. | Crankcase explosion relief valve;<br>Engine barring group;<br>EEC D.O.I and other certifications |

# G3520C Generator Set 50 Hz, 1966 ekW 2458 kVA, Continuous

CATERPILLAR®

## SPECIFICATIONS

**CAT GAS ENGINE**

G3520C SCAC 4-stroke-cycle watercooled gas engine

| | |
|---|---|
| Number of Cylinders | V20 |
| Bore --- mm (in) | 170 (6.7) |
| Stroke --- mm (in) | 190 (7.5) |
| Displacement --- L (cu in) | 86 (5248) |
| Compression Ratio | 11.3:1 |
| Aspiration | Turbocharged Separate Circuit Aftercooled |
| Cooling Type | Two-stage aftercooler, JW + O/C + A/C 1 combined |
| Fuel System | Low Pressure |
| Governor Type | Electronic (ADEM™ III) |

**CAT SR4B GENERATOR**

| | |
|---|---|
| Frame size | 828 |
| Excitation | Permanent Magnet |
| Pitch | 0.7777 |
| Number of poles | 4 |
| Number of bearings | 2 |
| Number of leads | 6 |
| Insulation | Class H |
| IP rating | Drip proof IP22 |
| Alignment | Pilot shaft |
| Overspeed capability -- % of synchronous speed | 125% |
| Waveform deviation line to line, no load | less than 3.0% |
| Paralleling kit droop transformer | Standard |
| Voltage regulator | CDVR |
| Voltage regulation with 3% speed change | +/- 0.5% |
| Telephone Influence Factor (TIF) | less than 50 |

**Consult your Caterpillar dealer for available voltage**

**CAT EMCPII+ CONTROL PANAL**

* Power by 24 volts DC
* NEMA 12, IP44 dust-proof enclosure
* Lockable hinged door
* Single-location customer connection
* Auto start/stop control switch
* Voltage adjustment potentiomenter
* True RMS AC metering, 3 phase
* Pruge cycle and staged shutdown logic
* Digital indication for:
    RPM
    Operating hours
    Oil pressure
    Coolant temperature
    DC voltage
    L-L volts, L-N volts, phase amps, Hz, ekW, kVA, kVAR, kWhr, %kW, pf
    System diagnostic codes
* Shutdown with indicating lights;
    Low oil pressure
    High coolant temperature
    High oil temperature
    Overspeed
    Overcrank
    Emergency stop
    High inlet air temperature (for TA engine only)
    Detonation sensitive timing (for LE engine only)
* Programmable protective relaying functions:
    Under / Over voltage
    Under / Over frequency
    Overcurrent
    Reverse power
* Spare indicator LEDs
* Spare alarm/shutdown inputs

## G3520C Generator Set 50 Hz, 1966 ekW 2458 kVA, Continuous

CATERPILLAR®

### TECHNICAL DATA

| 50 Hz 1500 rpm 400 Volts | | DM 8631 | DM 8632 |
|---|---|---|---|
| **G3520C Coal Mine Methane Generator Set** | | | |
| Emission level (NOx) | mg/Nm$^3$ | 500 | 250 |
| Aftercooler SCAC (Stage 2) | Deg C | 54 | 54 |
| **Package Performance (1)** | | | |
| Power Rating @ 0.8 pf (w/ 2 water pumps and w/o fan) | kVA Continuous | 2458 | 2458 |
| Power Rating @ 0.8 pf (w/ 2 water pumps and w/o fan) | ekW Continuous | 1966 | 1966 |
| Power Rating @ 1.0 pf (w/ 2 water pumps and w/o fan) | ekW Continuous | 1988 | 1988 |
| Electric Efficiency @ 1.0 pf (ISO 3046/1) (5) | % | 40.4 | 39.6 |
| Mechanical Power (w/ 2 water pumps and w/o fan) | bkW | 2035 | 2035 |
| **Fuel Consumption (2)** | | | |
| 100% load w/o fan | Nm$^3$/hr | 900 | 906 |
| 75% load w/o fan | Nm$^3$/hr | 696 | 713 |
| 50% load w/o fan | Nm$^3$/hr | 490 | 502 |
| **Altitude Capability (3)** | M | | |
| At 25 Deg C (77 Deg F) ambient | (above Sea Level) | 1250 | 950 |
| **Cooling System** | | | |
| Ambient air temperature | Deg C | 25 | 25 |
| Jacket water temperature ( Maximum outlet ) | Deg C | 99 | 99 |
| **Exhaust System** | | | |
| Combustion air inlet flow rate | Nm$^3$/min | 137 | 141 |
| Exhaust stack gas temperature | Deg C | 472 | 469 |
| Exhaust gas flow rate | Nm$^3$/min | 153 | 157 |
| Exhaust flange size ( internal diameter ) | mm | 360 | 360 |
| **Heat Rejection (4)** | | | |
| Heat rejection to jacket water and oil cooler and AC - Sta | kW | 1030 | 1067 |
| Heat rejection to oil cooler and AC - Stage 2 | kW | 182 | 178 |
| Heat rejection to exhaust (LHV to 120$^0$C) | kW | 1264 | 1289 |
| Heat rejection to atmosphere from engine | kW | 138 | 138 |
| Heat rejection to atmosphere from generator | kW | 63 | 63 |
| **Generator** | | | |
| Frame | | 828 | 828 |
| Temperature rise | Deg C | 105 | 105 |
| Motor starting capability @ 30% voltage dip (6) | sKVA | 4557 | 4557 |
| **Lubrication System** | | | |
| Standard sump refill with filter change | L | 541 | 541 |
| **Emissions (7)** | | | |
| NOx @ 5% $O_2$ | mg/Nm$^3$ (dry) | 500 | 250 |
| CO @ 5% O2 | mg/Nm$^3$ (dry) | 1076 | 985 |
| THC @ 5% O2 | mg/Nm$^3$ (dry) | 2331 | 2505 |
| NMHC @ 5% O2 | mg/Nm$^3$ (dry) | 350 | 376 |
| Exhaust O2 (dry) | % (dry) | 9.4 | 9.7 |

## G3520C Generator Set 50 Hz, 1966 ekW 2458 kVA, Continuous

CATERPILLAR

### CONDITIONS AND DEFINITIONS

(1) **Continuous** --- Maximum output available without varying load for an unlimited time

**Ratings** are based on low energy methane-based gas having a Low Heat Value (LHV) of 19.7 MJ/NM3 (500 Btu/ft3) and 100 Caterpillar Methane Number.
For values in excess of altitude, ambient temperature, inlet/exhaust restriction, or different from the conditions listed, contact your local Caterpillar dealer.

**(2) Ratings and fuel consumption** are based on ISO3046/1 standard reference conditions of 25 deg C (77 deg F) of ambient temperature and 100 kPa (29.61 in Hg) of total barometric pressure with 0, +5% fuel tolerance.

(3) **Altitude** capability is based on 2.5 kPa inlet and 5.0 kPa exhaust restriction.

(4) **Heat Rejection** --- Values based on ISO3046/1 with fuel tolerance of +/-3% and 2.5 kPa inlet and 5.0kPa exhaust restriction.

(5) **Efficiency** of standard generator is used. For higher efficiency generators, contact your local Caterpillar dealer.

(6) **Assume** synchronous driver

(7) **Emissions data** measurements are consistent with those described in EPA CFR 40 Part 89 Subpart D & E and ISO8178-1 for measuring HC, CO, PM, $NO_x$. Data shown is based on steady state engine operating conditions of 25 deg C (77 deg F), 96.28 kPa (28.43 in Hg) and fuel having a LHV of 19.7 MJ/N.m3 (500 Btu/cu ft) at 101.60 kPa (30.00 in Hg) absolute and 0 deg C (32 deg F).
Emission data shown is subject to instrumentation, measurement, facility, and engine fuel system adjustment.

(8) **Nominal Value** --- Emissions from a new engine during first 100 hrs of operation.
Contact local Caterpillar dealer for more information.

| Package Dimensions | | |
|---|---|---|
| Length | 6316.0 mm | 248.66 in |
| Width | 1827.5 mm | 71.95 in |
| Height | 2564.8 mm | 100.98 in |
| Est. Shipping Weight | 18 350 kg | 40 437 lb |

### 5.11.2 GE Jenbacher CMM Engine

GE
Energy

# Jenbacher type 3


## efficient, durable, reliable

Long service intervals, maintenance-friendly engine design and low fuel consumption ensure maximum efficiency in our type 3 engines. Optimized components prolong service life even when using non-pipeline gases such as landfill gas. The type 3 stands out in its 500 to 1,100 kW power range due to its technical maturity and high degree of reliability.

## reference installations

| model, plant | key technical data | description | |
|---|---|---|---|
| J312 GS<br>**Containerized solution<br>Landfill site;<br>Cavenago, Italy** | Fuel ........ Landfill gas<br>Engine type ........ 3 x JMC 312 GS-L.L<br>Electrical output........ 1,803 kW<br>Thermal output........ 2,241 kW<br>Commissioning........ September 1999 | Every system has its own landfill gas feeder line and exhaust gas treatment line. The generated electricity is used on-site, excess power is fed into the public grid. The employment of the CL.AIR® system ensures the purification of the exhaust gas to meet stringent Italian emission requirements. As a special feature, at this plant the thermal energy is used for landfill leachate treatment, as well as for greenhouse heating. |  |
| J316 GS<br>**Profusa,<br>producer of coke;<br>Bilbao, Spain** | Fuel ........ Coke gas and natural gas<br>Engine type ........ 12 x JGS 316 GS-S/N.L<br>Electrical output<br>a) with 100% coke gas ........ 5,642 kW<br>b) with 60% coke gas and 40% natural gas,<br>or 100% natural gas........ 6,528 kW<br>Commissioning........ November 1995 | This installation designed by GE's Jenbacher product team enables Profusa to convert the residual coke gas with a hydrogen content of approximately 50% into valuable electrical energy. |  |
| J320 GS<br>**Ecoparc I;<br>Barcelona, Spain** | Fuel ........ Biogas and natural gas<br>Engine type ........ 5 x JMS 320 GS-B/N.L<br>Electrical output........ 5,240 kW<br>Thermal output<br>a) with biogas........ 2,960 kW<br>b) with natural gas........ 3,005 kW<br>Commissioning........ December 2001<br>to January 2002 | In Ecoparc I, organic waste is processed into biogas, which serves as energy source for our gas engines. The generated electricity is used on-site as well as fed into the public power grid. A portion of the thermal energy is used as process heat in the digesters, and the excess heat is bled off in the air coolers. |  |
| J320 GS<br>**Amtex Spinning Mills;<br>Faisalabad, Pakistan** | Fuel ........ Natural gas<br>Engine type ........ 4 x JGS 320 GS-N.L<br>Electrical output........ 4,024 kW<br>Commissioning........ November 2002,<br>May 2003 | The natural gas-driven units generate electricity for spinning mills in one of Pakistan's most important textile centers. Special features of this Jenbacher plant allow for high ambient temperature, dusty inlet air, and operation in island mode. |  |

# technical data

| | |
|---|---|
| Configuration | V 70° |
| Bore (mm) | 135 |
| Stroke (mm) | 170 |
| Displacement/cylinder (lit) | 2.43 |
| Speed (rpm) | 1,500 (50 Hz)<br>1,200/1,800 (60 Hz) |
| Mean piston speed (m/s) | 8.5 (1,500 rpm)<br>6.8 (1,200 rpm)<br>10.2 (1,800 rpm) |
| Scope of supply | Generator set, cogeneration system, generator set/cogeneration in container |
| Applicable gas types | Natural gas, flare gas, propane, biogas, landfill gas, sewage gas. Special gases (e.g., coal mine gas, coke gas, wood gas, pyrolysis gas) |

| Engine type | J312 GS | J316 GS | J320 GS |
|---|---|---|---|
| No. of cylinders | 12 | 16 | 20 |
| Total displacement (lit) | 29.2 | 38.9 | 48.7 |

## Dimensions l x w x h (mm)

| | | |
|---|---|---|
| Generator set | J312 GS | 4,700 x 1,800 x 2,300 |
| | J316 GS | 5,200 x 1,800 x 2,300 |
| | J320 GS | 5,700 x 1,700 x 2,300 |
| Cogeneration system | J312 GS | 4,700 x 2,300 x 2,300 |
| | J316 GS | 5,300 x 2,300 x 2,300 |
| | J320 GS | 5,700 x 1,900 x 2,300 |
| Container | J312 GS | 12,200 x 2,500 x 2,600 |
| | J316 GS | 12,200 x 2,500 x 2,600 |
| | J320 GS | 12,200 x 2,500 x 2,600 |

## Weights empty (kg)

| | J312 GS | J316 GS | J320 GS |
|---|---|---|---|
| Generator set | 8,000 | 8,800 | 10,500 |
| Cogeneration system | 9,400 | 9,900 | 11,000 |
| Container (generator set) | 19,400 | 22,100 | 26,000 |
| Container (cogeneration) | 20,800 | 23,200 | 26,500 |

# outputs and efficiencies

| Natural gas | | 1,200 rpm \| 60 Hz | | | | | 1,500 rpm \| 50 Hz | | | | | 1,800 rpm \| 60 Hz | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NOx < | Type | Pel (kW)[1] | ηel (%) | Pth (kW)[2] | ηth (%) | ηtot (%) | Pel (kW)[1] | ηel (%) | Pth (kW)[2] | ηth (%) | ηtot (%) | Pel (kW)[1] | ηel (%) | Pth (kW)[2] | ηth (%) | ηtot (%) |
| 500 mg/m$^3_N$ | 312 | | | | | | [3] 526 | 39.4 | 635 | 47.6 | 87.0 | 540 | 37.2 | 723 | 49.8 | 87.0 |
| | 312 | 435 | 39.8 | 497 | 45.4 | 85.2 | 625 | 39.8 | 731 | 46.6 | 86.4 | 633 | 38.1 | 808 | 48.6 | 86.7 |
| | 316 | 582 | 40.3 | 649 | 44.9 | 85.2 | 834 | 39.9 | 988 | 47.3 | 87.2 | 848 | 38.2 | 1,079 | 48.7 | 86.9 |
| | 320 | 794 | 40.7 | 870 | 44.5 | 85.2 | 1,063 | 40.8 | 1,190 | 45.6 | 86.4 | 1,060 | 39.0 | 1,313 | 48.3 | 87.3 |
| 250 mg/m$^3_N$ | 312 | | | | | | 526 | 38.6 | 659 | 48.4 | 87.0 | 540 | 36.1 | 767 | 51.3 | 87.4 |
| | 312 | | | | | | 601 | 38.9 | 726 | 47.0 | 85.9 | 633 | 36.7 | 854 | 49.5 | 86.2 |
| | 316 | | | | | | 802 | 39.0 | 967 | 47.0 | 86.0 | 848 | 36.9 | 1,140 | 49.6 | 86.5 |
| | 320 | | | | | | 1,063 | 39.9 | 1,238 | 46.4 | 86.3 | 1,060 | 38.1 | 1,361 | 49.0 | 87.1 |
| 350 mg/m$^3_N$ | 312 | 418 | 38.7 | 500 | 46.2 | 84.9 | 601 | 39.1 | 736 | 47.9 | 87.0 | | | | | |
| | 316 | 559 | 38.8 | 666 | 46.2 | 85.0 | 802 | 39.2 | 983 | 48.0 | 87.2 | | | | | |
| | 320 | 729 | 39.1 | 858 | 46.0 | 85.1 | 1,064 | 40.1 | 1,222 | 46.1 | 86.2 | | | | | |

| Biogas | | 1,200 rpm \| 60 Hz | | | | | 1,500 rpm \| 50 Hz | | | | | 1,800 rpm \| 60 Hz | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NOx < | Type | Pel (kW)[1] | ηel (%) | Pth (kW)[2] | ηth (%) | ηtot (%) | Pel (kW)[1] | ηel (%) | Pth (kW)[2] | ηth (%) | ηtot (%) | Pel (kW)[1] | ηel (%) | Pth (kW)[2] | ηth (%) | ηtot (%) |
| 500 mg/m$^3_N$ | 312 | | | | | | [3] 526 | 40.4 | 558 | 42.9 | 83.3 | 540 | 37.2 | 703 | 48.4 | 85.6 |
| | 312 | | | | | | 625 | 40.0 | 680 | 43.6 | 83.6 | 633 | 38.1 | 787 | 48.4 | 86.5 |
| | 316 | | | | | | [3] 703 | 40.5 | 744 | 42.9 | 83.4 | | | | | |
| | 316 | | | | | | 834 | 39.9 | 910 | 43.7 | 83.6 | 848 | 38.2 | 1,048 | 47.3 | 85.5 |
| | 320 | | | | | | 1,063 | 40.8 | 1,088 | 41.7 | 82.5 | 1,060 | 39.0 | 1,274 | 46.9 | 85.9 |
| 250 mg/m$^3_N$ | 312 | | | | | | | | | | | 633 | 36.7 | 836 | 48.5 | 85.2 |
| | 316 | | | | | | | | | | | 848 | 36.9 | 1,114 | 48.4 | 85.3 |
| | 320 | | | | | | | | | | | 1,060 | 36.9 | 1,387 | 48.3 | 85.2 |

1) Electrical output based on ISO standard output and standard reference conditions according to ISO 3046/I-1991 and p.f. = 1.0 according to VDE 0530 REM with respective tolerance; minimum methane number 70 for natural gas
2) Total heat output with a tolerance of +/- 8%, exhaust gas outlet temperature 120°C, for biogas exhaust gas outlet temperature 180°C
3) Special version with higher compression ratio

All data according to full load and subject to technical development and modification.

### 5.11.3 Cummins CMM Engine

# Low BTU gas generator sets

**> 1540–2000 kW** | QSV91 series

**Our energy working for you.™**

Power Generation

## Standard features

### Single source responsibility

Design, manufacture and testing of engine, alternator, control system and complete generator set are all provided by Cummins.

### Alternator

- Brushless, self-excited machine
- Close voltage regulation
- Rotor and exciter impregnated with oil and acid resisting resin
- Exceptional short circuit capability
- Low waveform distortion with non linear loads

### Applications

- Solid waste landfills
- Municipal sewage digester gas
- Agricultural waste biogas
- Coal mine methane
- Flare gas

### Cummins engine

- Heavy duty 4 cycle water cooled engine
- MCM700/SSM558 full authority electronic management
- Woodward PROACT actuator to drive throttle valve
- CENSE engine monitoring system
- Able to operate on fuels containing corrosive constituents such as $SO_2$, halogens, and siloxanes.
- NOx exhaust emissions as low as 0.5 g/hp-hr (250 mg/Nm³)

### PowerCommand® 3.3

- Full paralleling capability grid and load share
- Integrated voltage regulation
- Superior alternator and generator set protection system
- AmySentry™ alternator protection
- 320 x 240 pixel, multipe lauguages supported operator display panel

## Low BTU gas generator sets | Technical data

| 60 Hz | Electric Output | Fuel Consumption | Electrical Efficiency |
|---|---|---|---|
| **C1750N6C** | 1750 kW | 16.1 mmBTU/h | 37.1% |
| **C2000N6C** | 2000 kW | 18.4 mmBTU/h | 37.8% |

| 50 Hz | Electric Output | Fuel Consumption | Electrical Efficiency |
|---|---|---|---|
| **C1540N5C** | 1540 kW | 4204 kW | 36.6% |
| **C1750N5C** | 1750 kW | 4631 kW | 37.8% |
| **C2000N5C** | 2000 kW | 5287 kW | 37.8% |

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# SECTION 6

# Emission Reductions from Project Implementation

# SECTION 6 CONTENTS

# SECTION 6 EXHIBITS

## 6.1 Introduction

Methane ($CH_4$) is a greenhouse gas (GHG) with a global warming potential (GWP) over 20 times greater than carbon dioxide ($CO_2$). Because of this, projects that capture and utilize or destroy methane that is otherwise vented into the atmosphere will reduce project-related emission and potentially generate a considerable amount of carbon offsets in the process. Ultimately, the monetization of any emission reductions begins with the selection of an appropriate methodology developed under one of the many certification regimes.

The objective of this chapter is to estimate emission reductions from the proposed project activity. The following chapter discusses the methodology selection process, considers how the methodology applies to the project, and then calculates project-related emission reductions according to the selected methodology.

## 6.2 Methodology Selection

The proposed project would reduce the amount of coal mine methane liberated by capturing and combusting (oxidizing) methane that would otherwise be emitted to the atmosphere. If done according to the systems and procedures of a specific certification regime, the proposed project could generate carbon offsets. Numerous certification standards exist with approved methodologies for coal mine methane projects. Many of these methodologies are based on existing methodologies approved under the UNFCCC-accredited clean development mechanism (CDM), which is the most well-known of the international certification regimes.

Currently, there are now some 5,365 active projects in the CDM pipeline; another 1,074 have been withdrawn or rejected by either the Executive Board (EB) or by Designated Operational Entities (DOEs) (Exhibit 6-1). Of the active projects in the CDM pipeline, 2,306 have been registered, 141 projects are in the process of registration, and 2,918 are at validation. Nearly 40% of the active projects in the CDM pipeline are hosted by China. Currently, China is the number one country by issued certified emission reductions (CERs) (claiming 45% or 210 million CERs) and they account for over half of CERs expected by 2012 and 2020 (54% and 55%, respectively) (Fenhann, 2010).

| Project Status | Total Number of Projects | Projects in China |
|---|---|---|
| **Total At Validation** | **2,918** | **1,150** |
| **Total in the Process of Registration** | **141** | **86** |
| Request for Registration | 43 | 18 |
| Request for Review | 60 | 43 |
| Correction Requested | 35 | 23 |
| Under Review | 3 | 2 |
| **Total Withdrawn or Rejected** | **1,074** | **291** |
| Withdrawn | 49 | 11 |
| Rejected by EB | 172 | 71 |
| Rejected by DOEs | 853 | 209 |
| **Total Registered** | **2,306** | **913** |
| Registered, no issuance of CERs | 1,558 | 654 |
| Registered, CER issued | 748 | 259 |
| **Total Number of Projects (including rejected & withdrawn)** | **6,439** | **2,440** |
| **Active Projects in the Pipeline** | **5,365** | **2,149** |

**Exhibit 6-1: Status of CDM Projects in China as of 1 August 2010**
(Fenhann, 2010)

Due to methane's high global warming potential, CMM projects can generate significant carbon offsets and have become one of the leading CDM project types. Currently, there are 70 active CBM/CMM projects in the CDM pipeline. Of the 70 projects, 68 are hosted in China with one each in Mexico and India. As shown in Exhibit 6-2, to date 27 of the projects submitted have been registered by the CDM EB, and ten CBM/CMM projects have been issued CERs, all of which are categorized in either the coal mine methane or coal mine methane & VAM project sub-types (Fenhann, 2010).

| Project Sub-Type | Number of CBM/CMM Projects | | | | kCERs Issued (No. of Projects) | MW Installed |
|---|---|---|---|---|---|---|
| | At Validation | Request Registration/ Review | Registered | Total | | |
| Coal Mine Methane | 28 | 10 | 23 | 61 | 2,782(8) | 1,036 |
| Coal Bed Methane | 1 | 0 | 0 | 1 | 0(0) | 0 |
| Coal Mine Methane & VAM | 1 | 0 | 4 | 5 | 25(2) | 51 |
| Ventilation Air Methane | 3 | 0 | 0 | 3 | 0(0) | NA |
| **Total** | **33** | **10** | **27** | **70** | **2,807(10)** | **1,087** |

**Exhibit 6-2: Coal Bed and Coal Mine Methane Projects by Project Sub-Type**
(Fenhann, 2010)

The only two CBM/CMM projects outside of China are a CMM project at the Mimosa Coal Mine in Coahuila, Mexico, and a CBM project at the GEECL Block in Raniganj (South), West Bengal, India. The Indian project was the first CDM project submitted for validation under the coal bed methane project sub-type (Fenhann, 2010). China is clearly the dominant player in CBM/CMM projects under the CDM and it is the only host country where such projects have been issued CERs. As shown in Exhibit 6-3, between February 2008 and August 2010 China has been issued 2.8 million CERs


**Exhibit 6-3: Cumulative CERs Issued for Coal Mine Methane Projects in China**
(source data from Fenhann, 2010)

A total of 84 CBM/CMM projects (including all 70 currently active CBM/CMM projects) have been submitted according to the specifications of the approved *Consolidated methodology for coal bed methane, coal mine methane and ventilation air methane capture and use for power (electrical or motive) and heat and/or destruction through flaring or flameless oxidation* (ACM0008, Version 6). In particular, as illustrated in Exhibit 6-4, all 6 projects with emission reductions from both CMM and VAM (as in the proposed project at Mine No. 6) utilize ACM0008. This methodology accounts for (1) reductions in methane vented/emitted from the mine to the atmosphere and its equivalent in carbon dioxide emissions avoided, and (2) the equivalent carbon dioxide emissions avoided by using the captured methane to generate electricity instead of energy production from alternative fossil fuel resources such as coal. As such, we will use ACM0008 as the methodology to estimate project-related emission reductions.

| Project | Province | Status | Methodology | Credit Start | 2012 $ktCO_2$ | 2020 $ktCO_2$ | kCERs Issued | MW Installed |
|---|---|---|---|---|---|---|---|---|
| Hebi | Henan | Validation Terminated | ACM8+ACM2 | 1 Jun 07 | 1,487 | 3,507 | 0 | 11.0 |
| Yima | Henan | Registered | ACM8+ACM2 | 2 Aug 08 | 1,177 | 3,306 | 13 | 11.0 |
| Pingdingshan | Henan | Registered | ACM8+ACM2 | 22 Aug 08 | 2,670 | 7,591 | 0 | 19.5 |
| Zhenhzhou | Henan | Registered | ACM8+ACM2 | 5 Sep 08 | 1,639 | 4,710 | 12 | 8.0 |
| Anhui Huaibei Taoyuan | Anhui | Registered | ACM8 | 6 Oct 09 | 144 | 501 | 0 | 0.0 |
| Hegang | Heilongjiang | At Validation | ACM8 | 1 Oct 08 | 1,182 | 2,781 | 0 | 12.5 |

**Exhibit 6-4: CDM Projects with Emission Reductions from Both CMM & VAM**

It is important to note that while CBM/CMM projects using ACM0008 under the CDM offer a blueprint for calculating emission reductions associated with the proposed project, the CDM is not the only certification regime that could be pursued, nor is the ACM0008 the only applicable methodology. Furthermore, the use of ACM0008 does not guarantee approval of the proposed projects by the CDM EB; its application is meant only as an illustration of the project's potential to generate emission reductions. If a carbon finance mechanism is pursued for the project, further due diligence on the part of the project developer should include an investment analysis and consider, among other things, the evolving regulatory framework in China and the effect of host-country regulations on project additionality.

## 6.3 Description of the Project Activity

The proposed project is located at Mine No. 6 and will utilize the available gas for the production of both electricity and heat. A number of technically feasible project scenarios were explored and are discussed in detail in Sections 4 and 5. The recommended project approach (see Section 7.4.6) is to upgrade the degasification system and utilize methane liberated from Mine No. 6 in two ways. Firstly, a set of 5 gas engines with a total capacity of 2.5 MW will be added to the 5 existing gas engines in order to utilize 100% of the extracted CMM to produce electricity and heat. The power produced will be used for the mine's own consumption, replacing electricity that would otherwise be purchased from the Central China Power Grid (CCPG). Waste heat from the engines will be utilized to supply hot water to nearby mining facilities. Secondly, up to two units of a methane oxidation technology will be installed at the East Wing ventilation shaft to destroy ventilation air methane (VAM) with low $CH_4$ concentrations (below 1%). This technology will also produce thermal energy that can be substituted for coal-based heat.

Exhibit 6-5 shows the project's total gas utilization and expected energy output.

| | **Project** |
|---|---|
| CMM Drainage ($m^3$ $CH_4$/d) | 28,750 |
| CMM Utilization ($m^3$ $CH_4$/d) | 28,750 |
| VAM Venting* ($m^3$ $CH_4$/d) | 51,035 |
| VAM Utilization* ($m^3$ $CH_4$/d) | 30,621 |
| Electricity Production (MWh/yr) | 35,040 |
| Heat Production (GJ/yr) | 102,345 |

* East Wing ventilation shaft only.

**Exhibit 6-5: Project's Methane Utilization and Energy Output (at Full Capacity) Compared to Baseline**

Total emission reductions over a ten-year crediting period are estimated at **2,378,800 $tCO_2e$** (Exhibit 6-6). However, it is important to note that the utilization of methane with a $CH_4$ concentration above 30% in gas engines currently falls into a gray area with respect to the additionality criterion under the CDM. In recognition of this, the emission reductions from the CMM and VAM portions of the proposed project are calculated separately throughout Section 7.5 in order to allow potential project developers to make an independent assessment of the project's potential to generate carbon offsets.

| **Year** | **Annual Estimate of Emission Reductions in $tCO_2e$** |
|---|---|
| Year 1 | 237,880 |
| Year 2 | 237,880 |
| Year 3 | 237,880 |
| Year 4 | 237,880 |
| Year 5 | 237,880 |
| Year 6 | 237,880 |
| Year 7 | 237,880 |
| Year 8 | 237,880 |
| Year 9 | 237,880 |
| Year 10 | 237,880 |
| **Total Estimated Reductions ($tCO_2e$)** | **2,378,800** |
| **Total Number of Crediting Years** | **10 years** |
| **Annual Average of Emission Reductions Over the First Crediting Period ($tCO_2e$)** | **237,880** |

**Exhibit 6-6: Estimated Emission Reductions throughout the First Crediting Period**

## 6.4 Application of Selected Methodology

### 6.4.1 Justification of Methodology Selection and Assessment of Applicability to the Project Activity

The project uses the approved *Consolidated methodology for coal bed methane, coal mine methane and ventilation air methane capture and use for power (electrical or motive) and heat and/or destruction through flaring or flameless oxidation* (ACM0008, Version 6)[1].

The applicability of ACM0008 to the proposed project activities is summarized in Tables 6 through 9. The information presented in the following tables illustrates that this is an appropriate methodology given the proposed extraction and utilization/destruction project activities.

| CMM Extraction Techniques Eligible Under ACM0008 | Activities of Project |
|---|---|
| Surface drainage wells to capture CBM associated with mining activities | The proposed project activity does not include any CBM capture |
| Underground boreholes in the mine to capture pre-mining CMM | Cross-panel directionally drilled boreholes are recommended |
| Surface goaf wells, underground boreholes, gas drainage galleries or other goaf gas capture techniques, including gas from sealed areas, to capture post-mining CMM | In-mine directionally drilled horizontal gob boreholes are recommended |
| Ventilation CMM that would normally be vented | In the absence of project, 100% of VAM is vented |

**Exhibit 6-7: CMM Extraction Techniques Eligible Under ACM0008**

| CMM Utilization Techniques Eligible Under ACM0008 | Activities of Project |
|---|---|
| Methane is captured and destroyed through flaring and/or flameless oxidation | Included. A portion of VAM will be oxidized in two methane oxidizer units |
| Methane is captured and destroyed through utilization to produce electricity, motive power, and/or thermal energy | CMM is extracted and captured for power and heat production; A share of VAM is also used for heat production; Emission reductions are claimed for avoiding energy from other sources |
| The remaining share of methane, to be diluted for safety reasons, may still be vented | VAM that is not fed to the oxidizer for heat generation will be vented |
| All the CBM or CMM captured by the project should either be used or destroyed, and cannot be vented | All of the captured CMM is used to generate electricity and/or heat; No CBM is used in the project |

**Exhibit 6-8: CMM Utilization Techniques Eligible Under ACM0008**

[1] ACM0008 is available at:
http://cdm.unfccc.int/UserManagement/FileStorage/NFOHG1YM2E3SX7CRJ5A09QVDPZUW64

| Other Eligibility Criteria of ACM0008 | Activities of Project |
|---|---|
| Project participants must be able to supply the necessary data for *ex-ante* projections of methane demand as described in Section 6.5, Calculation of Emission Reductions | All necessary data is available |
| The project cannot operate in open cast mines | All mines included in project are underground |
| The project cannot capture methane from abandoned/decommissioned mines | All mines included in project are active |
| The project cannot capture/use virgin coalbed methane independently of any mining activities | No CBM will be used in project |
| The project cannot use $CO_2$ or any other fluid/gas to enhance CBM drainage before mining takes place | No enhanced CBM drainage will be used in project |

**Exhibit 6-9: Other Eligibility Criteria of ACM0008**

### 6.4.2 Description of the Sources and Gases Included in the Project Boundary

The sources and gases included in the project boundary for determination of both baseline and project emissions are presented in Exhibit 6-10.

| | Source | Gas | | Justification/Explanation |
|---|---|---|---|---|
| Baseline Emissions | Emissions of methane as a result of venting | $CH_4$ | Included | Approximately 31% of CMM captured and 100% of VAM in the baseline scenario is vented. This is the main emission source. |
| | Emissions from destruction of methane in the baseline | $CO_2$ | Included | Approximately 69% of captured CMM is used for heat and power. |
| | | $CH_4$ | Excluded | Excluded for simplification. This is conservative. |
| | | $N_2O$ | Excluded | Excluded for simplification. This is conservative. |
| | Grid electricity generation | $CO_2$ | Included | Emissions from Central China Power Grid equivalent to power generated by project activity. |
| | | $CH_4$ | Excluded | Excluded for simplification. This is conservative. |
| | | $N_2O$ | Excluded | Excluded for simplification. This is conservative. |
| | Captive power and/or heat, and vehicle fuel use | $CO_2$ | Included | Emissions from coal boilers that will be displaced by heat generated by gas engines and oxidizers. |
| | | $CH_4$ | Excluded | Excluded for simplification. This is conservative. |
| | | $N_2O$ | Excluded | Excluded for simplification. This is conservative. |
| Project Emissions | Emissions of methane as a result of continued venting | $CH_4$ | Excluded | Only the change in CMM and VAM emissions released will be taken into account by monitoring the methane utilized or destroyed by the project activity. |
| | On-site fuel (energy) consumption due to the project activity, including transport of the gas | $CO_2$ | Included | Electricity consumed by the Central China Power Grid required to operate oxidizer fans and ancillary equipment for CMM utilization such as cooling water pumps. |
| | | $CH_4$ | Excluded | Excluded for simplification. This emission source is assumed to be very small. |
| | | $N_2O$ | Excluded | Excluded for simplification. This emission source is assumed to be very small. |
| | Emissions from methane destruction | $CO_2$ | Included | Emissions from CMM utilized in gas engines and emissions from VAM utilized in oxidizer unit. |
| | Emissions from NMHC destruction | $CO_2$ | Excluded | Assumed NMHC account for less than 1% of volume in extracted gas and can be excluded per ACM0008. However, the level of NMHC should be continuously monitored throughout the project. |
| | Fugitive emissions of unburned methane | $CH_4$ | Included | Unburned methane from gas engines and oxidizer. |
| | Fugitive methane emissions from on-site equipment | $CH_4$ | Excluded | Excluded for simplification. This emission source is assumed to be very small. |
| | Fugitive methane emissions from gas supply pipeline or in relation to use in vehicles | $CH_4$ | Excluded | Excluded for simplification. This emission source is assumed to be very small. |
| | Accidental methane release | $CH_4$ | Excluded | Excluded for simplification. This emission source is assumed to be very small. |

**Exhibit 6-10: Sources and Gases in Project Boundary**

Exhibit 6-11 presents a diagram of the project boundary for the proposed project activity.

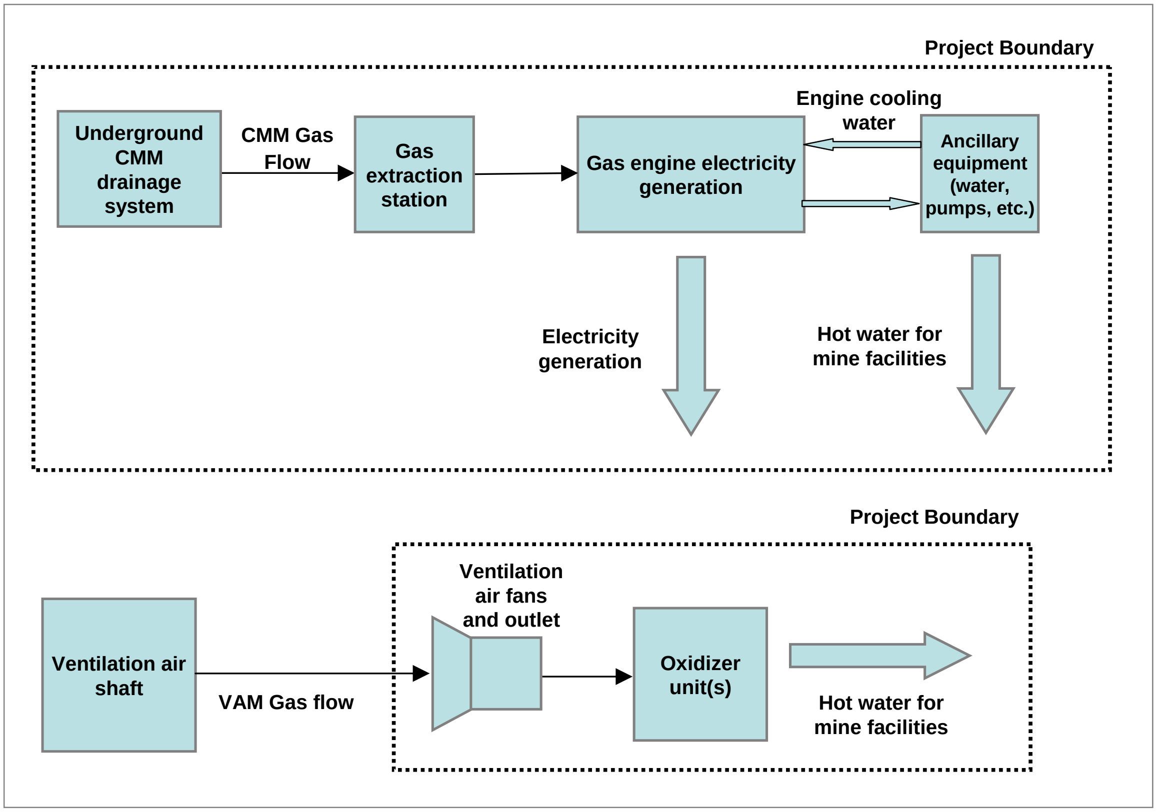


**Exhibit 6-11: Project Boundary**

### 6.4.3 Explanation of Methodological Choices

This project adopted the approved consolidated methodology ACM0008. The calculations of project emission, baseline emission, leakage, and emission reductions are outlined in steps 1 through 4 below.

#### 6.4.3.1 Project emissions

Based on ACM0008, the following formulae are used to calculate emission related to the proposed project activity.

$$PE_y = PE_{ME} + PE_{MD} + PE_{UM} \qquad \textbf{(1)}$$

Where:

| | |
|---|---|
| $PE_Y$ | Project emissions in year y ($tCO_2e$) |
| $PE_{ME}$ | Project emissions from additional energy use to capture and use methane ($tCO_2e$) |
| $PE_{MD}$ | Project emissions from methane destroyed ($tCO_2e$) |
| $PE_{UM}$ | Project emissions from un-combusted methane ($tCO_2e$) |

**$PE_{ME}$: Emissions from additional energy use to capture and use methane**

In the CMM-to-power portion of the project, additional electricity will be used by the gas extraction stations and for pumping CMM and water to the gas generators. In the VAM-to-heat portion of the project, additional electricity will be used to run the oxidizer fans[2], and fossil fuel (propane) will be used to preheat the oxidation units[3]. Therefore, emissions from additional energy consumption will be calculated according to the following formula:

$$PE_{ME} = CONS_{ELEC,PJ} \times EF_{ELEC} + CONS_{FossFuel,PJ} \times EF_{FossFuel} \qquad \textbf{(2)}$$

Where:

| | |
|---|---|
| $CONS_{ELEC,PJ}$ | Additional electricity consumption for capture and use of methane (MWh) |
| $EF_{ELEC}$ | Carbon emission factor of Central China Power Grid ($tCO_2e$/MWh) |
| $CONS_{FossFuel,PJ}$ | Additional fossil fuel consumption for capture and use or destruction of methane (GJ) |
| $EF_{FossFuel}$ | Carbon emissions factor of fossil fuel (propane) ($tCO_2e$/GJ) |

**$PE_{MD}$: Emissions from methane destroyed**

When the captured methane is burned for power and/or heat in the CMM power plant and VAM oxidizers, combustion emissions are released. In accordance with ACM0008, if NMHC account for more than 1% by volume of the extracted CMM, combustion emissions from these gases should also be included. For simplification, it is assumed that the concentration of NMHC in extracted CMM from Mine No. 6 is lower than 1%. Therefore, combustion emissions from non-methane hydrocarbons are ignored in ex ante emission calculations. When the project begins operation, the concentration of NMHC should be monitored.

The project activities include supplying CMM and VAM to gas engines and oxidizer units, respectively, and no other technologies such as flaring, heat generation, and supply to gas grid are being applied. Therefore, the formula to calculate emissions from methane destruction is expressed as follows:

$$PE_{MD} = (MD_{OX} + MD_{ELEC}) \times EF_{CH4} \qquad \textbf{(3)}$$

Where:

| | |
|---|---|
| $MD_{OX}$ | Methane destroyed through flameless oxidation ($tCH_4$) |
| $MD_{ELEC}$ | Methane destroyed through power generation ($tCH_4$) |
| $EF_{CH4}$ | Carbon emission factor for combusted methane ($tCO_2e/tCH_4$) |

[2] VAM oxidizer units will consume electricity in fan motors, which are required to push the VAM through the unit without creating any back-pressure on the existing mine ventilation systems.
[3] Pre-heating of VAM oxidizer units prior to start-up will utilize some form of heat, most likely bottled butane or propane. Emissions from this source will be counted at $CONS_{FossFuel,PJ}$.

And:

$MD_{OX} = MM_{OX} \times Eff_{OX}$ **(4)**

$MD_{ELEC} = MM_{ELEC} \times Eff_{ELEC}$ **(5)**

Where:

| | |
|---|---|
| $MM_{OX}$ | Methane measured sent to oxidizer ($tCH_4$) |
| $Eff_{OX}$ | Efficiency of methane destruction in oxidizer |
| $MM_{ELEC}$ | Methane measured sent to power plant ($tCH_4$) |
| $Eff_{ELEC}$ | Efficiency of methane destruction in power plant |

**$PE_{UM}$: Emissions from un-combusted methane**

Not all of the methane used to generate electricity and/or heat will be combusted; a small amount will escape into the atmosphere. These emissions are calculated using the following formula:

$PE_{UM} = [MM_{ELEC} \times (1 - Eff_{ELEC}) + MM_{OX} \times (1 - Eff_{OX})] \times GWP_{CH4}$ **(6)**

Where:

| | |
|---|---|
| $MM_{ELEC}$ | Methane measured sent to power plant ($tCH_4$) |
| $Eff_{ELEC}$ | Efficiency of methane destruction in power plant |
| $MM_{OX}$ | Methane measured sent to oxidizer ($tCH_4$) |
| $Eff_{OX}$ | Efficiency of methane destruction in oxidizer |
| $GWP_{CH4}$ | Global warming potential of methane ($tCO_2e/tCH_4$) |

#### 6.4.3.2 Baseline emissions

The current practices and conditions at Mine No. 6 are used for the purpose of calculating baseline emissions. This business-as-usual scenario includes the following:

Extraction Activities: Gas is extracted by a combination of ventilation as well as pre- and post-mining extraction.

Utilization Activities: A portion (69%) of the drained CMM is captured and utilized for heat and power, while the remainder of the gas (31%) is vented. In the baseline scenario, 100% of VAM is vented.

Energy Production: Currently, the electricity needs of the mine are met by electricity from the CCPG, while heat requirements are satisfied by heat recovered from existing CMM generators and heat supplied by waste coal-fired boilers.

Based on ACM0008, the following formulae are used to calculate baseline emissions.

$$BE_y = BE_{MD,y} + BE_{MR,y} + BE_{Use,y} \quad \textbf{(7)}$$

Where:

| | |
|---|---|
| $BE_y$ | Baseline emissions in year y ($tCO_2e$) |
| $BE_{MD,y}$ | Baseline emissions from destruction of methane in the baseline scenario in year y ($tCO_2e$) |
| $BE_{MR,y}$ | Baseline emissions from release of methane into the atmosphere in year y that is avoided by the project activity ($tCO_2e$) |
| $BE_{Use,y}$ | Baseline emissions from the production of power, heat, or supply to gas grid replaced by the project activity in year y ($tCO_2e$) |

**$BE_{MD,y}$: Baseline emissions from destruction of methane in the baseline scenario**

In the baseline scenario, 69% of the extracted CMM is utilized in the existing CMM-fired power plant.  Therefore, baseline emissions from the destruction of methane are calculated as follows:

$$BE_{MD,y} = EF_{CH4} \times CMM_{BLi,y} \quad \textbf{(8)}$$

*Where:*

| | |
|---|---|
| $EF_{CH4}$ | Carbon emission factor for combusted methane ($tCO_2e/tCH_4$) |
| $CMM_{BLi,y}$ | Pre-mining CMM that would have been captured, sent to and destroyed by use in *i* in the baseline scenario in the year *y* ($tCH_4$) |
| i | Use of methane (power generation) |

**$BE_{MR,y}$ : Baseline emissions from release of methane into the atmosphere**

The baseline methane emissions that are still vented in the project scenario are not accounted for in the project emissions or in the baseline emissions since they are vented in both scenarios. Since the project makes no distinction between pre- and post-mining CMM, and since there are no emissions from CBM, baseline emissions from release of methane are calculated using the following formula:

$$BE_{MR,y} = GWP_{CH4} \times [\sum_i (CMM_{PJi,y} - CMM_{BLi,y}) + \sum_i (VAM_{PJi,y} - VAM_{BLi,y})] \quad \textbf{(9)}$$

Where:

| | |
|---|---|
| $GWP_{CH4}$ | Global warming potential of methane ($tCO_2e/tCH_4$) |
| i | Use of methane (power generation) |
| $CMM_{PJi,y}$ | Pre-mining CMM captured, sent to and destroyed by use *i* in the project activity in year y ($tCH_4$) |
| $CMM_{BLi,y}$ | Pre-mining CMM that would have been captured, sent to and destroyed by use *i* in the baseline scenario in year y ($tCH_4$) |

| | |
|---|---|
| $VAM_{PJi,y}$ | VAM sent to and destroyed by use *i* in the project activity in year y ($tCH_4$). In the case of flameless oxidation, $VAM_{PJi,y}$ is equivalent to $MD_{ox}$ defined previously. |
| $VAM_{BLi,y}$ | VAM that would have been captured, sent to and destroyed by use *i* in the baseline scenario in year y ($tCH_4$) |

**$BE_{Use,y}$: Baseline emissions from the production of power and heat replaced by the project activity**

In accordance with ACM0008, the formula to calculate total baseline emissions from the production of power or heat replaced by the project activity is as follows:

$$BE_{Use,y} = ED_{CBMw,y} + ED_{CBMz,y} + ED_{CPMM,y} \qquad \textbf{(10)}$$

Where:

| | |
|---|---|
| $ED_{CBMw,y}$ | Emissions from displacement of end uses by use of coal bed methane captured from wells where the mining area intersected the zone of influence in year y ($tCO_2$) |
| $ED_{CBMz,y}$ | Emissions from displacement of end uses by use of coal bed methane captured from wells where the mining area intersected the zone of influence prior to year y ($tCO_2$) |
| $ED_{CPMM,y}$ | Emissions from displacement of end uses by use of coal mine methane, VAM and post-mining methane ($tCO_2$) |

Since the proposed project excludes capture and use of coal bed methane, equation 10 reduces to the following:

$$BE_{Use,y} = ED_{CPMM,y} \qquad \textbf{(11)}$$

ACM0008 defines $ED_{CPMM,y}$ as follows:

$$ED_{CPMM,y} = \frac{CMM_{PJ,y} + PMM_{PJ,y} + VAM_{PJ,y}}{CBMM_{tot,y}} \times PBE_{Use,y} \qquad \textbf{(12)}$$

Where:

| | |
|---|---|
| $CMM_{PJ,y}$ | Pre-mining CMM captured by the project activity in year y ($tCH_4$) |
| $PMM_{PJ,y}$ | Post-mining CMM captured by the project activity in year y ($tCH_4$) |
| $VAM_{PJ,y}$ | VAM captured by the project activity in year y ($tCH_4$) |
| $CBMM_{tot,y}$ | Total CBM, CMM and VAM captured and utilized by the project activity in year y ($tCH_4$) |
| $PBE_{Use,y}$ | Potential total baseline emissions from the production of power or heat replaced by the project activity in years y ($tCO_2e$) |

Since no distinction is made between pre- and post-mining CMM, equation 12 reduces to the following:

$$ED_{CPMM,y} = \frac{CMM_{PJ,y} + VAM_{PJ,y}}{CBMM_{tot,y}} \times PBE_{Use,y} \quad \textbf{(13)}$$

Assuming all CMM and VAM captured by the project is utilized, $CMM_{PJ,y}$ plus $VAM_{PJ,y}$ is equal to $CBMM_{tot,y}$ and equation 13 reduces further to the following:

$$ED_{CPMM,y} = PBE_{Use,y} \quad \textbf{(14)}$$

Substituting equation 11 results in the following:

$$BE_{Use,y} = PBE_{Use,y} \quad \textbf{(15)}$$

For the proposed project, $PBE_{Use,y}$ is calculated as follows:

$$PBE_{Use,y} = GEN_y \times EF_{ELEC} + HEAT_y \times EF_{HEAT} \quad \textbf{(16)}$$

Where:

| | |
|---|---|
| $PBE_{Use,y}$ | Potential total baseline emissions from the production of power or heat replaced by the project activity in year y ($tCO_2e$) |
| $GEN_y$ | Electricity generated by project activity in year y (MWh) |
| $EF_{ELEC}$ | Emissions factor of electricity replaced by project ($tCO_2$/MWh) |
| $HEAT_y$ | Heat generation by project activity in year y (GJ) |
| $EF_{HEAT}$ | Emissions factor for heat production replaced by project activity ($tCO_2$/GJ) |

Since the electricity generated by the proposed project will displace the electricity from the CCPG in the baseline scenario, the emission factor for the CCPG will be applied to this project.

ACM0008 uses the following formula to calculate the emission factor of heat ($EF_{HEAT}$) that is displaced by the project:

$$EF_{heat,y} = \frac{EF_{CO2,i}}{Eff_{heat}} \times \frac{44\,CO_2}{12\,C} \times \frac{1TJ}{1000GJ} \quad \textbf{(17)}$$

Where:

| | |
|---|---|
| $EF_{CO2,i}$ | $CO_2$ emissions factor of fuel used in heat generation (tC/TJ) |
| $Eff_{heat}$ | Boiler efficiency of the heat generation |
| 44/12 | Carbon to carbon dioxide conversion factor |
| 1/1000 | TJ to GJ conversion factor |

#### 6.4.3.3 Leakage

Project leakage $LE_y$ is calculated from the following formula:

$$LE_y = LE_{d,y} + LE_{o,y} \qquad \textbf{(18)}$$

Where:

| | |
|---|---|
| $LE_y$ | Leakage emissions in year y ($tCO_2e$) |
| $LE_{d,y}$ | Leakage emissions due to displacement of other baseline thermal energy uses of methane in year y ($tCO_2e$) |
| $LE_{o,y}$ | Leakage emissions due to other uncertainties in year y ($tCO_2e$) |

**$LE_{d,y}$: Leakage emissions due to displacement of other baseline thermal energy uses**

Baseline thermal energy demand currently exists, however, the proposed project will supplement existing thermal energy supplies with thermal energy from new gas engines and oxidizer units. As the project more than doubles the thermal energy supply, it is assumed that the project will not prevent CMM from meeting baseline thermal demand. As such, there is no increase in emissions outside of the project boundary associated with meeting thermal energy demand with other fuels. Therefore, this form of leakage can be excluded.

**$LE_{o,y}$: Leakage emissions due to other uncertainties**

Three types of leakage due to other uncertainties are considered in ACM0008:

a) CBM drainage from outside the de-stressed zone
b) Impact of CDM project activity on coal production
c) Impact of CDM project activity on coal prices and market dynamics

Leakage category a) can be excluded because the project does not involve any CBM capture. Leakage category b) requires a discount factor to be applied *if the project activity is CBM/CMM extraction and the baseline scenario is ventilation only*. This does not apply to the current project because CMM extraction is already part of the baseline. While the impact of leakage category c) may be theoretically possible, reliable scientific information is not currently available to asses this risk and to determine if the phenomenon would be negligible or not. Moreover, it is difficult to assess ex-ante the contribution of any particular project given the dynamic nature of local and global coal markets. Therefore, the leakage due to the impact of the proposed project on coal prices and market dynamics is not taken into account.

As a result, leakage emissions due to uncertainties are excluded from the project.

#### 6.4.3.4 Emission Reductions

The emission reduction ($ER_y$) by the project activity during a given year (y) is calculated as follows:

$$ER_y = BE_y - PE_y - LE_y \quad \textbf{(19)}$$

Where:

| | |
|---|---|
| $ER_y$ | Emission reductions of the project activity during the year y ($tCO_2e$) |
| $BE_y$ | Baseline emissions during the year y ($tCO_2e$) |
| $PE_y$ | Project emissions during the year y ($tCO_2e$) |
| LEy | Leakage emissions in year y ($tCO_2e$) |

## 6.5 Calculation of Emission Reductions

### 6.5.1 Inputs and Assumptions

The inputs and assumptions used in the calculation of emission reductions are defined and described in Exhibit 6-12.

**General Parameters**

| Parameter | Unit | Value | Source |
|---|---|---|---|
| Global warming potential of methane ($GWP_{CH4}$) | $tCO_2e/tCH_4$ | 21 | IPCC, 2006 |
| Emission factor for combusted methane ($EF_{CH4}$) | $tCO_2/tCH_4$ | 2.75 | UNFCCC, 2009 |
| Density of methane | $kg/m^3$ | 0.67 | IPCC, 2006 |
| Efficiency of methane destruction in power plant ($Eff_{ELEC}$) | % | 99.5% | IPCC, 2006 |
| NCV methane | $MJ/m^3$ | 33.7 | API, 2004 |
| Emission factor coal | tC/TJ | 25.8 | IPCC, 2006 |
| Emission factor for propane ($EFF_{FOSSFUEL}$) | $tCO_2e/GJ$ | 0.0598 | EIA |
| Efficiency of methane destruction in Oxidizer ($Eff_{OX}$) | % | 96.0% | Biothermica, 2007 |
| Boiler efficiency of heat generation | % | 100% | Assumption (ACM0008 Option B) |
| Emission factor heat ($EF_{HEAT}$) | $tCO_2e/GJ$ | 0.095 | Calculation |
| Emission factor Central China Electricity Grid ($EF_{ELEC}$) | $tCO_2e/MWh$ | 0.9747 | NDRC |

**Gas Engine Parameters**

| Baseline Parameters | Unit | Value | Source |
|---|---|---|---|
| Gas engine operation time | hours/year | 5,694 | Assumption |
| Gas engine gas utilization (per engine) | $m^3$ $CH_4$/hr | 153 | Calculation |
| Gas engine capacity | MW | 0.5 | HECG |
| Number of gas engines installed | engines | 5.0 | HECG |
| Gas engine electrical efficiency | % | 35.0% | HECG |

| Project Parameters | Unit | Value | Source |
|---|---|---|---|
| Gas engine operation time - New Engines | hours/year | 8,322 | Assumption |
| Gas engine gas utilization (per engine) | $m^3$ $CH_4$/hr | 153 | Calculation |
| Gas engine capacity - New Engines | MW | 0.5 | Assumption |
| Number of gas engines installed - New Engines | engines | 5 | Assumption |
| Number of gas engines installed - Total Project | engines | 10.0 | Assumption |
| Gas engine electrical efficiency - New Engines | % | 35.0% | Assumption |
| Gas engine heat efficiency | % | 30.0% | Assumption |
| Gas engine heat generation | GJ/hr | 0.4629 | Calculation |
| Share of gas engine heat used | % | 30.0% | Assumption |
| Gas engine ancillary equipment electricity consumption | kW/engine | 19.6 | Eco-Carbone, 2007 |
| Water cycle pumps | kW/engine | 11.25 | Eco-Carbone, 2007 |
| Hot water pumps | kW/engine | 2.5 | Eco-Carbone, 2007 |
| Cold water pumps | kW/engine | 0.125 | Eco-Carbone, 2007 |
| Cooling water towers | kW/engine | 2.75 | Eco-Carbone, 2007 |
| Water to steam conversion | kW/engine | 2.75 | Eco-Carbone, 2007 |
| Water softener pumps | kW/engine | 0.2 | Eco-Carbone, 2007 |

**VAM Oxidizer Parameters**

| Parameter | Unit | Value | Source |
|---|---|---|---|
| Oxidizer operation time | hours/year | 8,322 | Biothermica, 2009 |
| Oxidizer capacity (per unit) | $m^3$ air/hr | 169,875 | Biothermica, 2009 |
| Number of oxidizer units installed | units | 2 | Assumption |
| Oxidizer gas utilization - project (per unit) | $m^3$ CH4/hr | 663 | Calculation |
| Average VAM CH4 concentration | % | 0.39% | HECG |
| VAM capture efficiency | % | 60.0% | Biothermica, 2009 |
| Oxidizer heat generation | GJ/hr | 4.2 | Biothermica, 2009 |
| Share of Oxidizer heat used | % | 30.0% | Assumption |
| Oxidizer electricity consumption - heat only scenario | kW | 286.5 | Biothermica, 2009 |
| Oxidizer burner fossil fuel consumption | GJ/hr | 2.5 | Biothermica, 2007 |
| Burner hours/unit | hr/yr | 60 | Biothermica, 2007 |

**Exhibit 6-12: Inputs and Assumptions Used to Calculate Project Related Emission Reductions**

### 6.5.2 Project Emissions

The project emissions are calculated based on equation (1) in section 6.4.3.1

$$PE_y = PE_{ME} + PE_{MD} + PE_{UM} \quad \textbf{(1)}$$

***Combustion emissions from additional energy required for CMM/VAM capture and use***

**$PE_{ME}$: Project emissions from energy use to capture and use methane**

$$PE_{ME} = CONS_{ELEC,PJ} \times EF_{ELEC} + CONS_{FossFuel,PJ} \times EF_{FossFuel} \quad \textbf{(2)}$$

***CMM Project Component***

| | |
|---|---|
| Total number of gas engines installed: | 10 engines (5 old; 5 new) |
| Ancillary equipment electricity consumption: | 19.6 kW/engine |
| Operating hours of gas engine: | 5,694 hours/year (old); 8,322 hours/year (new) |
| $EF_{ELEC}$: | 0.9747 $tCO_2e$/MWh |

Additional electricity consumption from ancillary equipment
= (5 engines x 19.6 kW/engine x 5,694 hours/year + 5 engines x 19.6 kW/engine x 8,322 hours/year) x 1 MW/1,000 kW = 1,374 MWh/year

Project emissions from energy use to capture and use CMM ($PE_{ME}$)
= 1,374 MWh/year x 0.9747 $tCO_2e$/MWh = 1,339 $tCO_2e$/year

***VAM Project Component***

| | |
|---|---|
| Total number of oxidizer units installed: | 2 units |
| Electricity consumption of oxidizers: | 286.5 kW/unit |
| Operating hours of oxidizer units: | 8,322 hours/year |
| Oxidizer burner fossil fuel consumption: | 2.5 GJ/hour |
| Oxidizer burner hours: | 60 hours/unit/year |
| $EF_{ELEC}$: | 0.9747 $tCO_2e$/MWh |
| $EF_{FossFuel,PJ}$: | 0.0598 $tCO_2e$/GJ |

Additional electricity consumption from oxidizers
= 2 oxidizer units x 286.5 kW/unit x 8,322 hours/year x 1 MW/1,000 kW = 4,769 MWh/year

Additional fossil fuel consumption for preheating oxidizer
= 2 oxidizer units x 2.5 GJ/hour x 60 hours/unit/year = 300 GJ/year

Project emissions from energy used to capture and use VAM ($PE_{ME}$)
= (4,769 MWh/year x 0.9747 $tCO_2e$/MWh) + (300 GJ/year x 0.0598 $tCO_2e$/GJ) = 4,666 $tCO_2e$/year

***Combined Project***

**$PE_{ME}$:** 1,339 $tCO_2e$/year + 4,666 $tCO_2e$/year = **6,005 $tCO_2e$/year**

| Project Component | $PE_{ME}$ ($tCO_2e$/year) |
|---|---|
| CMM-to-power/heat | 1,339 |
| VAM-to-heat | 4,666 |
| Combined CMM-to-power/heat and VAM-to-heat | 6,005 |

***<u>Combustion emissions from use of captured methane</u>***

**$PE_{MD}$: Project emissions from methane destroyed**

$PE_{MD} = (MD_{OX} + MD_{ELEC}) \times EF_{CH4}$ **(3)**

$MD_{OX} = MM_{OX} \times Eff_{OX}$ **(4)**

$MD_{ELEC} = MM_{ELEC} \times Eff_{ELEC}$ **(5)**

***CMM Project Component***

| | |
|---|---|
| Operating hours of gas engines: | 5,694 hours/year (old); 8,322 hours/year (new) |
| Methane destruction per gas engine: | 153 $m^3$ $CH_4$/engine/hour[4] |
| Number of gas engines installed: | 10 engines (5 old; 5 new) |
| Density of methane: | 0.67 $kg/m^3$ |
| $Eff_{ELEC}$: | 99.5% |
| $EF_{CH4}$: | 2.75 $tCO_2/tCH_4$ |

Methane sent to power plant ($MM_{ELEC}$)
= (5 engines x 5,694 hours/year + 5 engines x 8,322 hours/year) x 153 $m^3$ $CH_4$/engine/hour x 0.67 $kg/m^3$ $CH_4$ x 1 t/1000 kg = 7,184 $tCH_4$/year

Methane destroyed through power generation ($MD_{ELEC}$)
= 7,184 $tCH_4$/year x 0.995 = 7,148 $tCH_4$/year

Project emissions from electricity production ($PE_{MD}$)
= 7,148 $tCH_4$/year x 2.75 $tCO_2/tCH_4$ = 19,657 $tCO_2e$/year

***VAM Project Component***

| | |
|---|---|
| Operating hours of oxidizer: | 8,322 hours/year |
| Methane destruction per oxidizer unit: | 663 $m^3$ $CH_4$/oxidizer/hour[5] |
| Number of oxidizer units installed: | 2 |

[4] 153 $m^3$ $CH_4$/engine/hour = engine capacity / engine efficiency / net caloric value of $CH_4$ = 0.5 MW/engine x 1000 kW/MW x 1/0.35 x 1/33.7 $MJ/m^3$ x 3.6 MJ/kWh

[5] 663 $m^3$ $CH_4$/oxidizer/hour = oxidizer capacity x average VAM $CH_4$ concentration = 169,875 $m^3$ air/hour x 0.0039

Density of methane: $0.67\ kg/m^3$
$Eff_{OX}$: 96%
$EF_{CH4}$: $2.75\ tCO_2/tCH_4$

Methane sent to oxidizers ($MM_{OX}$)
= 2 oxidizer units x 8,322 hours/year x 663 $m^3$ $CH_4$/oxidizer/hour x 0.67 $kg/m^3$ $CH_4$ x 1 t/1000 kg
= 7,393 $tCH_4$/year

Methane destroyed through flameless oxidation ($MD_{OX}$)
= 7,393 $tCH_4$/year x 0.96 = 7,097 $tCH_4$/year

Project emissions from flameless oxidation ($PE_{MD}$)
= 7,097 $tCH_4$/year x 2.75 $tCO_2/tCH_4$ = 19,517 $tCO_2e$/year

***Combined Project***

**$PE_{MD}$:** 19,657 $tCO_2e$/year + 19,517 $tCO_2e$/year = **39,174 $tCO_2e$/year**

| Project Component | $PE_{MD}$ ($tCO_2e$/year) |
|---|---|
| CMM-to-power/heat | 19,657 |
| VAM-to-heat | 19,517 |
| Combined CMM-to-power/heat and VAM-to-heat | 39,174 |

***<u>Un-combusted methane from project activity</u>***

**$PE_{UM}$: Project emissions from un-combusted methane**

$$PE_{UM} = [MM_{ELEC} \times (1 - Eff_{ELEC}) + MM_{OX} \times (1 - Eff_{OX})] \times GWP_{CH4} \quad \textbf{(6)}$$

From above:

$Eff_{ELEC}$: 99.5%
$MM_{ELEC}$: 7,184 $tCH_4$/year
$Eff_{OX}$: 96%
$MM_{OX}$: 7,393 $tCH_4$/year
$GWP_{CH4}$: 21 $tCO_2e/tCH_4$

***CMM Project Component***

$PE_{UM} = [MM_{ELEC} \times (1 - Eff_{ELEC})] \times GWP_{CH4}$
= [7,184 $tCH_4$/year x (1 – 0.995)] x 21 $tCO_2e/tCH_4$ = 754 $tCO_2e$/year

***VAM Project Component***

$PE_{UM} = [MM_{OX} \times (1 - Eff_{OX})] \times GWP_{CH4}$
= [7,393 $tCH_4$/year x (1 – 0.96)] x 21 $tCO_2e/tCH_4$ = 6,210 $tCO_2e$/year

***Combined Project***

**$PE_{UM}$** = [7,184 $tCH_4$/year x (1 – 0.995) + 7,393 $tCH_4$/year x (1 – 0.96)] x 21 $tCO_2e/tCH_4$ = **6,964 $tCO_2e$/year**

| Project Component | $PE_{UM}$ ($tCO_2e$/year) |
|---|---|
| CMM-to-power/heat | 754 |
| VAM-to-heat | 6,210 |
| Combined CMM-to-power/heat and VAM-to-heat | 6,964 |

***<u>Total project emissions</u>***

$$PE_y = PE_{ME} + PE_{MD} + PE_{UM} \quad \textbf{(1)}$$

| Project Component | $PE_{ME}$ ($tCO_2e$/year) | $PE_{MD}$ ($tCO_2e$/year) | $PE_{UM}$ ($tCO_2e$/year) | $PE_y$ ($tCO_2e$/year) |
|---|---|---|---|---|
| CMM-to-power/heat | 1,339 | 19,657 | 754 | 21,750 |
| VAM-to-heat | 4,666 | 19,517 | 6,210 | 30,393 |
| Combined CMM-to-power/heat and VAM-to-heat | 6,005 | 39,174 | 6,964 | 52,143 |

### 6.5.3 Baseline Emissions

The baseline emissions are calculated based on equation (7) in section 6.4.3.2.

$$BE_y = BE_{MD,y} + BE_{MR,y} + BE_{Use,y} \quad \textbf{(7)}$$

***<u>Methane destruction in the baseline</u>***

**$BE_{MD,y}$: Baseline emissions from destruction of methane in the baseline scenario**

$$BE_{MD,y} = EF_{CH4} \times CMM_{BLi,y} \quad \textbf{(8)}$$

***CMM Project Component***

| | |
|---|---|
| Operating hours of gas engines: | 5,694 hours/year |
| Methane destruction per gas engine: | 153 $m^3$ $CH_4$/engine/hour[6] |
| Number of gas engines installed: | 5 engines |
| Density of methane: | 0.67 $kg/m^3$ |
| $Eff_{ELEC}$: | 99.5% |
| $EF_{CH4}$: | 2.75 $tCO_2/tCH_4$ |

[6] 153 $m^3$ $CH_4$/engine/hour = engine capacity / engine efficiency / net caloric value of $CH_4$ = 0.5 MW/engine x 1000 kW/MW x 1/0.35 x 1/33.7 $MJ/m^3$ x 3.6 MJ/kWh

CMM destroyed in baseline
= 5 engines x 153 $m^3$ $CH_4$/engine/hour x 5,694 hours/year x 0.67 kg/$m^3$ x 1 t/1,000 kg x 0.995 = 2,904 $tCH_4$/year

Total baseline emissions from methane destroyed ($BE_{MD,y}$)
= 2.75 $tCO_2/tCH_4$ x 2,904 $tCH_4$/year = 7,986 $tCO_2e$/year

***VAM Project Component***

VAM destroyed in baseline ($VAM_{BLi,y}$) = 0 $tCH_4$/year (see Section 6.4.3)

Total baseline emissions from methane destroyed ($BE_{MD,y}$)
= 0 $tCO_2e$/year

***Combined Project***

**$BE_{MD}$** = 7,986 $tCO_2e$/year + 0 $tCO_2e$/year = **7,986 $tCO_2e$/year**

| **Project Component** | **$BE_{MD,y}$ ($tCO_2e$/year)** |
|---|---|
| CMM-to-power/heat | 7,986 |
| VAM-to-heat | 0 |
| Combined CMM-to-power/heat and VAM-to-heat | 7,986 |

***Methane released into the atmosphere***

**$BE_{MR,y}$: Baseline emissions from release of methane into the atmosphere that is avoided by the project activity**

$$BE_{MRy} = GWP_{CH4} \times [\sum_i (CMM_{PJi,y} - CMM_{BLi,y}) + \sum_i (VAM_{PJi,y} - VAM_{BLi,y})] \qquad \textbf{(9)}$$

From above:

CMM destroyed in project ($CMM_{PJi,y}$): 7,148 $tCH_4$/year[7]
CMM destroyed in baseline ($CMM_{BLi,y}$): 2,904 $tCH_4$/year
VAM destroyed in project ($VAM_{PJi,y}$): 7,097 $tCH_4$/year[8]
VAM destroyed in baseline ($VAM_{BL,I,y}$): 0 $tCH_4$/year
$GWP_{CH4}$: 21 $tCO_2e/tCH_4$

***CMM Project Component***

CMM emissions avoided by project ($BE_{MRy}$)
= (7,148 $tCH_4$/year – 2,904 $tCH_4$/year) x 21 $tCO_2e/tCH_4$ = 89,124 $tCO_2e$/year

[7] $CMM_{PJi,y}$ = $MD_{ELEC}$ from calculation of $PE_{MD}$
[8] $VAM_{PJi,y}$ = $MD_{OX}$ from calculation of $PE_{MD}$

***VAM Project Component***

VAM emissions avoided by project ($BE_{MRy}$)
= (7,097 $tCH_4$/year – 0 $tCH_4$/year) x 21 $tCO_2e/tCH_4$ = 149,037 $tCO_2e$/year

***Combined Project***

$\mathbf{BE_{MRy}}$ = 89,124 $tCO_2e$/year + 149,037 $tCO_2e$/year = **238,161 $tCO_2e$/year**

| Project Component | $BE_{MR,y}$ ($tCO_2e$/year) |
|---|---|
| CMM-to-power/heat | 89,124 |
| VAM-to-heat | 149,037 |
| Combined CMM-to-power/heat and VAM-to-heat | 238,161 |

***Emissions from power/heat generation replaced by project***

**$BE_{Use,y}$: Baseline emissions from the production of power and heat**[9]

$$PBE_{Use,y} = GEN_y \times EF_{ELEC} + HEAT_y \times EF_{HEAT} \quad \textbf{(16)}$$

***CMM Project Component***

Number of gas engines: 10 engines (5 old; 5 new)
Gas engine estimated performance: 0.5 MW
Operating hours of gas engines: 5,694 hours/year (old); 8,322 hours/year (new)
$EF_{ELEC}$: 0.9747 $tCO_2e$/MWh
Gas engine waste heat generation: 0.4629 GJ/hour[10]
$EF_{HEAT}$: 0.095 $tCO_2e$/GJ[11]

Electricity generated by gas engines
= 5 engines x 0.5 MW/engine x 5,694 hours/year + 5 engines x 0.5 MW/engine x 8,322 hours/year = 35,040 MWh/year

Emissions displaced by electricity generated by gas engines ($PBE_{Use,y}$)
= 35,040 MWh/year x 0.9747 $tCO_2e$/MWh = 34,153 $tCO_2e$/year

[9] Actual heat output from gas engines and oxidizers is likely to be higher, but a heat utilization rate of 30% has been conservatively assumed for both technologies in case facilities in the vicinity of the equipment sites do not require the total heat output.
[10] = engine gas utilization x net caloric value of methane x engine heat efficiency x share of gas engine heat use = 153 $m^3CH_4$/hour x 33.7 $MJ/m^3$ x 0.3 x 1 GJ/1,000 MJ x 0.3
[11] = emission factor of coal x 1/boiler efficiency = 25.8 tC/TJ x 1/1.00 x 44 $tCO_2$/12 tC x 1 TJ/1,000 GJ

Heat generated by gas engines
= 5 engines x 0.4629 GJ/hour x 5,694 hours/year + 5 engines x 0.4629 GJ/hour x 8,322 hours/year = 32,440 GJ/year

Emissions displaced by heat generated by gas engines ($PBE_{Use,y}$)
= 32,440 GJ/year x 0.095 $tCO_2e$/GJ = 3,082 $tCO_2e$/year

Total emissions from production of power and heat from the CMM-fueled power plant ($PBE_{USE,y}$)
= 34,153 $tCO_2e$/year + 3,082 $tCO_2e$/year = 37,235 $tCO_2e$/year

***VAM Project Component***

| | |
|---|---|
| Number of oxidizer units: | 2 units |
| Oxidizer heat generation: | 4.2 GJ/hour[12] |
| Operating hours of oxidizers: | 8,322 hours/year |
| $EF_{HEAT}$: | 0.095 $tCO_2e$/GJ[13] |

Electricity generated by oxidizers
= 0 MWh/year

Emissions displaced by electricity generated by oxidizers ($PBE_{Use,y}$)
= 0 $tCO_2$/year

Heat generated by oxidizers
= 2 oxidizers x 4.2 GJ/hour x 8,322 hours/year = 69,905 GJ/year

Emissions displaced by heat generated by oxidizers ($PBE_{Use,y}$)
= 69,905 GJ/year x 0.095 $tCO_2e$/GJ = 6,641 $tCO_2e$/year

Total emissions from production of power and heat from the VAM oxidation units ($PBE_{USE,y}$)
= 0 $tCO_2e$/year + 6,641 $tCO_2e$/year = 6,641 $tCO_2e$/year

***Combined Project***

**$PBE_{Use,y}$** = 34,153 $tCO_2e$/year + 3,082 $tCO_2e$/year + 0 $tCO_2e$/year + 6,641 $tCO_2e$/year = **43,876 $tCO_2e$/year**

| **Project Component** | **$BE_{Use,y}$ ($tCO_2e$/year)** |
|---|---|
| CMM-to-power/heat | 37,235 |
| VAM-to-heat | 6,641 |
| Combined CMM-to-power/heat and VAM-to-heat | 43,876 |

[12] = heat recovered per unit x share of oxidizer heat used = 14GJ/hour x 0.3
[13] = emission factor of coal x 1/boiler efficiency = 25.8 tC/TJ x 1/1.00 x 44 $tCO_2$/12 tC x 1 TJ/1,000 GJ

***Total baseline emissions***

$BE_y = BE_{MD,y} + BE_{MR,y} + BE_{Use,y}$ ***(7)***

| **Project Component** | **$BE_{MD,y}$ ($tCO_2e$/year)** | **$BE_{MR,y}$ ($tCO_2e$/year)** | **$BE_{Use,y}$ ($tCO_2e$/year)** | **$BE_y$ ($tCO_2e$/year)** |
|---|---|---|---|---|
| CMM-to-power/heat | 7,986 | 89,124 | 37,235 | 134,345 |
| VAM-to-heat | 0 | 149,037 | 6,641 | 155,678 |
| Combined CMM-to-power/heat and VAM-to-heat | 7,986 | 238,161 | 43,876 | 290,023 |

### 6.5.4 Leakage

As determined in Section 6.4, leakage emissions are zero.

### 6.5.5 Emission Reductions

$ER_y = BE_y - PE_y - LE_y$ **(19)**

| **Project Component** | **$BE_y$:Total baseline emissions ($tCO_2e$)** | **$PE_y$: Total project emissions ($tCO_2e$)** | **$LE_y$: Total leakage emissions ($tCO_2e$)** | **$ER_y$: Total emission reductions ($tCO_2e$)** |
|---|---|---|---|---|
| CMM-to-power/heat | 134,345 | 21,750 | 0 | **112,592** |
| VAM-to-heat | 155,678 | 30,393 | 0 | **125,285** |
| Combined CMM-to-power/heat and VAM-to-heat | 290,023 | 52,143 | 0 | **237,880** |

A summary of the ex-ante estimation of emission reductions for the combined project is presented in Exhibit 6-13.

| **Year** | **$BE_y$:Total baseline emissions ($tCO_2e$)** | **$PE_y$: Total project emissions ($tCO_2e$)** | **$LE_y$: Total leakage emissions ($tCO_2e$)** | **$ER_y$: Total emission reductions ($tCO_2e$)** |
|---|---|---|---|---|
| Year 1 | 290,023 | 52,143 | 0 | 237,880 |
| Year 2 | 290,023 | 52,143 | 0 | 237,880 |
| Year 3 | 290,023 | 52,143 | 0 | 237,880 |
| Year 4 | 290,023 | 52,143 | 0 | 237,880 |
| Year 5 | 290,023 | 52,143 | 0 | 237,880 |
| Year 6 | 290,023 | 52,143 | 0 | 237,880 |
| Year 7 | 290,023 | 52,143 | 0 | 237,880 |
| Year 8 | 290,023 | 52,143 | 0 | 237,880 |
| Year 9 | 290,023 | 52,143 | 0 | 237,880 |
| Year 10 | 290,023 | 52,143 | 0 | 237,880 |
| **Total** | **2,900,230** | **521,430** | **0** | **2,378,800** |

**Exhibit 6-13: Total Emission Reductions for Combined Project**

## 6.6 Conclusions

Using ACM0008 as an emissions reduction calculation protocol, it is estimated that current emissions from Hebi Mine No.6 are 290,023 $tCO_2e$ per year. If in-seam methane is drained to power electric generators and VAM is captured and utilized for heating purposes, total emissions are estimated to drop to 52,143 $tCO_2e$. Total potential project emission reductions would equal 237,880 $tCO_2e$ per year, equivalent to removing 42,000 cars from the road.

It is worth noting again that the use of ACM0008 does not guarantee approval of the proposed projects by the CDM EB; its application is meant only as an illustration of the project's potential to generate emission reductions. If a carbon finance mechanism is pursued for the project, further due diligence on the part of the project developer should include an investment analysis and consider, among other things, the evolving regulatory framework in China and the effect of any new regulations on project additionality.

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# SECTION 7

# Capital and Operating Costs

# Economic and Financial Analyses

# SECTION 7 CONTENTS

# SECTION 7 EXHIBITS

## 7.1 Background

Hebi Mine No.6 currently drains an average of approximately 8.4 million $m^3$ of coal mine methane (100% $CH_4$) each year and uses 5.76 million $m^3$ of the gas to produce half of the mine's annual electricity needs. It is proposed in this feasibility study that upgrading the mine's methane drainage systems and techniques, would result in a 25% increase in methane drainage to 10.5 million $m^3$ per year. The following sections examine the operating costs and financial benefits of the several options that are available to fully utilize both the current gas stream and the proposed increased gas stream.

## 7.2 Capital and Operating Costs

The major costs associated with the proposed project are:

- Methane drainage upgrading - new drilling techniques, a new drainage pipeline system, training on the use of associated new machinery
- New Chinese electric generators
- New non-Chinese electric generators

### 7.2.1 Cost of Methane Drainage Recommendations

Pursuant to the recommendations in Section 4.9, the following components will contribute to the capital costs of upgrading methane drainage drilling techniques and the drainage pipeline system:

- Directional drilling equipment and training;
- HDPE pipe fusion equipment and training;
- Pipeline integrity and monitoring system.

Because the methane drainage recommendations will actually displace the amount of current drilling, including the overlying drilling galleries developed for gob degasification drilling, over-all methane drainage operating costs, or in particular, the drilling costs associated with the recommended directional drilling systems, will be less than or similar to current expenses.

#### 7.2.1.1 Directional Drilling Equipment and Training

Two directional drilling systems are recommended to develop the proposed new method of drilling cross-panel boreholes in Hebi Mine No.6. Approximately 80 drill stations per panel will be needed, with 3 tangential boreholes drilled from each drill station, for a total of 240 boreholes per panel. The directional drilling systems will also be needed for drilling three horizontal gob boreholes per longwall panel, in advance of mining. The two drilling units would be shared among the two mining districts (each operating up to two longwalls).

The estimated costs for all equipment (drills and downhole equipment) and including directional drilling training, total $3,482,000 and are presented in Exhibit 7-1.

| Description | | Unit Price | Unit | Quantity | Total Cost |
|---|---|---|---|---|---|
| **1. Longhole Directional Drill** | | | | | |
| | a. Drill and Power and Control Unit | $650,000 | package | 2 | $1,300,000 |
| | b. Spare Parts | $80,000 | package | 2 | $160,000 |
| **2. Drill Rods** | | | | | |
| | a. Non-Magnetic Drill Rods | $7,000 | Rod | 4 | $28,000 |
| | b. Drill Rods MECCA, 3m | $500 | Rod | 800 | $400,000 |
| **3. Downhole Motor** | | | | | |
| | a. 5/6 Stage "N" Motor | $30,000 | package | 4 | $120,000 |
| | b. Subs / Swivel, etc. | $10,000 | package | 4 | $40,000 |
| | c. Spare U-Joints and Bearings | $10,000 | package | 3 | $30,000 |
| | d. Fishing Tools | $10,000 | package | 2 | $20,000 |
| | e. Over-core Rods | $250 | package | 400 | $100,000 |
| **4. Survey Tools** | | | | | |
| | a. MWD Downhole Survey Tool | $350,000 | package | 2 | $700,000 |
| | b. Ancillary Equipment and Spare Parts | $50,000 | package | 2 | $100,000 |
| **5. Miscellaneous Items** | | | | | |
| | a. Drill Bits | $3,000 | pc | 20 | $60,000 |
| | b. Hole Openers | $6,000 | pc | 6 | $36,000 |
| | c. Miscellaneous Tools and Equipment | $30,000 | package | 2 | $60,000 |
| | d. Wellhead Equipment (Initial Boreholes) | $3,000 | package | 6 | $18,000 |
| **7. Other** | | | | | |
| | a. Shipping | $50,000 | est. | 1 | $50,000 |
| | b. Training and Technical Support | $10,000 | week | 26 | $260,000 |
| | | | | **TOTAL (USD):** | **$3,482,000** |

**Exhibit 7-1: Estimated costs for 2 directional drilling units and training**

### 7.2.1.2 HDPE Fusion Equipment, Monitoring and Safety Equipment and Training

Two sets of HDPE pipe fusion equipment, one dedicated to each district, are recommended, along with training on use of the equipment. One large diameter and one small diameter fusion unit is recommended per set. Under appropriate conditions, the fusion of individual sections of pipe can be conducted underground (in the U.S. this takes place in intake air courses), or large sections can be fused at the surface and hoisted or dragged underground. Equipment for the installation of a pipeline integrity system and provisions for monitoring the complete drainage system are also included.

Exhibit 7-2 summarizes estimated costs for the pipe fusion equipment and training, and includes supplies for an initial 2,000 m of pipeline, along with pipeline integrity and monitoring systems. Total estimated costs are $711,000. Hebi Mine No.6 should source Chinese suppliers for future orders of pipe, pipeline integrity and monitoring components, and provisions.

| Description | | Unit Price | Unit | Quantity | Total Cost |
|---|---|---|---|---|---|
| 1. Fusion Equipment | | | | | |
| | a. Fusion Machine (100 mm - 150 mm) | $40,000 | package | 2 | $80,000 |
| | b. Fusion Machine (200 mm - 400 mm) | $50,000 | package | 2 | $100,000 |
| 2. HDPE pipe for Training | | | | | |
| | a. 200 mm SDR 17 | $25 | meter | 2000 | $50,000 |
| | b. 300 mm SDR 17 | $60 | meter | 2000 | $120,000 |
| | c. assorted fittings | $5,000 | lot | 10 | $50,000 |
| 3. Pipeline Equipment | | | | | |
| | a. Integrity System | $6 | meter | 4000 | $24,000 |
| | b. Pneumatic Valves | $5,000 | Unit | 25 | $125,000 |
| | c. Gas/Water Separators | $3,600 | Unit | 5 | $18,000 |
| | d. Monitoring Meter Runs | $6,000 | Unit | 4 | $24,000 |
| | e. Assorted fittings | $5,000 | lot | 10 | $50,000 |
| 4. Other | | | | | |
| | a. Shipping | $30,000 | est. | 1 | $30,000 |
| | b. Technical Support and Training | $10,000 | week | 4 | $40,000 |
| | | | | **TOTAL (USD):** | **$711,000** |

**Exhibit 7-2: Estimated costs for fusion equipment and training**

### 7.2.2 Gathering System Replacement Cost

The existing gathering system consists of 6000 meters of 200 mm steel pipe, and 6000 meters of 300 mm steel pipe. The cost estimate for training, fusing equipment, and HDPE pipe for training purposes (2000 meters of 200 mm pipe, and 2000 meters of 300 mm pipe), is estimated to be $711,000 (Exhibit 7-2). 2000 meters of each of the 200 mm and 300 mm pipe will be replaced during the training period, including pipeline ancillary equipment. 4000 meters of each will need to be replaced after the training period is over. The cost of this HDPE pipe is $25 per meter for 200 mm pipe, $60 per meter for 300 mm pipe, and $60 per meter for ancillary equipment, or an additional $580,000, for a total gathering system replacement cost of $1,291,000.

### 7.2.3 Cost of Electric Power Generators

Five Chinese made 500kW Shengdong reciprocating electric generators currently provide half of the mine's electrical needs, using 15,800 $m^3$ of methane (100% $CH_4$). To fully utilize the current production of 23,000 $m^3$ or the estimated 28,750 $m^3$ of increased production after upgrading the methane drainage systems, it is necessary to add new generators to the current power plant. These generators could be similar Chinese made generators, or non Chinese sourced generators which tend to require less maintenance and hence have longer run-times.

Chinese suppliers quote the cost of new 500 kW Shengdong generator sets, as $145,000 (see section 7.5.1 - Appendix A). Two models especially designed to produce electricity from CMM gas streams are available. Model number 500GF1-2RW operates on input gas streams with $CH_4$ concentrations of 9-25%, while model number 500GF1-3RW operates on input streams with greater than 25% $CH_4$ concentration. The five existing generator sets are the former model, and will need to be converted for use with the improved quality gas stream resulting from the proposed methane drainage improvements. A cost of $10,000 to make the conversion has been assumed.

Additional costs associated with the purchase and installation of the generators include heat recovery equipment, transportation, facilities to house new generators (pad, shed, etc.), engineering, and commissioning. The heat recovery equipment is estimated to cost an additional $100,000, while equipment suppliers recommend estimating other additional costs at 50% of the generator set purchase price. Based on these numbers, the Shengdong generator set metrics are:

- $290 per kW to purchase a generator
- $200 per kW for heat recovery equipment
- $145 per kW to install all equipment
- Total cost to purchase and install a Shengdong generator is $635/kW, or $317,500 for a 500 kW generator.

Generator sets with reported higher run times than the Shengdong generator sets, sourced from alternate manufacturers such as Caterpillar, Cummins, and Jenbacher, were evaluated. The cost of these new generator sets, based on recent quotes for similar projects, has been estimated at $739/kW to purchase and install.

## 7.3 Economic Cash Flow Analyses

Five cases, reflecting different methods of utilizing drained CMM from Hebi Mine No.6 were evaluated through cash flow analyses:

- Base Case - Current situation at the mine, where five Chinese made electric generators use approximately 69% of drained methane.
- Case 1 - Installing more Chinese made electric generators to use all of the CMM currently drained by the mine.
- Case 2 - Installing more Chinese made electric generators to use all of the increased CMM drained by the mine as a result of the proposed drainage upgrades.
- Case 3 - Installing a mixture of extra electric generators, (Chinese and alternatives) to use all of the increased CMM volumes.
- Case 4 - Installing extra electric generators from non-Chinese sources only, to use all of the increased CMM volumes.

### 7.3.1 Economic Assumptions

**Source of Revenue**

The generation of power at the mine site, results in savings by avoiding power purchases from the grid. It is estimated that CMM produced by current and proposed drainage methods can be fully utilized. 2007 methane production figures, supplied by mine personnel, report that an average utilization of 15,800 $m^3$ per day of methane resulted in power generation able to supply 50% of Hebi Mine No.6's power requirement. This implies that 31,600 $m^3$ per day would be able to supply 100% of the mine’s power requirement. The modeling projections of the proposed methane drainage upgrades estimate an increase in methane production to 28,750 $m^3$ per day. All of the extra produced methane can be used to feed new generators and with the increased power generation be able to supply up to 91% of Hebi Mine No.6's power requirements.

**Avoided Power Cost**

Electric power in the Hebi region is sold to residential, industrial and commercial customers at different tariffs ranging from RMB 0.332/kWh to RMB 0.492/kWh ($0.049/kWh to $0.073/kWh). Data supplied by mine staff indicate a power purchase price of $0.0547/kWh, and this is the figure that has been assumed in the economics.

**In Mine Drainage Drilling Assumptions**

The current pre-mining drainage technique consists of drilling 140 meters of cross measure boreholes at 2 meter spacing. For each 1000 m longwall panel, this amounts to 70,000 m of borehole. The proposed new directional drilling technique will require drilling 420 m of borehole every 12 meters, or 35,000 meters of hole per panel. The estimated cost to amortized new equipment purchase and training is $8 per meter of hole drilled (estimate supplied by expert U.S. directional drilling contractor), and assuming a sunk cost for the existing cross measure technique of $4 per meter drilled, the actual cost of drilling will not change.

**Other Assumptions**

In all cases, capital and operating cost escalation is taken to be three percent. Other case specific assumptions will be detailed below in each case description.

## 7.4 Incremental Economics

Incremental economics is a way of comparing one project with another by subtracting their economic results. This method of economic analysis is used in situations when a decision among mutually exclusive projects is necessary. Incremental economics are performed by subtracting the project with a lower capital expense from the project with a larger capital expense. In this way, the economics of the incremental capital expense can be analyzed.

For the Hebi Mine No. 6 economics, five individual economic analyses, described in Section 7.3 were performed. From these five individual economic cashflows, four different incremental economic analyses were carried out and these are discussed in detail in later sections.

In each of the five individual cases, economic cashflow, costs and expenses were escalated at 3% per year, and each kWh of power generated results in a savings (revenue) of $0.0547/kWh in avoided power purchases from the grid. The matrix presented in Exhibit 7-3 summarizes the assumptions of the economics.

### 7.4.1 Base Case

The base case cash flow analysis examines the economics of the current methane drainage and electricity generation scenario at Hebi Mine No. 6.

- Production of 115,000 $m^3$ per day of drained gas, of which 20% is methane (23,000 $m^3$ of 100% $CH_4$), is not fully utilized by the existing power generation facilities.
- 70,000 meters per year of cross measure drainage boreholes are drilled at a cost of $4 per meter.
- Five Shengdong 500 kW generators operate at 35% efficiency at a 100% load factor and run 65% of the time resulting in average power generation capacity of 1.63 MW.
- The cost to operate the generators is estimated to be $0.03/kWh.

A cashflow for the Base Case is shown in Exhibit 7-4.

| Hebi Mine No. 6 Economics Input Parameter Grid | | Base Case | Case One | Case Two | Case Three | Case Four |
|---|---|---|---|---|---|---|
| Gross Gas Volume | (,000s $m^3$/day) | 115.00 | 115.00 | 57.50 | 57.50 | 57.50 |
| Methane Concentration | | 20% | 20% | 50% | 50% | 50% |
| Net Methane Volume | (,000s $m^3$/day) | 23.00 | 23.00 | 28.75 | 28.75 | 28.75 |
| Generator Description | | | | | | |
| Number Existing Gen Sets | | 5 | 5 | 5 | 5 | 5 |
| Capacity | kW | 500 | 500 | 500 | 500 | 500 |
| Efficiency | | 35% | 35% | 35% | 35% | 35% |
| Load Factor | | 100% | 100% | 100% | 100% | 100% |
| Run Time | | 65% | 65% | 65% | 65% | 65% |
| Number New Chinese Gen Sets | | | 5 | 8 | 5 | |
| Capacity | | | 500 | 500 | 500 | |
| Efficiency | | | 35% | 35% | 35% | |
| Load Factor | | | 100% | 100% | 100% | |
| Run Time | | | 65% | 65% | 65% | |
| Number New US Gen Sets | | | | | 2 | 5 |
| Capacity | | | | | 500 | 500 |
| Efficiency | | | | | 35% | 35% |
| Load Factor | | | | | 100% | 100% |
| Run Time | | | | | 95% | 95% |
| Capital Cost | | | | | | |
| New Chinese Gen Set | $/kW | - | 635 | 635 | 635 | |
| Upgrade of Old Gen Set (each) | $,000 | | | 10 | 10 | 10 |
| New US Gen Set | $/kW | | | | 739 | 739 |
| Gathering System Upgrade | $,000 | | | 1,291 | 1,291 | 1,291 |
| Cross Panel Drilling | | | | | | |
| Drilling Meterage | meters/yr | 70,000 | 70,000 | | | |
| Drilling Cost Rate | $/meter | 4 | 4 | | | |
| Directional Drilling | | | | | | |
| Drilling Meterage | meters/yr | | | 35,000 | 35,000 | 35,000 |
| Drilling Cost Rate | $/meter | | | 8 | 8 | 8 |
| Capital Escalation Factor | | 3% | 3% | 3% | 3% | 3% |
| Operating Cost | | | | | | |
| Existing Generator | $/kW | 0.030 | | | | |
| New Chinese Generator | $/kW | | 0.030 | 0.030 | 0.030 | |
| New US Generator | $/kW | | | | 0.030 | 0.030 |
| Operating Cost Esc. Factor | | 3% | 3% | 3% | 3% | 3% |
| Power Sales or Savings Price | | 0.0547 | 0.0547 | 0.0547 | 0.0547 | 0.0547 |
| Price Escalation Factor | | 3% | 3% | 3% | 3% | 3% |

**Exhibit 7-3: Economic Assumptions for Individual Cases**

### 7.4.2 Case One

- Production of 115,000 $m^3$/day of drained gas, of which 20% is methane, is fully utilized by the existing power generation facilities plus five additional Shengdong generator sets.
- Additional units, including heat recovery equipment, are purchased and installed at a cost of $635/kW.
- 70,000 meters per year of cross measure drainage boreholes are drilled at a cost of $4 per meter.
- The five existing and five additional Shengdong 500 kW generators operate at 35% efficiency at a 100% load factor and run 65% of the time resulting in average power generation capacity of 3.15 MW.
- The cost to operate the generators is estimated to be $0.03/kWh.

A cashflow for Case One is shown in Exhibit 7-5.

### 7.4.3 Case Two

- Implement the directional drilling drainage scheme, upgrade the gathering system from the old steel system to a new high density polyethylene (HDPE) system
- Production of 57,500 $m^3$/day of drained gas, of which 50% is methane (28,750 $m^3$ 100% $CH_4$), is fully utilized by the existing power generation facilities plus eight additional Shengdong generation units.
- Additional units, including heat recovery equipment, are purchased and installed at a cost of $635/kW.
- 35,000 meters per year of cross measure drainage boreholes are drilled at a cost of $8 per meter.
- The five existing and eight additional Shengdong 500 kW generators operate at 35% efficiency at a 100% load factor and run 65% of the time resulting in average power generation capacity of 3.94 MW.
- The cost to operate the generators is estimated to be $0.03/kWh.

A cashflow for Case Two is shown in Exhibit 7-6.

### 7.4.4 Case Three

- Implement the directional drilling drainage scheme, upgrade the gathering system from the old steel system to a new high density polyethylene (HDPE) system
- Production of 57,500 $m^3$ per day of drained gas, of which 50% is methane (28,750 $m^3$ 100% $CH_4$), is fully utilized by the existing power generation facilities plus five new Shengdong generators and two generators from an alternate manufacturer such as Caterpillar, Cummins, Jenbacher, etc. with reported higher run times.
- Shengdong generators are purchased at a cost of $635/kW, and alternate manufacturer generators are purchased at a cost of $739/kW. All units include heat recovery equipment.

- 35,000 meters per year of cross measure drainage boreholes are drilled at a cost of $8 per meter.
- The five existing and five additional Shengdong 500 kW generators operate with a 35% efficiency rating, a 100% load factor, and run 65% of the time. The two 500 kW generators from an alternate manufacturer have a reported performance of 35% efficiency, a 100% load factor, and can run 95% of the time. The total power generation capacity of all these generators in operation is 3.94 MW.
- The cost to operate the generators is assumed to be $0.03/kWh.

A cashflow for Case Three is shown in Exhibit 7-7.

### 7.4.5 Case Four

Implement the directional drilling drainage scheme, upgrade the gathering system from the old steel system to a new HDPE system, and purchase of five additional generator sets from an alternate manufacturer.

- Production of 57,500 $m^3$ per day of drainage gas, of which 50% is methane, is fully utilized by the existing power generation facilities plus five alternate manufacturer generators.
- Alternate manufacturer generators, including heat recovery equipment, are purchased at a cost of $739/kW and include heat recovery equipment.
- 35,000 meters per year of cross measure drainage boreholes are drilled at a cost of $8 per meter.
- The five existing Shengdong 500 kW generators operate with a 35% efficiency rating, a 100% load factor, and run 65% of the time. The five 500 kW generators from an alternate manufacturer have a reported performance of 35% efficiency, a 100% load factor, and can run 95% of the time. The total power generation capacity of all these generators in operation is 3.94 MW.
- The cost to operate the generators is estimated to be $0.03/kWh.

A cashflow for Case Four is shown in Exhibit 7-8.

**Hebi Mine No.6**
**Utilization of Drainage Gas for Power Generation**
**Base Case: Existing drainage system and utilization scheme**

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Year-------------------------> | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | Remainder | Total |
| Gas Production | $Mm^3$ | | 41.98 | 41.98 | 41.98 | 41.98 | 41.98 | 41.98 | 41.98 | 41.98 | 41.98 | 41.98 | 420 | 840 |
| Methane Production | $Mm^3$ | | 8.40 | 8.40 | 8.40 | 8.40 | 8.40 | 8.40 | 8.40 | 8.40 | 8.40 | 8.40 | 84 | 168 |
| Energy Production | GJ | | 284,142 | 284,142 | 284,142 | 284,142 | 284,142 | 284,142 | 284,142 | 284,142 | 284,142 | 284,142 | 2,841,418 | 5,682,836 |
| Energy Production | MWHr | | 78,928 | 78,928 | 78,928 | 78,928 | 78,928 | 78,928 | 78,928 | 78,928 | 78,928 | 78,928 | 789,283 | 1,578,566 |
| Energy Production | mmBTU | | 269,495 | 269,495 | 269,495 | 269,495 | 269,495 | 269,495 | 269,495 | 269,495 | 269,495 | 269,495 | 2,694,948 | 5,389,896 |
| Power Generation | MW | | 1.63 | 1.63 | 1.63 | 1.63 | 1.63 | 1.63 | 1.63 | 1.63 | 1.63 | 1.63 | 1.63 | 1.63 |
| Power Sales or Savings | $/kW | | 0.055 | 0.056 | 0.058 | 0.060 | 0.062 | 0.063 | 0.065 | 0.067 | 0.069 | 0.071 | 0.084 | 0.073 |
| Revenue | $,000 | | 778.65 | 802.01 | 826.07 | 850.86 | 876.38 | 902.67 | 929.75 | 957.65 | 986.38 | 1,015.97 | 11,996 | 20,923 |
| Operating Cost | $,000 | | 427.05 | 439.86 | 453.06 | 466.65 | 480.65 | 495.07 | 509.92 | 525.22 | 540.97 | 557.20 | 6,579 | 11,475 |
| Cashflow Before Capital Expenditures | | 9,448 | 351.60 | 362.15 | 373.02 | 384.21 | 395.73 | 407.61 | 419.83 | 432.43 | 445.40 | 458.76 | 5,417 | 9,448 |
| Capital Cost | $,000 | | | | | | | | | | | | | |
| Generators | | | - | - | - | - | - | - | - | - | - | - | - | - |
| Upgrade Gathering System | | | - | - | - | - | - | - | - | - | - | - | - | - |
| Drilling | | | 280 | 288 | 297 | 306 | 315 | 325 | 334 | 344 | 355 | 365 | 4,314 | 7,524 |
| Total Capital | | | 280 | 288 | 297 | 306 | 315 | 325 | 334 | 344 | 355 | 365 | 4,314 | 7,524 |
| Cashflow | | 1,924 | 71.60 | 73.75 | 75.97 | 78.24 | 80.59 | 83.01 | 85.50 | 88.06 | 90.71 | 93.43 | 1,103 | 1,924 |
| Discounted Cashflow | | | | | | | | | | | | | | |
| 10% | | | 68.27 | 63.93 | 59.86 | 56.05 | 52.48 | 49.14 | 46.02 | 43.09 | 40.35 | 37.78 | 268 | 785 |
| 15% | | | 66.77 | 59.80 | 53.56 | 47.97 | 42.97 | 38.48 | 34.47 | 30.87 | 27.65 | 24.77 | 142 | 569 |
| 20% | | | 65.37 | 56.11 | 48.16 | 41.33 | 35.48 | 30.45 | 26.14 | 22.44 | 19.26 | 16.53 | 78 | 440 |
| 25% | | | 64.05 | 52.77 | 43.49 | 35.83 | 29.53 | 24.33 | 20.05 | 16.52 | 13.61 | 11.22 | 45 | 356 |
| 30% | | | 62.80 | 49.76 | 39.42 | 31.24 | 24.75 | 19.61 | 15.54 | 12.31 | 9.75 | 7.73 | 27 | 300 |
| 40% | | | 60.52 | 44.52 | 32.76 | 24.10 | 17.73 | 13.04 | 9.60 | 7.06 | 5.19 | 3.82 | 10 | 228 |
| 50% | | | 58.46 | 40.15 | 27.57 | 18.93 | 13.00 | 8.93 | 6.13 | 4.21 | 2.89 | 1.98 | 4 | 186 |
| 75% | | | 54.13 | 31.86 | 18.75 | 11.04 | 6.50 | 3.82 | 2.25 | 1.32 | 0.78 | 0.46 | 1 | 132 |
| Internal Rate of Return | | | | | | | | | | | | | | |
| Efficiency | | | 35% | | | | 3.15 | | | | | | | |
| Implied Generating Capacity | MW | | 3.15 | | | | 2.50 | | | | | | | |
| Utilized Methane | $km^3/d$ | | 11.9 | | | | 1.63 | | | | | | | |
| Vented Methane | $km^3/d$ | | 11.1 | | | | | | | | | | | |

**Exhibit 7-4: Base Case Cashflow**

**Hebi Mine No.6**
**Utilization of Drainage Gas for Power Generation**
**Case One: Existing drainage system with additional Chinese generators**

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Year--------------------------> | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | Remainder | Total |
| Gas Production | $Mm^3$ | | 41.98 | 41.98 | 41.98 | 41.98 | 41.98 | 41.98 | 41.98 | 41.98 | 41.98 | 41.98 | 420 | 840 |
| Methane Production | $Mm^3$ | | 8.40 | 8.40 | 8.40 | 8.40 | 8.40 | 8.40 | 8.40 | 8.40 | 8.40 | 8.40 | 84 | 168 |
| Energy Production | GJ | | 284,142 | 284,142 | 284,142 | 284,142 | 284,142 | 284,142 | 284,142 | 284,142 | 284,142 | 284,142 | 2,841,418 | 5,682,836 |
| Energy Production | MWHr | | 78,928 | 78,928 | 78,928 | 78,928 | 78,928 | 78,928 | 78,928 | 78,928 | 78,928 | 78,928 | 789,283 | 1,578,566 |
| Energy Production | mmBTU | | 269,495 | 269,495 | 269,495 | 269,495 | 269,495 | 269,495 | 269,495 | 269,495 | 269,495 | 269,495 | 2,694,948 | 5,389,896 |
| Power Generation | MW | | 3.15 | 3.15 | 3.15 | 3.15 | 3.15 | 3.15 | 3.15 | 3.15 | 3.15 | 3.15 | 3.15 | 3.15 |
| Power Sales or Savings | $/kW | | 0.055 | 0.056 | 0.058 | 0.060 | 0.062 | 0.063 | 0.065 | 0.067 | 0.069 | 0.071 | 0.084 | 0.073 |
| Revenue | $,000 | | 1,511.08 | 1,556.41 | 1,603.11 | 1,651.20 | 1,700.74 | 1,751.76 | 1,804.31 | 1,858.44 | 1,914.19 | 1,971.62 | 23,280 | 40,603 |
| Operating Cost | $,000 | | 828.75 | 853.61 | 879.22 | 905.59 | 932.76 | 960.74 | 989.57 | 1,019.25 | 1,049.83 | 1,081.33 | 12,768 | 22,269 |
| Cashflow Before Capital Expenditures | $,000 | | 682.34 | 702.81 | 723.89 | 745.61 | 767.97 | 791.01 | 814.74 | 839.19 | 864.36 | 890.29 | 10,512 | 18,335 |
| Capital Cost | $,000 | | | | | | | | | | | | | |
| Generators | | | 1,618 | - | - | - | - | - | - | - | - | - | - | 1,618 |
| Upgrade Gathering System | | | - | - | - | - | - | - | - | - | - | - | - | - |
| Drilling | | | 280 | 288 | 297 | 306 | 315 | 325 | 334 | 344 | 355 | 365 | 4,314 | 7,524 |
| Total Capital | | | 1,898 | 288 | 297 | 306 | 315 | 325 | 334 | 344 | 355 | 365 | 4,314 | 9,141 |
| Cashflow | | 9,193 | (1,215.36) | 414.41 | 426.84 | 439.64 | 452.83 | 466.42 | 480.41 | 494.82 | 509.67 | 524.96 | 6,199 | 9,193 |
| Discounted Cashflow | | | | | | | | | | | | | | |
| 10% | | | (1,158.80) | 359.20 | 336.34 | 314.94 | 294.90 | 276.13 | 258.56 | 242.10 | 226.70 | 212.27 | 1,505 | 2,867 |
| 15% | | | (1,133.33) | 336.03 | 300.97 | 269.56 | 241.43 | 216.24 | 193.68 | 173.47 | 155.37 | 139.15 | 798 | 1,690 |
| 20% | | | (1,109.46) | 315.25 | 270.59 | 232.26 | 199.35 | 171.11 | 146.87 | 126.06 | 108.20 | 92.88 | 441 | 994 |
| 25% | | | (1,087.05) | 296.52 | 244.34 | 201.33 | 165.90 | 136.70 | 112.64 | 92.82 | 76.48 | 63.02 | 252 | 555 |
| 30% | | | (1,065.94) | 279.58 | 221.52 | 175.51 | 139.06 | 110.18 | 87.29 | 69.16 | 54.80 | 43.42 | 149 | 264 |
| 40% | | | (1,027.16) | 250.17 | 184.05 | 135.41 | 99.62 | 73.29 | 53.92 | 39.67 | 29.19 | 21.47 | 57 | (83) |
| 50% | | | (992.33) | 225.57 | 154.89 | 106.36 | 73.03 | 50.15 | 34.44 | 23.65 | 16.24 | 11.15 | 24 | (273) |
| 75% | | | (918.72) | 179.01 | 105.36 | 62.01 | 36.50 | 21.48 | 12.64 | 7.44 | 4.38 | 2.58 | 4 | (484) |
| Internal Rate of Return | | 36.9% | | | | | | | | | | | | |
| Efficiency | | | 35% | | | 3.153527 | | | | | | | | |
| Implied Generating Capacity | MW | | 3.15 | | | 5.05 | | | | | | | | |
| Utilized Methane | $km^3/d$ | | 23.0 | | | 3.15 | | | | | | | | |
| Vented Methane | $km^3/d$ | | - | | | | | | | | | | | |

**Exhibit 7-5: Case One Cashflow**

**Hebi Mine No.6**
**Utilization of Drainage Gas for Power Generation**
**Case Two: Upgraded gathering system with additional Chinese generators**

| Project Year-------------------------> | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | Remainder | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gas Production | $Mm^3$ | | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 210 | 420 |
| Methane Production | $Mm^3$ | | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 105 | 210 |
| Energy Production | GJ | | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 3,551,773 | 7,103,546 |
| Energy Production | MWHr | | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 986,604 | 1,973,207 |
| Energy Production | mmBTU | | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 3,368,685 | 6,737,369 |
| Power Generation | MW | | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 |
| Power Sales or Savings | $/kW | | 0.055 | 0.056 | 0.058 | 0.060 | 0.062 | 0.063 | 0.065 | 0.067 | 0.069 | 0.071 | 0.084 | 0.073 |
| Revenue | $,000 | | 1,888.85 | 1,945.52 | 2,003.88 | 2,064.00 | 2,125.92 | 2,189.70 | 2,255.39 | 2,323.05 | 2,392.74 | 2,464.52 | 29,101 | 50,754 |
| Operating Cost | $,000 | | 1,035.93 | 1,067.01 | 1,099.02 | 1,131.99 | 1,165.95 | 1,200.93 | 1,236.96 | 1,274.07 | 1,312.29 | 1,351.66 | 15,960 | 27,836 |
| Cashflow Before Capital Expenditures | $,000 | | 852.92 | 878.51 | 904.86 | 932.01 | 959.97 | 988.77 | 1,018.43 | 1,048.98 | 1,080.45 | 1,112.87 | 13,140 | 22,918 |
| Capital Cost | $,000 | | | | | | | | | | | | | |
| Generators | | | 2,502 | - | - | - | - | - | - | - | - | - | - | 2,502 |
| Upgrade Gathering System | | | 1,291 | - | - | - | - | - | - | - | - | - | - | 1,291 |
| Drilling | | | 280 | 288 | 297 | 306 | 315 | 325 | 334 | 344 | 355 | 365 | 4,314 | 7,524 |
| Total Capital | | | 4,073 | 288 | 297 | 306 | 315 | 325 | 334 | 344 | 355 | 365 | 4,314 | 11,317 |
| Cashflow | | 11,601 | (3,220.14) | 590.11 | 607.81 | 626.04 | 644.83 | 664.17 | 684.09 | 704.62 | 725.76 | 747.53 | 8,827 | 11,601 |
| Discounted Cashflow | | | | | | | | | | | | | | |
| 10% | | | (3,070.29) | 511.49 | 478.95 | 448.47 | 419.93 | 393.21 | 368.18 | 344.75 | 322.81 | 302.27 | 2,143 | 2,663 |
| 15% | | | (3,002.80) | 478.50 | 428.57 | 383.85 | 343.80 | 307.92 | 275.79 | 247.01 | 221.24 | 198.15 | 1,136 | 1,018 |
| 20% | | | (2,939.58) | 448.91 | 385.31 | 330.73 | 283.87 | 243.66 | 209.14 | 179.51 | 154.08 | 132.25 | 627 | 55 |
| 25% | | | (2,880.18) | 422.25 | 347.93 | 286.69 | 236.24 | 194.66 | 160.40 | 132.17 | 108.91 | 89.74 | 360 | (542) |
| 30% | | | (2,824.25) | 398.12 | 315.43 | 249.92 | 198.01 | 156.89 | 124.30 | 98.49 | 78.03 | 61.83 | 213 | (930) |
| 40% | | | (2,721.52) | 356.24 | 262.09 | 192.82 | 141.86 | 104.37 | 76.79 | 56.49 | 41.56 | 30.58 | 81 | (1,378) |
| 50% | | | (2,629.24) | 321.21 | 220.57 | 151.46 | 104.00 | 71.41 | 49.04 | 33.67 | 23.12 | 15.88 | 34 | (1,605) |
| 75% | | | (2,434.20) | 254.90 | 150.03 | 88.30 | 51.97 | 30.59 | 18.00 | 10.60 | 6.24 | 3.67 | 5 | (1,815) |
| Internal Rate of Return | | 20.4% | | | | | | | | | | | | |
| Efficiency | | | 35% | | | | | | | | | | | |
| Implied Generating Capacity | MW | | 3.94 | | | | | | | | | | | |
| Utilized Methane | $km^3/d$ | | 28.8 | | | | | | | | | | | |
| Vented Methane | $km^3/d$ | | - | | | | | | | | | | | |

**Exhibit 7-6: Case Two Cashflow**

**Hebi Mine No.6**
**Utilization of Drainage Gas for Power Generation**
**Case Three: Upgraded gathering system with additional Chinese and U.S. generators**

| Project Year-------------------------> | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | Remainder | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gas Production | $Mm^3$ | | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 210 | 420 |
| Methane Production | $Mm^3$ | | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 105 | 210 |
| Energy Production | GJ | | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 3,551,773 | 7,103,546 |
| Energy Production | MWHr | | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 986,604 | 1,973,207 |
| Energy Production | mmBTU | | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 3,368,685 | 6,737,369 |
| Power Generation | MW | | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 |
| Power Sales or Savings | $/kW | | 0.055 | 0.056 | 0.058 | 0.060 | 0.062 | 0.063 | 0.065 | 0.067 | 0.069 | 0.071 | 0.084 | 0.073 |
| Revenue | $,000 | | 1,888.85 | 1,945.52 | 2,003.88 | 2,064.00 | 2,125.92 | 2,189.70 | 2,255.39 | 2,323.05 | 2,392.74 | 2,464.52 | 29,101 | 50,754 |
| Operating Cost | $,000 | | 1,035.93 | 1,067.01 | 1,099.02 | 1,131.99 | 1,165.95 | 1,200.93 | 1,236.96 | 1,274.07 | 1,312.29 | 1,351.66 | 15,960 | 27,836 |
| Cashflow Before Capital Expenditures | $,000 | | 852.92 | 878.51 | 904.86 | 932.01 | 959.97 | 988.77 | 1,018.43 | 1,048.98 | 1,080.45 | 1,112.87 | 13,140 | 22,918 |
| Capital Cost | $,000 | | | | | | | | | | | | | |
| Generators | | | 2,273 | - | - | - | - | - | - | - | - | - | - | 2,273 |
| Upgrade Gathering System | | | 1,291 | - | - | - | - | - | - | - | - | - | - | 1,291 |
| Drilling | | | 280 | 288 | 297 | 306 | 315 | 325 | 334 | 344 | 355 | 365 | 4,314 | 7,524 |
| Total Capital | | | 3,844 | 288 | 297 | 306 | 315 | 325 | 334 | 344 | 355 | 365 | 4,314 | 11,088 |
| Cashflow | | 11,831 | (2,991.05) | 590.11 | 607.81 | 626.04 | 644.83 | 664.17 | 684.09 | 704.62 | 725.76 | 747.53 | 8,827 | 11,831 |
| Discounted Cashflow | | | | | | | | | | | | | | |
| 10% | | | (2,851.85) | 511.49 | 478.95 | 448.47 | 419.93 | 393.21 | 368.18 | 344.75 | 322.81 | 302.27 | 2,143 | 2,881 |
| 15% | | | (2,789.17) | 478.50 | 428.57 | 383.85 | 343.80 | 307.92 | 275.79 | 247.01 | 221.24 | 198.15 | 1,136 | 1,231 |
| 20% | | | (2,730.44) | 448.91 | 385.31 | 330.73 | 283.87 | 243.66 | 209.14 | 179.51 | 154.08 | 132.25 | 627 | 264 |
| 25% | | | (2,675.28) | 422.25 | 347.93 | 286.69 | 236.24 | 194.66 | 160.40 | 132.17 | 108.91 | 89.74 | 360 | (337) |
| 30% | | | (2,623.32) | 398.12 | 315.43 | 249.92 | 198.01 | 156.89 | 124.30 | 98.49 | 78.03 | 61.83 | 213 | (729) |
| 40% | | | (2,527.90) | 356.24 | 262.09 | 192.82 | 141.86 | 104.37 | 76.79 | 56.49 | 41.56 | 30.58 | 81 | (1,184) |
| 50% | | | (2,442.18) | 321.21 | 220.57 | 151.46 | 104.00 | 71.41 | 49.04 | 33.67 | 23.12 | 15.88 | 34 | (1,418) |
| 75% | | | (2,261.02) | 254.90 | 150.03 | 88.30 | 51.97 | 30.59 | 18.00 | 10.60 | 6.24 | 3.67 | 5 | (1,641) |
| Internal Rate of Return | | 21.9% | | | | | | | | | | | | |
| Efficiency | | | 35% | | | | | | | | | | | |
| Implied Generating Capacity | MW | | 3.94 | | | | | | | | | | | |
| Utilized Methane | $km^3/d$ | | 28.8 | | | | | | | | | | | |
| Vented Methane | $km^3/d$ | | - | | | | | | | | | | | |

**Exhibit 7-7: Case Three Cashflow**

**Hebi Mine No.6**
**Utilization of Drainage Gas for Power Generation**
**Case Four: Upgraded gathering system with U.S. generators**

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Year-------------------------> | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | Remainder | Total |
| Gas Production | $Mm^3$ | | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 20.99 | 210 | 420 |
| Methane Production | $Mm^3$ | | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 10.49 | 105 | 210 |
| Energy Production | GJ | | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 355,177 | 3,551,773 | 7,103,546 |
| Energy Production | MWHr | | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 98,660 | 986,604 | 1,973,207 |
| Energy Production | mmBTU | | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 336,868 | 3,368,685 | 6,737,369 |
| Power Generation | MW | | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 | 3.94 |
| Power Sales or Savings | $/kW | | 0.055 | 0.056 | 0.058 | 0.060 | 0.062 | 0.063 | 0.065 | 0.067 | 0.069 | 0.071 | 0.084 | 0.073 |
| Revenue | $,000 | | 1,888.85 | 1,945.52 | 2,003.88 | 2,064.00 | 2,125.92 | 2,189.70 | 2,255.39 | 2,323.05 | 2,392.74 | 2,464.52 | 29,101 | 50,754 |
| Operating Cost | $,000 | | 1,035.93 | 1,067.01 | 1,099.02 | 1,131.99 | 1,165.95 | 1,200.93 | 1,236.96 | 1,274.07 | 1,312.29 | 1,351.66 | 15,960 | 27,836 |
| Cashflow Before Capital Expenditures | $,000 | | 852.92 | 878.51 | 904.86 | 932.01 | 959.97 | 988.77 | 1,018.43 | 1,048.98 | 1,080.45 | 1,112.87 | 13,140 | 22,918 |
| Capital Cost | $,000 | | | | | | | | | | | | | |
| Generators | | | 1,852 | - | - | - | - | - | - | - | - | - | - | 1,852 |
| Upgrade Gathering System | | | 1,291 | - | - | - | - | - | - | - | - | - | - | 1,291 |
| Drilling | | | 280 | 288 | 297 | 306 | 315 | 325 | 334 | 344 | 355 | 365 | 4,314 | 7,524 |
| Total Capital | | | 3,423 | 288 | 297 | 306 | 315 | 325 | 334 | 344 | 355 | 365 | 4,314 | 10,667 |
| Cashflow | | 12,251 | (2,570.39) | 590.11 | 607.81 | 626.04 | 644.83 | 664.17 | 684.09 | 704.62 | 725.76 | 747.53 | 8,827 | 12,251 |
| Discounted Cashflow | | | | | | | | | | | | | | |
| 10% | | | (2,450.77) | 511.49 | 478.95 | 448.47 | 419.93 | 393.21 | 368.18 | 344.75 | 322.81 | 302.27 | 2,143 | 3,282 |
| 15% | | | (2,396.90) | 478.50 | 428.57 | 383.85 | 343.80 | 307.92 | 275.79 | 247.01 | 221.24 | 198.15 | 1,136 | 1,624 |
| 20% | | | (2,346.44) | 448.91 | 385.31 | 330.73 | 283.87 | 243.66 | 209.14 | 179.51 | 154.08 | 132.25 | 627 | 648 |
| 25% | | | (2,299.03) | 422.25 | 347.93 | 286.69 | 236.24 | 194.66 | 160.40 | 132.17 | 108.91 | 89.74 | 360 | 39 |
| 30% | | | (2,254.38) | 398.12 | 315.43 | 249.92 | 198.01 | 156.89 | 124.30 | 98.49 | 78.03 | 61.83 | 213 | (360) |
| 40% | | | (2,172.38) | 356.24 | 262.09 | 192.82 | 141.86 | 104.37 | 76.79 | 56.49 | 41.56 | 30.58 | 81 | (828) |
| 50% | | | (2,098.72) | 321.21 | 220.57 | 151.46 | 104.00 | 71.41 | 49.04 | 33.67 | 23.12 | 15.88 | 34 | (1,074) |
| 75% | | | (1,943.03) | 254.90 | 150.03 | 88.30 | 51.97 | 30.59 | 18.00 | 10.60 | 6.24 | 3.67 | 5 | (1,324) |
| Internal Rate of Return | | 25.4% | | | | | | | | | | | | |
| Efficiency | | | 35% | | | | | | | | | | | |
| Implied Generating Capacity | MW | | 3.94 | | | | | | | | | | | |
| Utilized Methane | $km^3/d$ | | 28.8 | | | | | | | | | | | |
| Vented Methane | $km^3/d$ | | - | | | | | | | | | | | |

**Exhibit 7-8: Case Four Cashflow**

### 7.4.6 Summary

Incremental economic analyses consisted of the following comparisons:

Case One v Base Case; Case Two v Case One; Case Three v Case One; Case Four – Case One

**Hebi Mine No.6**
**Utilization of Drainage Gas for Power Generation**
**Incremental Economics Summary**

| Incremental Economics: Case One and Base Case | | | | Internal Rate of Return | | | 29.1% | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Year-------------------------> | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | Remainder |
| **Case One** | | (1,215) | 414 | 427 | 440 | 453 | 466 | 480 | 495 | 510 | 525 | 6,199 |
| **Base Case** | | 72 | 74 | 76 | 78 | 81 | 83 | 85 | 88 | 91 | 93 | 1,103 |
| Incremental | | (1,287) | 341 | 351 | 361 | 372 | 383 | 395 | 407 | 419 | 432 | 5,095 |
| Discounted Cashflow | | | | | | | | | | | | |
| 10% | 2,083 | (1,227) | 295 | 276 | 259 | 242 | 227 | 213 | 199 | 186 | 174 | 1,237 |
| 15% | 1,121 | (1,200) | 276 | 247 | 222 | 198 | 178 | 159 | 143 | 128 | 114 | 656 |
| 20% | 554 | (1,175) | 259 | 222 | 191 | 164 | 141 | 121 | 104 | 89 | 76 | 362 |
| 25% | 199 | (1,151) | 244 | 201 | 166 | 136 | 112 | 93 | 76 | 63 | 52 | 208 |
| 30% | (35) | (1,129) | 230 | 182 | 144 | 114 | 91 | 72 | 57 | 45 | 36 | 123 |
| 40% | (312) | (1,088) | 206 | 151 | 111 | 82 | 60 | 44 | 33 | 24 | 18 | 47 |
| 50% | (459) | (1,051) | 185 | 127 | 87 | 60 | 41 | 28 | 19 | 13 | 9 | 20 |
| 75% | (615) | (973) | 147 | 87 | 51 | 30 | 18 | 10 | 6 | 4 | 2 | 3 |

| Incremental Economics: Case Two and Case One | | | | Internal Rate of Return | | | 8.5% | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Year-------------------------> | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | |
| **Case Two** | | (3,220) | 590 | 608 | 626 | 645 | 664 | 684 | 705 | 726 | 748 | 8,827 |
| **Case One** | | (1,215) | 414 | 427 | 440 | 453 | 466 | 480 | 495 | 510 | 525 | 6,199 |
| Incremental | | (2,005) | 176 | 181 | 186 | 192 | 198 | 204 | 210 | 216 | 223 | 2,628 |
| Discounted Cashflow | | | | | | | | | | | | |
| 10% | (204) | (1,911) | 152 | 143 | 134 | 125 | 117 | 110 | 103 | 96 | 90 | 638 |
| 15% | (672) | (1,869) | 142 | 128 | 114 | 102 | 92 | 82 | 74 | 66 | 59 | 338 |
| 20% | (938) | (1,830) | 134 | 115 | 98 | 85 | 73 | 62 | 53 | 46 | 39 | 187 |
| 25% | (1,097) | (1,793) | 126 | 104 | 85 | 70 | 58 | 48 | 39 | 32 | 27 | 107 |
| 30% | (1,194) | (1,758) | 119 | 94 | 74 | 59 | 47 | 37 | 29 | 23 | 18 | 63 |
| 40% | (1,294) | (1,694) | 106 | 78 | 57 | 42 | 31 | 23 | 17 | 12 | 9 | 24 |
| 50% | (1,332) | (1,637) | 96 | 66 | 45 | 31 | 21 | 15 | 10 | 7 | 5 | 10 |
| 75% | (1,331) | (1,515) | 76 | 45 | 26 | 15 | 9 | 5 | 3 | 2 | 1 | 2 |

| Incremental Economics: Case Three and Case One | | | | Internal Rate of Return | | | 10.1% | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Year-------------------------> | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | |
| **Case Three** | | (2,991) | 590 | 608 | 626 | 645 | 664 | 684 | 705 | 726 | 748 | 8,827 |
| **Case One** | | (1,215) | 414 | 427 | 440 | 453 | 466 | 480 | 495 | 510 | 525 | 6,199 |
| Incremental | | (1,776) | 176 | 181 | 186 | 192 | 198 | 204 | 210 | 216 | 223 | 2,628 |
| Discounted Cashflow | | | | | | | | | | | | |
| 10% | 14 | (1,693) | 152 | 143 | 134 | 125 | 117 | 110 | 103 | 96 | 90 | 638 |
| 15% | (459) | (1,656) | 142 | 128 | 114 | 102 | 92 | 82 | 74 | 66 | 59 | 338 |
| 20% | (729) | (1,621) | 134 | 115 | 98 | 85 | 73 | 62 | 53 | 46 | 39 | 187 |
| 25% | (892) | (1,588) | 126 | 104 | 85 | 70 | 58 | 48 | 39 | 32 | 27 | 107 |
| 30% | (993) | (1,557) | 119 | 94 | 74 | 59 | 47 | 37 | 29 | 23 | 18 | 63 |
| 40% | (1,101) | (1,501) | 106 | 78 | 57 | 42 | 31 | 23 | 17 | 12 | 9 | 24 |
| 50% | (1,145) | (1,450) | 96 | 66 | 45 | 31 | 21 | 15 | 10 | 7 | 5 | 10 |
| 75% | (1,158) | (1,342) | 76 | 45 | 26 | 15 | 9 | 5 | 3 | 2 | 1 | 2 |

| Incremental Economics: Case Four and Case One | | | | Internal Rate of Return | | | 14.1% | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Year-------------------------> | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | |
| **Case Four** | | (2,570) | 590 | 608 | 626 | 645 | 664 | 684 | 705 | 726 | 748 | 8,827 |
| **Case One** | | (1,215) | 414 | 427 | 440 | 453 | 466 | 480 | 495 | 510 | 525 | 6,199 |
| Incremental | | (1,355) | 176 | 181 | 186 | 192 | 198 | 204 | 210 | 216 | 223 | 2,628 |
| Discounted Cashflow | | | | | | | | | | | | |
| 10% | 415 | (1,292) | 152 | 143 | 134 | 125 | 117 | 110 | 103 | 96 | 90 | 638 |
| 15% | (66) | (1,264) | 142 | 128 | 114 | 102 | 92 | 82 | 74 | 66 | 59 | 338 |
| 20% | (345) | (1,237) | 134 | 115 | 98 | 85 | 73 | 62 | 53 | 46 | 39 | 187 |
| 25% | (516) | (1,212) | 126 | 104 | 85 | 70 | 58 | 48 | 39 | 32 | 27 | 107 |
| 30% | (625) | (1,188) | 119 | 94 | 74 | 59 | 47 | 37 | 29 | 23 | 18 | 63 |
| 40% | (745) | (1,145) | 106 | 78 | 57 | 42 | 31 | 23 | 17 | 12 | 9 | 24 |
| 50% | (801) | (1,106) | 96 | 66 | 45 | 31 | 21 | 15 | 10 | 7 | 5 | 10 |
| 75% | (840) | (1,024) | 76 | 45 | 26 | 15 | 9 | 5 | 3 | 2 | 1 | 2 |

**Exhibit 7-9: Summary of Incremental Economic Analyses**

Case One was compared to the Base Case in order to examine the economics of adding enough Shengdong generator sets to fully utilize the methane that is available under the current in mine drainage drilling method. The incremental economics indicate that installation of an additional five gen sets would achieve an incremental internal rate of return (IRR) of 29.1%.

Because Case One exhibited a positive incremental IRR, it was used as the reference case against which Cases Two, Three, and Four were compared. The incremental IRR for Case Two compared to Case One was 8.5%. The incremental IRR for Case Three compared to Case One was 10.1%. Finally, the incremental IRR for Case Four compared to Case One was 14.1% and this is the most favorable of the three incremental cases considered. Exhibit 7-9 is a summary of the incremental analyses performed.

The results of the incremental analyses lead to ARI's recommendation that higher efficiency generator sets, with a total capacity of 2.5 MW, are installed at Hebi Mine No.6. The generators will utilize the proposed increased available volumes of CMM and generate electricity for mine use.

## 7.5 Appendices

### 7.5.1 Apendix A – Price Quote for Shendong Generator Set

**DongGuan ShengDong New Energy Technology Co.,Ltd**

Supply you the best price performance ratio Diesel Generator Set and Gas Generator Set (OEM is available)

Total :(1-4 parts)

***Part one --Quotation for our CMM Genset***

A . Quotation For 500 KW CMM Generator set :

| Serial No. | Description | QTY | Unit price | Qty(sets) | Total Amount |
|---|---|---|---|---|---|
| 1 | 500GF1-2RW Coal Mine Methane Generator Set | 1 sets | USD145,000.00 | 1 | USD145,000.00 |
| 2 | 500GF1-3RW Coal Mine Methane Generator Set | 1 sets | USD145,000.00 | 1 | USD145,000.00 |
| 3 | Control Panel with control cable and batteries | 1 sets | Included | 1 | Included |
| 4 | Batteries for starting | 1 set | Included | 1 | included |
| 5 | Silencer and exhaust pipe | 1 sets | Included | 1 | included |
| 6 | Specific documents | 1 sets | Included | 1 | included |

**Part Ⅱ: Instruction for the CMM Generator set :**

CMM generator sets from the successful development has been through a number of technical improvements, especially in recent years we has 20 items technical improvements were made to greatly promote performance and reliability .

1>With lean burn technology and combustion control technology, which can effectively reduce the engine cylinder temperature and exhaust temperature, and increase combustion efficiency, thereby enhancing engine performance and power of the gas-fired units to ensure the full sound of each cylinder combustion, to ensure the smooth functioning of the unit;

2>Can adapt to extremely low pressure gas without pressurization, reduce investment and raise the effective power generation capacity;

3>High efficiency, thermal efficiency can up to 32-40%;

4>Self-contained units,only need few auxiliary equipments ,simple to make plant and install and reduce investment

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Making the Best Price Performance Diesel Generator Set

http://www.sdnetech.com Tel: +86 769 81925051 Fax:+ 86 769 86729611 Email: sdwm@sdnetech.com

5> Making plant period is less than 2 months, high efficiency with low operating cost.

6> Units can be single use, but also combination of multiple use, cogeneration and networks;

7>Start from start the genset to the grid with high speed, can be finished within a short time , to achieve combined to networks or independent power with simple operation, ordinary workers will be able to master through short-term training . Compared to other gas-fired electricity generation method, the adjustment of peaking are the best one .

8>quality is reliable, output power is the same improve 50% than the same power of diesel power with small load.

9> Master key controls some of the parts, such as speed control system, ignition, are imported parts;

10>Unit have complete protection systems; mature, technology there are more than 20 years of production history; adequate spare parts, with service is timely .

## *Part Three : Delivery, Payment and Others*

**NOTE:**

1、All the quotation based on FOB Shengzhen

2、Packing: naked package (accessaries: wooden Export standard)

3、Payment : 30% by T/T for deposit, the rest of 70% by irrevocable L/C at sight, should be reaching us before delivery。

4、Delivery time: 35 days after getting 30% deposit by T/T.

5、Service rules :if custome requires, we will arrange engineer to your country to service it freely. The customers will be charge of the round trip air tickets fee and room and board fee abroad. Also, commissioning and training is free.

6. The price including gas generator set and other accessaries such as control Panel, control cable, batteries, Silencer, exhaust pipe, specificate documents etc.

7. The price is of full new gas generator set. **Not modification gas generator.**

**8. This quotation is valid for 2 months**


http://www.sdnetech.com Tel: +86 769 81925051 Fax:+ 86 769 86729611 Email: sdwm@sdnetech.com

**DongGuan ShengDong New Energy Technology Co.,Ltd**
Supply you the best price performance ratio Diesel Generator Set and Gas Generator Set (OEM is available)

## *Part four : Technique Data*

| Model Type | 500GF1-2RW | 500GF1-3RW |
|---|---|---|
| Methane (CH4) | ⩾25% | 9%-25% |
| Ourput Power KW | 500 | 500 |
| Voltage V | 400 | 400 |
| Engine type | $W12V190Z_LD_K$-2B | $W12V190Z_LD_K$-2C |
| Aspiration | Turbocharged inter-cooled | Turbocharged inter-cooled |
| Arrangement of cylinder | V-12 , 4-stroke-cycle | V-12 , 4-stroke-cycle |
| Bore/Stroke | 190/210 | 190/210 |
| Engine speed (rpm) | 1000 | 1000 |
| Fuel consumption MJ/kwh | 9.8 | 10.50 |
| Exaust temp℃ | ≤550 | ≤550 |
| Ignition mode | Spark-Ignited | Spark-Ignited |
| Starting mode | 24V DCPower | 24V DCPower |
| Total Displacement (Lit) | 71.45 | 71.45 |
| Isulation | Class F | Class F |
| Excitement | Brushless excited | Brushless excited |
| Dimension: LxWxH (mm) | 5434x1970x2822 | 5434x1970x2822 |
| Weight (kg) | 12500 | 12500 |

*All data according to full load subject to technical development and modification.*

CMM should be purified before burning in engine
CMM Temperature ⩽40℃
CMM pressure 3-10k Pa ; Fluctuate rate of pressure ⩽ 1 kPa/Min
$CH_4$ ⩾9% ; Fluctuate rate of $CH_4$ ⩽ 2%/min
Granule ⩽5 μ m, Granule ⩽ 30 mg / Nm³
Moisture ⩽40g / Nm³
For safety purpose ,the $O_2$⩾16% and total volume of $CH_4$+$O_2$⩾28% if $CH_4$⩽30%

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# SECTION 8

# Potential Impacts and Recommendations

# SECTION 8 CONTENTS

## 8.1 Summary

The proposed coal mine methane drainage and utilization improvement project at Hebi Mine No.6 has considerable positive technical, economic, and environmental merit. The proposed new methane drainage techniques would improve the safety and technical efficiency of CMM drainage and transport at the mine, particularly as deeper coal seams with greater methane content are mined. The resultant production of CMM with higher methane concentration would expand the range of CMM safe utilization options. By using CMM supplies that are currently being vented, the project would monetize an otherwise wasted energy source and reduce total GHG emissions associated with the mine.

The estimated financial performance of the Hebi project is robust, while the risks of increased capital and operating costs, reduced power prices, and other variables appear to be moderate and manageable. If successful, the advanced techniques, equipment, and management practices demonstrated by the project could be applied broadly to the other coal mines in the Hebi Coal Field, resulting in significantly increased CMM utilization and reduced GHG emissions in this strategic coal mining region.

## 8.2 Potential Impacts of the Project

**Environmental Impacts.** In 2007 Hebi Coal Industry Group (HCIG), prepared an environmental impact study of a conceptual 3 x 500 kW power generation project at Hebi Mine No.6. This study evaluated potential surface, air, water, noise, traffic, and other impacts and concluded that no significant environmental impacts would be caused by the project.

Likewise, the currently proposed power generation project, with an expansion from 5 x 500 kW generators to 10 x 500 kW generators, is expected to have negligible overall environmental impacts, with the exception of small but manageable local increases in $CO_2$, CO and NOx emissions from the internal combustion (IC) engines. Impacts from increased coal production, traffic, and infrastructure construction related to the project are also considered to be negligible.

**Avoided Emissions.** The project envisions capturing and using all of the CMM currently vented to the atmosphere, along with the increased drained volumes from the mine, with avoided emissions calculated to be approximately 237,800 tonnes $CO_2$eq per year - the equivalent of removing 41,260 cars from the road.

**Air Quality.** The project is expected to have positive overall impacts on local and regional air quality. Power generation utilizing CMM fuel is far cleaner than that fueled by coal, which is the dominant fuel source for power generation and boilers in the Hebi area and Henan Province. The use of CMM-fueled power generation by the mine would back out coal-fired power purchased from the grid, resulting in lower overall emissions at the province level.

The combustion of CMM in gas engines produces $N_2$, $CO_2$, CO and some NOx. China regulates NOx as a pollutant, and its production depends largely on the gas combustion temperature. As gas combustion will take place at temperatures below 1,000 C, NOx production is expected to be limited to about 50 $mg/Nm^3$. This is safely below the regulatory limit for coal-fired plants which, according to GB13223-2003 (Chinese Emission Standard of Air Pollutants for Thermal Power), is set at 80 $mg/Nm^3$.

**Increased Coal Production.** By enhancing the efficiency of CMM drainage, the project could facilitate and reduce the costs of coal production at Hebi Mine No.6. More effective pre-drainage of methane from the coal seam has the potential to allow increased mining rates, while keeping methane concentrations in the mine workings at safe operating levels.

**Water Use.** The main potential source of water consumption for the project is cooling water required by the additional reciprocating engine power generators. However, the vast majority of water required by the project could be supplied from suitably treated wastewater drained from the mine. Dispensed cooling water can be used for irrigation purposes in order to reduce dust. No new pollutants are added to the wastewater by the project.

**Increased Traffic.** The project is not expected to result in any major increase in traffic above or inside the mine and may decrease traffic volume. The CMM drilling and pipeline equipment could be delivered in several large truck loads. Maintenance would take place primarily within the existing mine drilling repair shop. It is possible the improved borehole drilling will reduce the level of traffic at the mine, since there will be fewer, but longer, boreholes drilled and thus reduced equipment mobilization. Also, mined gob drainage galleries will be replaced with directionally drilled gob boreholes, reducing the removal of material from the mine.

Regarding the power generation component of the project, there would be a slight increase in traffic during the construction period, requiring several dozen heavy truck loads to deliver the IC engines and related equipment. However, current traffic at Hebi Mine No.6 is moderate and can be handled by the existing road system both inside and surrounding the mine. Following construction of the power station, traffic levels would likely return to current levels. Overall, the project is expected to have negligible and easily manageable impacts on the traffic at Hebi Mine No.6. No additional road construction or modification in traffic patterns would be needed to accommodate the project.

**Infrastructure Impacts.** The CMM drilling component would be implemented within the existing mine design, with no significant modifications required to the mine infrastructure. The existing mine hoists, roads, power facilities, water supply, and cuttings disposal systems appear to be adequate to handle the proposed drilling and drainage improvements.

The proposed power station requires expansion of the existing facility housing the IC engines and related equipment, doubling its size. This should be able to be accommodated within the existing footprint of the mine boundaries.

**Noise.** Increased noise will be produced from the additional reciprocating engines, generators, exhaust releasers and water pumps. Without any noise protection measures, noise levels are expected to range from 67-95 dB on the project site. With noise protection measures (such as mufflers on exhaust pipes and workshop sound insulation) noise levels can be reduced to about 61-75 dB on site. The environmental impact assessment considers noise to be the most important environmental impact of the project. Hebi Mines No. 6 has housing for miners in the nearby vicinity and specific noise reduction measures must be implemented in order to comply with regional noise regulations.

**Increased Employment.** As a capital-intensive activity, the proposed CMM drainage and utilization project is not expected to create a significant number of new jobs at Hebi Mine No.6. The current drilling and drainage personnel could be trained to operate the new drilling and pipeline construction equipment, with no overall increase in employment expected. However, the proposed expansion of the power generation plant would require several new maintenance and engineering positions, some requiring advanced training in IC engine maintenance and power engineering. Complex tasks such as IC engine overhaul would be contracted to outside specialists, most likely the engine manufacturer; these costs have been accounted for under routine power operating expenses.

**Scientific and Technical Impacts.** Successful implementation of the proposed advanced technologies at Hebi Mine No.6 could provide a demonstration that would facilitate adoption of improved CMM drainage and use techniques at the other mines in the Hebi region. This could help dramatically reduce CMM emissions in the Hebi Coal Field.

## 8.3 Recommended Next Steps

With the evaluation and preliminary design phases completed, further steps to progress this proposed project could include:

- Internal HCIG technical and economic project evaluation; make necessary modifications to final project design; obtain corporate go/no-go decision.
- Obtain necessary approvals from project technical, financial, social, and environmental regulating authorities.
- Contact equipment and service providers to obtain site-specific quotes for the drilling, pipeline, and power generation equipment, along with delivery timetables and installation and operation costs.
- Conduct project scoping and training visits to other mine locations in China, U.S., and Australia where similar equipment is in operation.
- Register project with CDM approval authorities.