RESEARCH ARTICLE

ANALYSIS OF METHANE GAS CONTENT FROM DESORBED GAS VOLUME DURING COALBED METHANE

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ABSTRACT

During the present days of energy crises and increasing gap in the demand and supply of energy all over the world, it is utmost important to make an optimum usage of all the energy resources to its best exploitation and also to search for the alternate energy source for meeting the present and future energy requirements for sustainable development and economic growth. The search for the alternate energy brought the advent of Coal Bed Methane development. Coal Bed Methane is a greenhouse gas which is considered to be 21 times more harmful than carbon dioxide. Methane is absorbed in coal seams and the surrounding strata and released during coal mining. Small amounts of methane are also released during the processing, transportation and storage of coal. Methane can cause explosions in underground mines when it is trapped in coal beds and then suddenly released during mining. Recovery of CBM, which escapes into the atmosphere can not only reduce the mining hazard but also can be used as a source of energy and fuel as it is a remarkably clean fuel. In this study, south-western part of Raniganj Coalfield has been selected and gas content is determined by analyzing the collected sample. This approach was performed as a contribution to the development and to evaluate the economical feasibility of the reservoir. Our aim is to reduce emissions which come from mines and reduce mining hazard. Methane emission from open cast mining is around 8% which may increase up to 20% since 2000-2020.

Key words: Recovery of CBM, Greenhouse gas, Exploitation, Atmosphere, Surrounding strata, Economical feasibility.

INTRODUCTION

Coal is a complex mixture of plant substances altered in varying degree by physical and chemical processes. These processes which changed plant substances into coal has taken million of years and has been accomplished by bacteria, heat and pressure inside the earth's crust. Coal is a valuable and plentiful natural global resource. Coal is a heterogeneous rock, usually black but sometimes brown, carbon-rich material that occurs in stratified sedimentary deposits. Energy availability and its utilization is most important factor for development of a country. India is trying hard to meet increased energy demand from population growth and economic expansion. In power sector, coal alone accounts for 70% contribution while hydro (20%), oil and gas (8%) and nuclear (2%) lags far behind. We are experiencing a power shortage of almost 11.5%. This has resulted enormous pressure on Government of India to adopt new strategies for the resource characterization of varied energy inputs, and provide the best possible infrastructure for adopting new technology to the industry involved in exploration and exploitation of conventional and non-conventional fossil fuels. Coal bed methane, an unconventional source of natural gas from the coal beds is now considered as an alternative source for supplementing the country's energy resources. Coal Bed Methane (CBM), a hydrocarbon (CH4) in gaseous form has its origin in the coalification process occurring over a period of millions of year out of accumulated plant material.

Most of the CBM gas is in adsorbed state on the micro pores of the coal surface, thus coal is both the source and reservoir rock for CBM. A saturated CBM reservoir could contain up to five times the amount of gas contained in a conventional gas reservoir of comparative size, temperature and pressure. The amount of methane present in coal seams increases with rank of coal and depth of coal seams. A correlation study, carried out at different Research Institutes, shows an increase of 1.30 m3/t in gas content per 100 m increase of depth

Distribution of coal in India

India's coal is characterized by high ash contents, but it has low sulphur content (generally 0.5%), low iron content in ash, low chlorine content and low trace element concentration. The estimated coal reserves, down to a depth of 1,200 meter, is about 285862.21 Million tones in nearly 60 mines as on 1st April 2011 (Geological survey of India). Of these estimated reserves. About 90% of reserves are economically viable to extract out of which 83% is non coking coal and 14% is coking coal. The majority of the coal reserves are in the states of Jharkhand, Chhattisgarh, Orissa, Assam, West Bengal, Maharashtra, and Andhra Pradesh. There are also lignite deposits in Jammu & Kashmir, Rajasthan, Gujarat, and Tamil Nadu. The coal deposits in southern India are in sedimentary rocks of older Gondwana formations. Those in the north and north-eastern mountainous regions of the country are younger Tertiary formations. In Figure, the distribution of coalfields in India has been shown

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Distribution of coals in India can be divided into:

a) Lower Gondowana Coalfields,
b) Upper Gondowana Coalfields,
c) Tertiary Coalfields.

Gondawana Coal Reserves

State wise geological resources of coal (in Million Tonnes)

State	Geological Resources of Coal			
	Proved	Indicated	Inferred	Total
Andhra Pradesh	9296.85	9728.37	3029.36	22054.58
Assam	0	2.79	0	2.79
Bihar	0	0	160	160
Chhattisgarh	12878.99	32390.38	4010.88	49280.25
Jharkhand	39760.73	32591.56	6583.69	78935.98
Madhya Pradesh	8871.31	12191.72	2062.70	23125.73
Maharashtra	5489.61	3094.29	1949.51	10533.41
Orissa	24491.71	33986.96	10680.21	69158.88
Sikkim	0	58.25	42.98	101.23
Uttar Pradesh	866.05	195.75	0	1061.80
West Bengal	11752.54	13131.69	5070.69	29954.92
Total	**113407.79**	**137371.76**	**33590.02**	**284369.57**

Tertiary Coal Reserves

State	Geological Resources of Coal				
	Proved	Indicated	Inferred (Exploration)	Inferred (Mapping)	Total
Arunachal Pradesh	31.23	40.11	12.89	6.00	90.23
Assam	464.78	42.72	0.50	2.52	510.52
Meghalaya	89.04	16.51	27.58	443.35	576.48
Nagaland	8.76	0	8.60	298.05	315.41
Total	**593.81**	**99.34**	**49.57**	**749.92**	**1492.64**

(Source: Geological Survey of India)

COALBED METHANE

The primary energy source of natural gas is a substance called methane (CH_4). Coal bed methane (CBM) is simply methane found in coal seams. It is produced by non-traditional means, and therefore, while it is sold and used the same as traditional natural gas, its production is very different. CBM is generated either from a biological process as a result of microbial action or from a thermal process as a result of increasing heat with depth of the coal. Often a coal seam is saturated with water, with methane is held in the coal by water pressure. In recent times it has become a major source of energy in several countries. It is also called as 'sweet gas' because of lack of hydrogen sulphide in it. The main difference of the natural gas obtained from the conventional reservoir to that from CBM is that it contains only little amount of heavier hydrocarbons like propane or butane.

Formation of Coal Bed Methane

Methane is generated during the formation of coal through coalification process of vegetable matter. This process can be broadly divided into two stages namely:

Biochemical & Physico-chemical, involving the following steps in succession:

- Peatification (anaerobic degradation of organic matter in peat swamp).
- Humification (formation of dark coloured humic substances).
- Bituminisation (thermal degradation of organic matter and the generated hydrocarbons).
- Debituminisation (thermal degradation of organic matter and the generated hydrocarbon).
- Graphitization (formation of graphite).

Many physical and chemical changes, governed by the biological and geological factors, occur during the above processes. Whereas darkening in colour and increasing in hardness and compactness are the main physical changes, loss in moisture and volatile contents along with increase in carbon contents are the main chemical changes. Many acids (humic, fatty, tannic, Gallic etc) and, dry and wet gases ($CH4$, $CO2$, $N2$, $N2O$, $H2S$, Ethane Propane, Butane etc) are formed during decomposition of organic matter. Biological stages of coalification begin with the accumulation of vegetables (organic) matter ans its partial degradation by micro organisms (fungi, aerobic bacteria, insects etc.) leading to wide range of products (organo-petrographic entities termed as macerals) in water saturated wet lands (basin/graven). Further decomposition by anaerobic bacteria results in release of methane/marsh gas. During subsequent geochemical stage of coalification, rising temperature and pressure due to subsidence of basin/graven, either by growing thickness of overburden or by tectonic activities, generate hydrocarbon (hydrogen rich constituents). Thermal cracking of free lipid hydrocarbons and/ or cracking of kerogen fraction of coal generate methane gas. Thus, the generation of CBM during coal formation occurs in two principal ways:

- By metabolic activities of biological agencies (biological process)
- By thermal cracking of hydrogen rich substances (thermogenic process).

Methane generated at shallow depths.(<10 m) and low temperature (<500C) by the first process in low rank of coalification is termed as biogenic or digenetic methane. Methane generated in the second step (catagenesis and metagenesis) is called as called as thermogenic methane. Biogenic methane constitutes only about 10% of the total methane whereas thermogenic methane constitutes the rest of bulk CBM generate in subsequent step of coalification. In marine environment both biogenic and thermogenic methane are produced with a distinct difference to that of terrestrial environment. Digenesis begins in recently deposited sediments under ambient pressure (water depth of < 1000 m) and temperature (25-500C), and under anaerobic condition leading to biogenic methane. Subsequent increase of hydrostatic pressure and temperature (>1500C) leads to formation of methane by $H2$, $CO2$ (carbonate reduction) and decarboxylation of acetate in the complete absence of sulphate. Methane generated remains as solution in interstitial pore water because of its high solubility at higher hydrostatic pressure (depths) caused by the overlying water column. However, it excludes as free gas from interstitial pore waters on super saturation or by release of hydrostatic pressure.

Transport mechanism of methane in coal

According to literature, the movement of gas in coal has three distinct stages. The first stage involves desorption of the gas from coal surfaces due to decrease in the pressure on the coal

seam that is followed by the second stage of diffusion through the coal matrix from a zone of higher concentration to the cleat system , the zone of lower concentration. Finally in the third stage, the gas flows through the coal seam cleat network under Darcy flow conditions. Although diffusion through the micro pores and Darcy's flow through the interconnected fracture system in the coal beds are separate and distinct phenomenon, they are independent. If one of the steps is considerably slower step, the overall gas flow rate is determined by the magnitude of the slower step. However, no clear answer is available as to which type of behaviour is taking place or which type of transport governs the rate of gas production. One concept is that diffusive flow from the solids between cleats and Darcy flow along the cleats structure takes place. This view, however, is not universal.

Regardless of the flow mechanism which dominates, the micro pore transport of gas obeys
Fick's law of diffusion:

$$Q/A = D \times \partial C/\partial L$$

Observation of some coals in the world indicates that the most important model of fluid transport is Darcy flow in the cleats. The reasons for this are the close spacing of the cleats (typically 20 to 150 mm), the fact that most flow is measured as occurring along the cleats, the generally low bulk permeability of the coal, and the ready desorption of core in gascontent tests. The last involves taking coal core from borehole, placing it in container, and measuring the evolved. According to Darcy's law the flow of gas can be expressed as:

$$V = q/A = K\,\partial PS/\mu\partial L$$

Where;

K = Permeability, the property of the rock that allows fluid to flow through it, Darcy
q = Rate of flow
A = Area of cross section of the coal core, cm2
μ = Viscosity of gas, cp
PS = Inlet pressure of the core, atm
L = Length of core, cm

The gas transport equation must equation must account for the gas slippage phenomenon. The correction for gas slippage usually takes the form of Klinkenberg equation.

$$Ke = K\infty(\,1 + b/P\,)$$

In other approach, the slip velocity is superimposed on to the Darcy velocity and is substituted directly into the transport equation after Fick's law. The advantage of this procedure is that the gas, which is slipping, can be treated as real gas (Klinkbera equation was derived assuming ideal gas behavior). Starting from a differential mass balance on the gas in macropore, horizontal and isothermal flow can be written in the form:

$$\Delta a.(\rho gV) + qai = \partial\,(\varphi a\rho gSag)/\partial t$$

Where V is the total gas velocity. This velocity is equal to the Darcy velocity plus the slip velocity.

Type of Coal Bed Methane

Different types of coal bed methane are as given:

Coal Mine Methane (CMM)

Methane is released as a result of mining activity when a coal seam is mined out and if not controlled to prevent the accumulation of flammable mixtures of methane in air (5-15%) it presents a serious hazard. Gas drainage techniques are used to enable planned coal production rates to be achieved safely by reducing gas emissions into long wall mining districts to a flow that can be satisfactory diluted by the available fresh air. In some instances gas drainage is also needed to reduce the risk of sudden, uncontrolled emissions of gas into working districts. In well managed mines, in favorable geological and mining conditions, the methane concentrations in drained CMM can reach 70% or more. CMM of such quality may be utilized. However, poorly drained mines will only achieve methane concentrations that are much lower, and may be too low for conventional utilization purposes. Methane capture and its utilization from coal mines is generally not practiced in India as current levels of coal production in gassy mines are generally achievable using ventilation controls but even where there may be some safety benefit there is some resistance to introducing gas drainage due to lack of technology, expertise and experience. Additionally, there is the perception that CMM utilization is not commercially viable.

Ventilation Air Methane (VAM)

Methane released from coal seams into the ventilation air of the active coal mine is called Ventilation Air Methane (VAM). Concentrations of methane in the ventilation air are generally, limited by law, for safety reasons, at 0.5 to 2% in different parts of a mine with variations depending on the country. Concentrations can be controlled by the volume of ventilation air circulated (dilution) or through special drainage (CMM). The concentration of methane in VAM is typically 0.8% or less and is too low for conventional utilization purposes. However, technologies are being developed to remove the methane, and where additional gas is available to generate electricity using the thermal energy recovered.

Abandoned Mine Methane (AMM)

When an active coal mine is closed and abandoned, methane continues to be emitted from all the coal seams disturbed by mining, decaying gradually over time unless arrested by flooding due to groundwater recovery. Depending on the methane concentrations, local regulations and the geology it may be possible, or required for public safety reasons to continue draining or venting this Abandoned Mine Methane. AMM extraction and utilization schemes aim to recover the gas left behind in unmined coal above and below goof (worked out) areas formed by long wall mining methods. The gas can either be transported by pipeline to a nearby user consumer for combustion in boilers or used on site to generate electricity for local use or sale to the grid. AMM reservoirs consist of groups of coal seams that have been de-stressed, and therefore of enhanced permeability, but only partially degassed by long wall working. Favorable project sites are those where a market for the gas exists, the AMM reservoir is of substantial size and not affected by flooding and the gas can be extracted at reasonably high purity. A number of schemes are in place in

countries such as U.K. and Germany . No AMM schemes are in place in India and initial investigations show limited promise.

Virgin Coal bed Methane (VCBM)

Coal bed methane and virgin coal bed methane are terms conventionally used for methane drained and captured directly from coal seams.CBM is generally reserved to describe the gas produced from the surface bore holes ahead of mining for coal mine safety and coal production reasons. VCBM is produced by similar process but completely independent of mining activity. Methane concentration in VCBM is generally very high (around 90%) and can be used as a replacement for natural gas supplies.

Typical composition of the gases emitted during mining:

Methane	97.00%
Ethane	0.53%
Carbon dioxide	0.84%
Nitrogen	1.600%
Hydrogen	0.019%
Helium	0.047%

METHODOLOGY

IN-SITU GAS CONTENT DETERMINATION

In this method the gas content of coal is determined by collecting and measuring the volume of gas released from a sample of coal core taken out from the coal-seam by drilling. Immediately after drilling, the recovered coal-core sample is placed in a specially designed canister provided with sealing arrangement and is sealed. The atmospheric pressure (at the surface) being lower than the underground reservoir pressure, the coal-core sample starts releasing gas through desorption inside the closed canister. This can be seen from the increase in pressure in the pressure gauge provided at the top of the canister. At required intervals, the gas is taken out from the canister through outlets and its volume is measured by gas measuring devices. This process is allowed to continue till the release of gas comes to an end. The gas content of coal sample is determined from the measured volume of total gas released from the sample and the weight of the coal-core sample. After drilling, the actual release (desorption) of the total volume of gas is estimated in stages, which comprises the following components:

- Sampling of coal core
- Measurement of Desorbed Gas (Q1)
- Determination of Residual Gas (Q2)
- Estimation of Lost Gas (Q3)
- Total Gas Volume (Q4)

Sampling of coal cores

The person collecting the coal samples in the field must be present at the site when the coal bed is cored. To calculate a portion of the total gas content, that person must accurately record the exact times of coal bed encountered, start of coal retrieval and lapsed time until the sample is sealed in the sample disaster.

Measurement of Desorbed Gas (Q1)

The volume of desorbed gas released from the coal-core sample kept in a desorption canister (which is shown in figure 8) is measured about every five minutes (depending on number of active canisters) and the data for short-term desorption period is collected; which are used for estimating the "Lost Gas Volume" desorbed from the same sample during its retrieval and handling at the surface. After the first hour of gas volume measurement, the frequency of measurement is decreased depending on gas desorption rate from the canisters. Such measurement are continued till the volume of gas released falls below the resolution at which it can be measured accurately (say 0.1 to 1 cc). The volumes of the gases are measured by the water displacement method in a inverted graduated cylinder illustrated in Figure.

During measurement the following data are to be noted carefully

- Head Space Volume (CC)
- Canister Temperature (C°)
- Ambient pressure (Psig/Kg/Cm^2)
- Periods of excessive pressure (>10 psig) in the desorption canister(s)
- Desorbed Gas Sample collection intervals (Minute)
- Desorbed Gas composition as a function of time
- Length of desorption test (Minute)
- Sorption Time (Minute)
- Coal-core sample weight. (g)

After collection of first few desorption data (every five minutes interval) during the first hours, the frequency of data collection is reduced to once or twice every hours for the first 24 hours and then to once or twice every day till the rate of released gas volume comes to 0.05 ml/g/day for several consecutive days. Thereafter, when the coal sample ceases to release any more gas effectively, the sample is then sent for determination of Residual gas. The changes in ambient temperature and pressure are recorded at the time of taking each reading for the correction of gas volumes to Standard Temperature and Pressure (STP). The cumulative value obtained from measurement of desorbed gas volumes give the "Desorbed Gas" (Q1) Value for the coal-core sample.

Determination of Residual Gas (Q2)

Method

After determination of Q1, the core-coal sample is weighed and a known weight of this sample is transferred into an air-tight steel vessel of specific dimension. The vessel contains several brass rods inside it which grind the core sample placed inside the vessel on rotating the vessel by the help of a set of rubber rollers driven by a motor. The vessel is rotated at a particular RPM rate for a specific period of 40 Minutes. [The present coal crushing Mill used for pulverization of coal sample is similar in design as was used by Diamond and Levine (1970) and it is found that it crushes the coal sample down to a fine powder of below 200 mesh size in about 40 Minutes rotation of the vessel.] The vessel is also equipped with separate gas inlet and outlets and prior to start grinding, the vessel is purged with an inert gas (N2 or Argon) to avoid

adsorption of atmospheric oxygen (initially present inside the vessel) by the crushed coal. The volume of residual gas released after crushing the coal is measured by water displacement method in a calibrated burette. From the measured gas volume obtained from a portion of the coal-core the total Residual gas (Q2) is calculated for the total weight of the original core-coal sample used in the desorption test earlier.

Estimation of Lost Gas (Q3)

The moment the coal-core sample is recovered from the well bore, desorption of gas from the sample gets started and continues till the actual process of gas content measurement can be started inside the canister. The volume of this unrecoverable portion of gas is termed as "LOST GAS" (Q3)

Method

The Lost gas is calculated by a graphical method which is based on the volume of gas emission during first few hours data (obtained from desorption test) and square root of desorption time data. The drilling medium used has a great influence on the amount of Lost gas and the following data are required to estimate it from the equations (I) and (II) given below and to construct the Lost gas graph.

Experimental data required

- Drilling Medium (Air/Mist/Water/Mud)
- Time coal-bed encountered (A)
- Time core started out of borehole (B)
- Time core reached surface (C)
- Time core sealed in canister (D)
- Lost gas time calculation is done as below by using equations;
  o   Lost gas time: (D-A) if air or mist is used
  o   Lost Gas Time = (D-C)+ (C – B)/2

Determination of Total Gas Volume (Q)

The total gas volume obtained by addition of Q1, Q2 and Q3 gives the in situ gas content of the coal – core sample.

$$\text{Total Gas Content of coal (cc/g)} = \frac{Q1 + Q2 + Q3}{W}$$

Where W is the weight of coal-core sample taken in canister.

Sorption Time (τ)

The desorption time constant (sorption time), usually designated by the Greek letter "tau" (τ), provides an indication of the rate that gas diffuses out of the coal. The parameter originates from the basic equation used in reservoir simulators to account for gas diffusion via a first order kinetic model also known as a pseudo-steady-state model (Hoysan, 1981 and 1982) given as follows :

Where C = Adsorbed gas concentration, t = time, τ = desorption time constant and $C_e(p)$ = Equilibrium gas concentration at pressure (p) .

When combined with the mathematical boundary conditions imposed by a step change in pressure on a coal core (as when

core is quickly brought to the surface), it is found that tau (τ) is equal to the time required for

$$\tau = (1\text{-} 1/e) * 100 = 63.21 \text{ \%}$$

Of the total gas content of a core to be desorbed (Sawyer, 1987).

Analysis of Coal

There are two methods: ultimate analysis and proximate analysis. The ultimate analysis determines all coal component elements, solid or gaseous and the proximate analysis determines only the fixed carbon, volatile matter, moisture and ash percentages. The ultimate analysis is determined in a properly equipped laboratory by a skilled chemist, while proximate analysis can be determined with a simple apparatus. Here in this study values from proximate analysis has been used.

Proximate analysis

For general purpose proximate analysis is taken into consideration. It includes determination of moisture, volatile matter, fixed carbon and ash content. The procedures for proximate analysis are rather empirical, but do not require elaborate costly equipments. As such this analysis is widely used for industrial purpose and also for grading the coals.

Moisture content

Water is considered to occur in four different states in coal, as described by Krumin (1963).

Adherent moisture

It is mechanically retained on the surface of the coal or in cracks and internal cavities are so large to be considered part of the structure of the coal substance, and possessing normal vapour pressure. The synonymous terms of adherent moisture are "free moisture", "bulk water", "superficial water".

Inherent moisture

These are condensed or physically sorbed in the capillaries and microspores of the coal substance, distinguished by subnormal vapour pressure. Synonymous terms are "true bed moisture", "natural bed moisture", or "capacity moisture".

Chemically combined water

It is bound into molecular structure of the coal and released only by the breaking of molecular bonds. This can occur either naturally during coalification or artificially during pyrolysis.

Moisture of Hydration

It is the moisture of hydration of inorganic constituents in the coal, especially clay minerals. The moisture content of any given coal sample is variable, and may range from near zero up to a maximum capacity moisture content, which is reflective of the rank of the coal and composition.

Measurement of moisture

For the determination of inherent moisture 1 gm of air dried coal is taken in a silica dish and heated to a temperature of 100 – 110 degree centigrade for one hour. The loss in weight

before and after the heating is taken as moisture. The loss in weight is reported as percentage of the original weigh as moisture content.

Calculation

Before heating
Weight of dish = a gm
Weight of dish + coal = b gm
Weight of coal = (b-a) gm

After heating
Weight of dish + coal = c gm;
Weight of coal without moisture = (c-a) gm;
Moisture % = (c-a) / (b-a) x100

Volatile matter

For measuring volatile matter 1 gm air dried coal is heated under controlled conditions in a standard crucible with a lid. The crucible is placed in a furnace and heated to approximately 950 degree centigrade for a period of 7 minutes. The loss in weight after heating is calculated as percentage of the sample taken for the test. This gives the percentage of moisture and volatile matter. To obtain the percentage of volatile matter, the moisture content should also be determined at the same time. The moisture content value is deducted from the total percentage of volatile matter obtained in volatile matter determination.

Calculation

Before heating
Weight of dish = a gm
Weight of dish + moisture free coal = b gm
Weight of moisture coal = (b-a) gm

After heating,
Weight of dish + moisture free coal = c gm; Weight of coal without VM = (c-a) gm;
Volatile matter % = (c-a) / (b-a) x100

Ash

Ash is obtained by the complete combustion of the inorganic mineral matter of coal. The mineral matter in a coal seam may be of two types. One type is inherent mineral matter which is intimately associated with the coal. This type of mineral matter comes in contact of coal during the early stage of coal formation partly as terrigenous matter and partly it is derived from the peat forming plants. The other is the adventitious or epigenetic mineral matter. This is deposited subsequent to the formation of coal in its cracks, fissures, cleavages or cleats through percolating water. The mineral matter in coal after combustion is converted into ash. For determination of ash 1 gm of air dried coal is heated up to 800 +/- 20 degree centigrade for 1 hour in furnace. The dish is then taken out and cooled in a desiccators and weighed. The remaining weight is ash content.

Fixed Carbon

Fixed carbon (FC) is the weight loss upon combustion of a devolatalized coal sample Fixed carbon is not determined. It is estimated by deducting the sum total of moisture%, volatile matter% and ash% from 100.

In other words,

Fixed carbon = 100 – (M + V.M. + A)
Where, M = moisture%
V.M. = volatile matter%, A = ash content%

Indirect methods for estimating Gas Content

Gas contents can be estimated indirectly based on sorption isotherm data (Kim, 1977) or empirical estimation curves of measured gas content results plotted against other measurable variables such as coal bed depth and coal rank (Diamond *et al.*, 1976; Mc Fall *et al.*, 1986). Laboratory derived sorption isotherms describe the quantitative relationship between adsorbed methane at varying pressures and a constant temperature, and provide a measure of the maximum methane sorption or storage capacity of the coal sample. Thus, gas content estimates based on sorption isotherm data do not necessarily result in accurate in situ gas content values. Since all coal beds are not fully saturated with methane, especially those at shallow depths, the isotherm-based methods may over estimate the actual gas content.

Efforts to estimate the gas content of coal beds utilizing wire line geophysical logging tools have also been attempted (Mullen, 1989). The wire line logging method does not directly measure the gas content of the coal beds exposed in the wellbore. It is essentially an empirical estimation curve technique. Algorithms relating gas content to apparent coal rank are derived from actual gas content and coal proximate analysis data from cores obtained in the geographical area of interest. Log-derived coal property data are then used to estimate gas content as a function of coal rank and depth. Indirect methods can serve as a preliminary assessment tool for mine planning purposes or targeting potential areas for commercial coal bed methane exploration. Whenever possible, however, engineering and/or economic decisions should include data from actual direct measurement tests. Indirect empirical formula based on the proximate analysis and the adsorption studies of coal has been proposed by Kim. A.G, which is

$V = 0.75[(1 - \text{moisture} - \text{ash})/100] \times [k_0 (0.096d)^{n}_o - b(1.8d/100 + 11)$
$k_0 = 0.8 \times FC/VM + 5.6$
$n_0 = 0.315 - 0.01 \times FC/VM$
V – Volume of methane gas adsorbed (cc/g)
k_0 - a constant, in cubic centimetres per gram per atmosphere
n_o - a constant
b- a constant, in cubic centimetres per gram per degree Centigrade
V_w - Volume of gas adsorbed on wet coal (cc/g)
V_d - Volume of gas adsorbed on dry coal (cc/g)

The Methane content depends primarily upon rank and pressure, from the adsorption equation $V = kpn$, where k and n are constants related to rank. By incorporating corrections for moisture, ash, and temperature, and estimating pressure and temperature as a function of depth, the methane content of coal in place can be estimated from the following equation: Values calculated with this equation generally are in reasonable agreement with direct determinations. By assuming a standard moisture and ash content, and using the hydrostatic head to estimate pressure, a graph of rank and depth versus gas content was constructed. Although estimated values were consistently high for several high volatile bituminous coals from an area

where the pressure is known to be less than hydrostatic, the estimated methane content for most coals shows reasonable agreement with values determined by the direct method.

Utilization of Coal-Bed Methane from mines

Power Generation

CBM can be ideal fuel for co-generation power plants to bring in higher efficiency and is preferred fuel for new thermal power plant on count of lower capital investment and higher operational efficiency.

Auto Fuel in form of Compressed Natural Gas(CNG)

CNG is already an established clean and environment friendly fuel. Depending upon the availability of CBM, this could be a good end use. Utilization of recovered CBM as fuel in form of CNG for mine dump truck is a good option.

Feed stock for fertilizer

Many of the fertilizer plants in the vicinity of coal mines where coal bed methane is drained have started utilizing fuel oil as feedstock for its cracker complex.

Use of CBM at steel plant

Blast furnace operations use metallurgical coke to produce most of energy required to melt the iron ore to iron. Since coke is becoming increasingly expensive, in the countries where CBM is available, the steel industry is seeking low capital options that reduce coke consumption , increase productivity and reduce operating costs.

Fuel for industrial use

It may provide an economical fuel for a number of industries like cement plant, refractory, steel rolling mills etc.

CBM use in methanol production

Methanol is a key component of many products. Methanol and gasoline blends are common in many countries for use in road vehicles. Formaldehyde resin and acetic acid are the major raw material in the chemical industry, manufactured from methanol.

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