CHAPTER 5

COAL AS A RESERVOIR FOR CBM & FEASIBILITY OF SEISMIC STUDIES

Since the beginning of the coal-bed methane industry, operators have relied greatly on technology from the mining and petroleum industries to evaluate and develop coal-bed methane properties. Much of this conventional oil and gas technology applies to coal-bed methane operations, but often it needs to be modified. In some cases, coal-bed methane operations require entirely different techniques. The unique characteristics of coal reservoirs often are responsible for the need to use a different engineering approach. Through this chapter we focus to learn much about the unique characteristics of coal reservoirs. Also the feasibility studies of Seismic method has been briefly discussed in this chapter.

5. 1 INTRODUCTION

Gas production from coal-beds has become an important energy resource in United States and other countries. Rational development of this resources requires accurate data on geologic and hydraulic properties of the potential reservoirs. Regarding that, characteristics of CBM reservoir is utmost important for the proper exploitation program.

The most important of these characteristics are:

- **Coal is a source rock and a reservoir rock.** The depositional environment and burial history of the coal affect the composition of the gas as well as the gas content, diffusivity, permeability, and gas storage capacity of the coal.
- **The gas storage mechanism of coal.** Most of the gas in coal reservoirs is adsorbed onto the internal structure of the coal, whereas most of the gas in conventional reservoirs is in a free state within the pore structure of the rock. Because large amounts of gas can be stored at low pressures in coal reservoirs, the reservoir pressure must be drawn down to a very low level to achieve high gas recovery .
- **The fracture system of coal reservoirs.** Coals contain small (typically, several per' inch), regularly spaced, naturally occurring fractures called face cleats and butt cleats. Coal reservoirs also contain larger-scale natural fractures.
- **Coal reservoirs often require pumping water before gas is produced.** Typically, water must be produced continuously from coal seams to reduce reservoir pressure and release the gas. The cost to treat and dispose of

produced water can be a critical factor in the economics of a CBM project.

- **The unique mechanical properties of coal.** Coal is relatively compressible compared to the rock in many conventional reservoirs. Thus, the permeability of coal is more stress-dependent than most reservoir rocks. The friable, cleated nature of coal affects the success of hydraulic fracturing treatments, and in certain locations allows for cavitation techniques to dramatically increase production.

5. 2 FUNDAMENTAL THEORY OF CBM PRODUCTION

To successfully produce coal bed methane wells, it is essential to: 1) identify factors that control production in coal reservoirs, 2) understand the relationship between gas content and sorption isotherm for specific developments, and 3) maintain low backpressure on wells to increase recovery.

5. 2.1 FACTORS THAT CONTROL CBM PRODUCTION

Early work showed that gas is stored in an adsorbed state on coal, and thus for a given reservoir pressure much more gas can be stored in a coal seam than in a comparable sandstone reservoir. Production of gas is controlled by a three step process de-sorption of gas from the coal matrix, diffusion to the cleat system, and flow through fractures. Many coal reservoir pressure that holds gas in the adsorbed state.

5. 2.2 RELATIONSHIP BETWEEN GAS PROPERTIES

Another mechanism that controls production is the relationship of gas content to sorption isotherm. The sorption isotherm defines the relationship of pressure to the capacity of a given coal to hold gas at a constant temperature. Gas content is a measurement of the actual gas contained in a given coal reservoir. A coal reservoir is under saturated if the actual gas content is less than the isotherm value at reservoir temperature and pressure. Accurate measurements of both gas content and the isotherm are required to estimate the production profile of the well.

5. 2. 3 MAINTAINING LOW BACK PRESSURE ON WELLS

The ultimate recovery of gas depends on gas content and reservoir pressure. Gas production will not initiate until reservoir pressure falls below the point where the gas content of the coal is in equilibrium with the isotherm. Because most coal reservoirs are aquifers, production of water from the well bore is the primary mechanism of pressure reduction. If the gas content of the reservoir is below the isotherm, then the reservoir will produce only water initially. After this single phase flow period, bubble flow initiates when reservoir pressure reaches the saturation point on the isotherm. Eventually, two phase flow of gas and water occurs as pressure is further reduced in the reservoir. Because of the relationship between gas desorption and reservoir pressure, it is important to produce coal bed methane wells at the lowest practical pressure. Coal can be called unusual in the sense that it serves both as source rock and the reservoir.

The two most important parameters in evaluating a coal bed methane prospect are: -

- The gas deliverability of the reservoir.
- The total gas-in place

The above two parameters are determined largely by the physical properties of the coal. The petrology and the geology of the coal are the important properties that either directly or indirectly influence gas-in-place and gas deliverability for CBM reservoirs.

5. 3 THE PETROLOGY OF COAL

Coal petrology is the study of the origin, occurrence and structure of coal. Coal is a readily combustible rock containing more than 50% by weight and 70% by volume carbonaceous material. It includes inherent moisture formed from compaction, enduration and diagenesis of various altered plant remains. Coals are classified on the basis of differences in the kinds of plant material (type), degree of metamorphism (rank) and the range' of impurity which are inherent characteristics of coal. The significant differences between coal and conventional reservoir include the greater compressibility of coal, relatively low effective porosity of coal and adsorption of gas on coal's carbon structure.

5. 4 THE ORIGIN AND FORMATION OF COAL

Due to burial, compression and dewatering of the organic material peat is formed initially. It is a dark brown residuum produced by partial decomposition and disintegration of plants that grow in masses and swamps. As a peat is buried more deeply, heat and pressure progressively drive off water and volatiles. 'Through this de-vitalization peat changes into coal due to increase of carbon content of the fossil organic material. During this coalification process, rank of the coal increases from lignite to sub bituminous, bituminous and anthracite. It is the coal rank and the relative abundance of various components, which determine most of the physical and chemical properties of coal.

5. 5 PHYSICAL AND CHEMICAL PROPERTIES OF COAL

As by definition, coal is not a unique substance, but rather a group of sedimentary rocks comprising mainly of altered vegetal matter, it is a heterogeneous mixture of components. Therefore, physical and chemical properties may vary significantly from seam to seam and over a short distance within a seam.

The coal is usually classified by three fundamental characteristics: -

- *Grade* : Represents the relative percentage of organic to mineral matter
- *Type* : It represents the various organic constituents.
- ***Rank***: It represents the level of maturation reached through metamorphism, ranging from peat to anthracite.

The composition of coal is usually described by performing its proximate and ultimate analysis. **The proximate analysis** provides the percentage of fixed carbon (FC), volatile matter (VM), moisture (H_20) and ash content of the coal .

An ultimate analysis provides the chemical make up of the coal as percentages of carbon, oxygen, hydrogen, nitrogen, sulfur and ash.

Physical properties which are useful for evaluation of coal for CBM production are density, porosity, strength, permeability, compressibility, fixed carbon (or heating value) and rank parameter as reflected by its reflectance (R). Several of these properties differ significantly from most conventional reservoir rocks. These include: lower affective porosity, lower density, stress-dependent permeability, higher compressibility and lower Young'. modulus. It is only because of these differences and other characteristics that reservoir simulators have been developed specifically for modeling CBM production.

Coal density is highly useful in accurate estimation of coal resources.

Because of porous nature of the coal, it is difficult to accurately determine its volume and its density. Therefore, apparent density is measured rather than true density. The density of coal reaches a minimum at about 85% carbon in low volatile bituminous range.

Porosity in coals is that portion of the total coal volume, which can be occupied by water, helium or a similar molecule. Porosity for coals of medium-volatile bituminous through anthracite rank is typically less than 5%.

The size of pore spaces ranges from cleat fractures to intra-molecular interstices. Coal pores can be classified into three sizes: -

- Macropores (>500 A),
- Mesopores (20 to 500 A) and
- Micropores (8 to 20 A).

Pore size, pore volume and hence porosity decreases with rank through low-volatile bituminous coal. This trend of porosity decrease with rank into the low-volatile bituminous stage and then its increase is due to loss of additional volatiles,· leaving pore spaces open.

The macro-porosity in coals generally includes cracks, cleats, fissures, voids etc. Gas in excess of that which can be adsorbed is present as "free gas" within this porosity. Gas being slightly soluble in water at the typically encountered reservoir pressures and temperatures of CBM wells also occurs in dissolved state in these macro-pores.

Coal rank is one of the most important characteristics because it directly influences the gas storage capacity of the coal and indirectly the production performance through influence on permeability. Several factors that influence the rank are the type of the organic matter, depositional setting, pH, temperature, reducing potential, depth of burial and time of burial.

The three chief levels of coal rank are:

- Lignite, a brownish-black coal in which the alteration of vegetal material has proceeded further than in peat, but not so far as sub-bituminous coal.
- Bituminous, variety of soft coal which bums freely with a flame and yield volatile matter when heated, and
- Anthracite, a hard black lustrous coal with 92 percent or more fixed carbon. The permeability of these coals is usually very low.

Most commercial CBM projects are in coals within the rank range of sub-bituminous to low volatile bituminous. Coal of this rank usually provides optimum gas content and natural permeability.

As coal rank is mostly influenced by temperature, pressure and length of burial; it increases with depth. But coals at similar depths frequently do not have the same rank due to other variables.

Rank is usually inferred from vitrinite reflectance, fixed carbon value and the heating value. All these parameters increase with rank.

5. 6 COAL CLEAT AND PERMEABILITY

A prerequisite for economic gas flow rates is sufficient coal permeability. Most gas and water through the coal cleat system and other fractures. Cleat is a miners' term for the natural system of vertical fractures which have formed in most coals usually as a result of the coalification process. Typically, the cleat system in coal comprises two or more sets of sub parallel fractures, which are oriented, nearly perpendicular to bedding. The set of fractures called the face cleat is usually dominant. The spacing of face cleat fractures may range from one tenth of an inch to several inches. Typically, the butt cleat is perpendicular to the face cleat, but the fractures tend to be discontinuous and non-planar. Butt cleats commonly terminate against face cleats.

Cleat spacing greatly influences coal bed permeability. Cleat spacing is related to rank, petrographic composition, mineral matter content, bed thickness, and tectonic history. In general, at any given rank, closer cleat spacing is associated with brighter coal, less mineral matter, and thinner beds. This correlation means that most medium and low-volatile coals will have good permeability if the cleats are open. Permeability can be low to non-existent in semi-anthracite and anthracite coals because of the destruction of the cleat.

Mineral fillings in cleat may also lead to low permeability. If a large proportion of the cleats are filled, absolute permeability may be extremely low, as is the case in parts of the Bowen Basin in Australia and western parts of the Black Warrior Basin in Alabama. Common minerals in cleat are calcite, pyrite, gypsum, kaolinite and illite.

5.7 INFLUENCE OF RANK ON COAL CLEAT

Cleat formation appears to be influenced by shrinkage, stress release, and extensional strain. Shrinkage during the process of coalification may contribute to cleat formation. Cleat is present in coals with a rank of lignite through anthracite and is commonly best developed in low-volatile bituminous rank coals. The increased heat and pressure associated with metamorphism causes plastic flow that usually destroys cleat. The effect of rock flowage can be seen by contrasting the highly developed cleat of most seams of bituminous coals which, in general, show few signs of flowage, with the relative absence of cleat in anthracite where such signs are abundant.

5. 8 GAS IN COAL

Much research has been conducted on gas resources in coal - the composition of coalbed gas, gas retention by adsorption, and the gas content of coals. However, probably the least understood aspect is the generation of coalbed gas. Because gas generation occurs over millions of years, it cannot be readily investigated. Researchers have estimated the relative volumes of various gases generated during coalification. However, these numbers tend to vary widely, which attests to the level of uncertainty in coalbed gas generation.

5. 8.1 GAS GENERATION AND COMPOSITION

The term "coalbed methane" is not completely accurate because coalbed gas, though composed primarily of methane, includes other gases. When peat is formed, methane and other gases are produced, first by anaerobic fermentation, bacterial, and fungal alteration, and later in the process of coalification by geo-mechanical alteration through heat and pressure. The gaseous hydrocarbon generated in greatest quantity is methane. Very small amounts of ethane, propane, and butane are also created during peat formation. Because of the low pressure in the swamp environment, nearly all of these gases escape during peat formation. The processes of peat formation and coalification increase carbon in the coal because of the loss of hydrogen and oxygen in the expelled moisture and volatiles. Because much of the volatiles that are produced escape, their volumes are uncertain. Volatiles produced include water (H_20), carbon dioxide ($C0_2$), methane (CH4), nitrogen (N2), and heavier hydrocarbons. More of these volatiles are retained during coalification than during peat formation because of the higher pressures from overlying sediments.

Moisture content decreases as coal rank increases. Thus, most of the water produced during coalification (in addition to original moisture) is expelled from the coal. Humic material, which makes up peat, is composed largely of oxygen-rich lignin and cellulose. Because of the chemistry of a humic coal material, its hydrogen loss will be less than that for sapropelic material. Coal more readily adsorbs CO_2 than CH_4, but CO_2 is more soluble in water. Thus, the retained volume of CO_2 tends to decrease and CH_4 increases as water is expelled during coalification.

5. 8. 2 GAS RETENTION BY ADSORPTION

One characteristic that makes coal reservoirs different from conventional gas reservoirs is the manner in which the gas is stored. In conventional reservoirs, the gas exists in a free state in the pores of the reservoir rock, and thus the real gas law can describe its behavior. In contrast, nearly all of the gas in coal exists in a condensed near liquid like state because of physical sorption. Gases also are present in coalbeds as free gas within the pores or fractures, and/or dissolved in solution (ground water) within the coalbed. Porosity exists in coal as fracture porosity and matrix porosity. Matrix porosity largely determines the ability of coal to retain methane.

Most hydrocarbon gases in coal seams are retained by physical adsorption to the coal molecular hydrocarbons are retained because they are less mobile than methane. Physical adsorption is caused by weak attractive forces (Vander Walls forces) that exist between pairs of molecules or atoms. Such weak physical forces cause adsorption of methane to coal. Adsorption increases non-linearly with pressure and is reversible by increasing the temperature be decreasing the pressure.

The sorption capacity of coal can be determined by adsorption testing. Isotherm tests are conducted at a specified moisture content or at equilibrium moisture and at the formation temperature or an assumed temperature. If the reservoir temperature and pressure are known, an isotherm can be used to estimate the maximum amount or methane that might be adsorbed in the coal, the pressure at which desorption will start (if gas content is known), and the amount of methane remaining in the coal at an assumed abandonment pressure.

5. 8. 3 METHANE CONTENT OF COAL

The methane content of coal can be estimated or measured using a variety of procedures. The most commonly used method is the U.S. Bureau of Miens, Direct Method. Other methods are sometimes used to estimate gas content if there is no active drilling on a prospect. These include estimation from depth and rank relationships.

Very low gas contents can occur near faults if gas has desorbed from the coal and migrated from the strata through a fault or fracture system. Coalbed depth can also be misleading for estimating gas content. In areas where unconformity is created by erosion of the coal and subsequent deposition of additional strata, depth of the coal will have to be measured as the depth below the permeability.

Standard cores usually provide the most reliable gas content estimates. Other types of samples such as side wall cores, drilling cuttings, chips etc. are sometimes used for desorption tests. However, these type of samples are not as reliable as standard cores.

5. 8. 4 EVALUATING GAS CONTENT OF COAL

Gas is retained in coals mostly by adsorption. Adequate desorption tests are performed to verify not only the amount but also the quality of the gas in the coal. The presence of the other gases , primarily C02 is determined by analyzing gas samples during desorption tests.

5. 9 COAL MACERALS AND RELATION TO GAS CONTENT

There are three general maceral groups (litho-types) in coals- vitrinite, liptinite and inertinite. Internal surface area is highest for vitrinite, moderate for liptinite and lowest for inertinite. Hence vitrinite rich (bright) coals have highest capacity of methane retention by adsorption. Further, the methane sorption capacity decreases through part of the medium and low-volatile rank and then increases again for higher rank coals.

5.10 GEOLOGIC LABORATORY ANALYSIS

The correlation of gas desorption data with other petro-physical parameters can be useful in the preparing economic resource development strategies. If core is oriented, fracture mapping techniques can be used to develop estimates of cleat trends and as a result, differential directional permeability trends. Fracture mapping may also offer an opportunity to assess directions of maximum horizontal stress at depth, a factor of importance in simulation of hydraulic fracture treatment; and in placement of wells.

Cleats are a major gas migration pathway in coals. Cleated coal reservoirs can be analyzed in much the same way that conventional fractured reservoir characteristics are determined. Large format thin sections (2" x 3") are also prepared from sections of coal samples that have been impregnated with a fluorescent epoxy resin. Observation of these thin-sections under reflected UV light reveals the cleat and micro-fracture networks. The high degree of feature resolution offered by this technique improves the understanding of the abundance, degree of interconnectivity, apertures and degree of mineralization of these gas migration pathways in coals.

Proximate/ sulfur/ Btu analyses are recommended on a selected suite of samples for each coal study. These data, together with measurement of vitrinite reflectance are useful in determining the rank of analyzed coal. The data are also needed for the normalization of coal gas content to an ash-free and moisture-free basis. Normalized data are useful in the comparison of gas yield from different locations.

5.11 RECOMMENDED PRESSURE TRANSIENT TESTING PROGRAM

One of the primary reservoir properties that controls the production of natural gas from coal seams is the absolute permeability of the natural fracture system. At the present level of technology development. collection and interpretation of well test data is that only means of accurately estimating in-situ natural fracture system permeability. The purpose of obtaining the estimates of the absolute permeability along with other reservoir properties is to predict the production rates of fluids from the coal gas reservoir under a variety of operating conditions. The interpretation of the well test data must be combined with the interpretation of geologic wireline log, core, and fluid property analyses to obtain sufficient information for proper description of the distribution of reservoir properties.

Permeability and production rate estimates are also required to determine the proper method for completing production or injection wells. The goal of well completion technology is to effectively connect the wellbore to the coal natural fracture system to achieve maximum fluid deliverability and recovery. The magnitude or the absolute permeability controls whether maximum fluid productivity can be achieved through the usage of open-hole completions or cased-hydraulically fractured completions. Open-hole productivity may be further improved through the use of dynamic injection and production sequences to improve wellbore-fracture system connectivity. Hydraulic fracturing of open-hole intervals may also be required. Well completion design depends on permeability and other rock and reservoir property estimates such as in-situ stress, coal and non-coal rock compatibility with injected and produced fluids, and the vertical proximity of the coal seams among others.

Conducting a properly designed test involves installing pressure gauges which will monitor and record surface and down-hole pressure changes that occur as a function of time and now rate. In addition, production or injection rate measuring and recording equipment must be properly installed and operated and/or supervised during the test. Data collection is a manpower intensive operation that requires proper supervision and coordination by trained technicians.

The analysis of the data involves comparing the measured reservoir pressure and flow rate response to the response computed by mathematical reservoir models. Once a model has been found which properly predicts or matches the measured data, accurate estimates of the reservoir properties have been achieved. In recent times, the analysis procedures have been greatly assisted and augmented by the use of computers to reduce the required analysis time. Computer based analysis also allows the analyst to use history matching techniques to investigate the application of a wide variety of reservoir models to data interpretation.

The use of reservoir simulation to match short term production rate and bottom hole pressure performance results in estimates of the porosity, pore volume compressibility and calibrated relative permeability behavior of the natural fracture system as well as water production rates. Ultimately, core analysis, well test and simulation derived estimates of reservoir properties are combined with estimates of reservoir volume to predict the gas and water production rates and cumulative recovery that will result from additional field development.

Typical test procedures for a cased well include the following. Similar tests are possible for open-hole wells or newly drilled exploration wells.

- Move in a workover rig and pull the rods and tubing. Recomplete the well, if required, into the desired intervals.
- Run a full bore injection logging tool into the well and perform a gradient survey to determine the current liquid level and to measure the initial pressure in the well.
- Rig up an acidizing unit and monitoring van and inject filtered (l or 2 micron filters) formation water containing 1 % potassium chloride (KCI) at a rate of 0.25 barrels per minute for a period of four to eight hours. The total injection volume will be 60 to 120 barrels.
- Use the injection logging tool to identify the intervals that accept injection.

Once injection logging is completed, suspend the tool at a constant depth and monitor the pressure behavior at one minute intervals while continuing to inject water.

At the conclusion of the injection period, shut-in the well for a minimum of 16 hours (up to 48 hours) to conduct a fall off test. Remove the test equipment and reinstall the original tubulars as desired. Analyze the test data with modern well test analysis techniques based on diagnostic graphs and matching of the observed pressure response.

The information that is desired to design an injection test is listed in the following table. Much of this information will not be available. The items that are critical are shaded. A well bore completion diagram or the drilling and completion reports are required for information concerning tubular sizes. Cement bond logs should be reviewed to determine the bond quality.

5.12 FIELD DESORPTION ANALYSIS & MEASUREMENT OF GAS VOLUMES

Quantitative coal gas resource and reserves analyses depend on the accuracy of formation evaluation data used for reservoir simulation and forecasting. Coal gas reservoir deliverability depends on the gas-in-place and on the gas storage and movement characteristics. Reliable estimates of these depend on knowing in-situ gas content and desorption behavior. Desorption describes the physical mechanisms by which gas is released as reservoir pressure is reduced. Many accepted procedures for collection and interpretation of gas content data are incomplete, and therefore coal gas reservoir simulation input data and the resulting reserves estimates are impacted.

The development of guidelines for desorption are essential for providing the industry and the research community reproducible and comparable gas content and gas-in-place resource estimates. The use of gas content and desorption data to develop economic gas production strategies is technically feasible by measuring the volume of, and rate at which, gas is released from recovered coal samples (desorption).

5.13 FEASIBILITY STUDIES OF SEISMIC METHOD IN CBM

The applicability of Seismic method has been discussed and experimented outside India. Vertical seismic profiles of a coal-bed methane test well near Red Deer, Alberta provide useful data regarding the physical properties of the coal and its suitability for development. In seismic exploration, a mini truck-mounted Vibroseis unit is an appropriate source for imaging coal seams at a depth of approximately 300 m, yielding much higher resolution data. Ardley coal zone contacts at the Red Deer site may be effectively imaged and surfaces within the coal may be detected using the high-frequency source. [Richardson, S.E., Lawton D.C., 2002, Deffenbaugh, M., Shatilo, A., Schneider, B., and Zhang, M., 2000.]

A site in Alberta, near Red Deer, has been selected to test enhanced coalbed methane (ECBM) production using CO_2 injection into the Ardley coal zone. The late Cretaceous Ardley coal zone has CBM reserves estimated at 52 TCF and gas contents ranging from 2.0 to 5.5 cc/g throughout the province of Alberta (Beaton, 2003). At the test site, the Ardley coal is at a depth of 290 m. Dewatering and gas injection, the necessary steps in ECBM, affect the bulk density and seismic velocity within a geological formation. These changes in density and velocity in turn alter the amplitude and travel times of seismic reflections (Richardson and Lawton, 2002). Seismic monitoring of the ECBM pilot project includes vertical seismic profiles of each test well, cross-well surveys, and repeated this surveys over the site.

The first test well was drilled in December, 2002, with accompanying vertical seismic profiles shot in January, 2003. Attribute analysis of this VSP data provides useful information regarding the physical properties of the coal and thus, its suitability for CBM development. This data may provide insight into shear-wave anisotropy and thus orientation of fractures

The Bowen Basin contains the largest coal reserve in Australia. This major coal producing region contains one of the world's largest deposits of bituminous coal. The Basin contains much of the known Permian coal resources in Queensland. A fundamental assumption in seismic reflection processing is that the spikes comprising the earth's reflectivity series are randomly distributed in time, and hence exhibit a white (flat) power spectrum. The validity of this assumption is examined via spectral analysis of log data from the Amadeus, Surat and Bowen Basins, Australia. Reflectivity spectra generated over entire wells from each of these basins are distinctly non-white, supporting observations from previous overseas studies. Typically such whole-well spectral slopes range from 0.5 in the Bowen Basin, up to 1.5 in the Surat Basin, a somewhat broader range than observed in previous investigations. A more detailed analysis of spectra within individual geological formations has also been undertaken. It has previously been suggested that non-repetitive, randomly-bedded sedimentary rocks might be expected to possess whiter reflectivity spectra than more cyclic sedimentary deposits. In the Amadeus and Surat Basins, spectral slopes are typically moderate to high in sandstone formations, while smaller slopes are found in formations comprising finer-grained materials. In the Bowen Basin, formation spectra exhibit a greater range of slopes as a consequence of coal seams occurring in a variety of stratigraphic relationships with other lithologies. For example, thick composite seams comprising interbedded coals and shales can generate very steep spectra. Conversely, thin isolated coal seams have a strong whitening influence on spectra. Whilst such coal-seam related influences may be obvious in log data, not all controls on formation spectra are evident in the time domain.

For Indian scenario, mutliple Gondwana coals seams ranging in thickness from 1-40m are distributed over a large stratigraphic column of about 700 m. Depth of occurrence of Barakar Coals seams range from 250m to 1200m. (AOI for the research work) Conventional Seismic tools does not have adequate resolution to detect & identify characteristics of individual coal seam. Though, through seismic studies, coal and non-coal packs can be identified. In Durgapur area Seismic (high resolution 2D-seismic) data were acquired, no individual coal seams could be obtained. But data was useful for having a feel of overall geological setup of the area.