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The Nature of Gas in Coal: Technical Challenges of Co-Location of Coal and Coalbed Methane

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SUMMARY

The activities involved in the exploration for and production of Coal Seam Gas differ significantly from those employed in the conventional petroleum industry, both onshore and offshore. The difference is not simply one of scale. Generally coalbed methane wells are more closely spaced; drilling techniques and drilling equipment employed are very different; and of course the co-location of coal and coalbed methane resources introduces a dimension that does not exist in the conventional petroleum industry.

There are a number of commonly asked questions about coalbed methane. What is coalbed methane? How does it form? And how does it occur in coal? These questions will be addressed in the paper. Together with how is coalbed methane produced and measured? How much is there? And who owns the methane? Who has priority, coal miners or coalbed methane developers? How does coalbed methane affect coal mining? Has the coalbed methane industry arrived in Australia? What factors will affect the growth of the industry?

INTRODUCTION

The coalbed methane industry is blossoming in Australia. One of the main reasons for this is that 95% of current contracted gas is controlled by just two major joint ventures that are producing from maturing fields in the Cooper Basin and Bass Strait. Gas customers are looking for alternate supplies of gas. Alternate supply sources are being developed including offshore Otway Basin, Papua New Guinea and Timor Sea, but uncertainty exists with these developments primarily due to high capital cost of development.

Natural gas is a growing source of energy in Eastern Australia. Demand is forecast to increase from 600PJ/a to 1,200 PJ/a by 2020. The main drivers for this

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growth are substitution occurring for coal due to environmental constraints and the high fuel costs.

The Australian coalbed methane sector appears on course to follow the USA development where current coalbed methane production exceeds 1,600 PJ per year. Clear development advantages exist around coalbed methane development in Eastern Australia, including the close proximity of the resource to users and infrastructure, improving technology and production history which is reducing the uncertainty of market support plus the environmental benefits of gas.

This paper reviews the fundamental technical issues of coalbed methane. What is coalbed methane? How does it form? How does it occur in coal? What units of measurement are used? How does coalbed methane production affect coal mining? These fundamental technical issues will be addressed to better understand the interaction issues that are currently occurring where coal mining and coalbed methane production overlap.

TECHNICAL ISSUES OF COALBED METHANE GENERATION

What is coalbed methane? How does it form? And how does it occur in coal?

Coalbed methane is natural gas or methane (CH_4) that occurs in coalbeds. It is generated during the conversion of plant material to coal (the process known as coalification). Methane is a tasteless, odourless, colourless non-toxic gas. Compared to conventional natural gas, coalbed methane has relatively few impurities.

During coalification, plant material that accumulates and is preserved in ancient swamps is converted to peat as much of the water in the original material is expelled. Through time the temperature and pressure increases with further burial and ever-increasing ranks of coal form, starting with lignite, followed by sub bituminous coal and bituminous coal as shown in Figure 1 below.

At these different stages of coalification, various hydrocarbons (called volatiles, including methane), along with carbon dioxide, nitrogen and water are released. Increased temperatures throughout burial drive off the volatile matters. Biogenic methane (that attributes to bacterial activity) is first to form, when the temperature exceeds that in which the bacteria can live, thermogenic methane forms (Figure 2 below). Much of the methane generated by the coalification process escapes to the surface or migrates into surrounding rocks. The portion trapped in the coal itself is primarily absorbed within micropores of the coal.

Macroscopic examination of coals from coal mines or coal core samples reveal that coal is naturally fractured with a closely spaced fracture system (called cleats) which forms in response to the coalification process. The coal cleat system is generally orthogonal with one direction cross cutting the other. The dominant cleat is commonly called the face cleat, and the cleat orientated roughly perpendicular to the face cleat is called the butt cleat.[1]

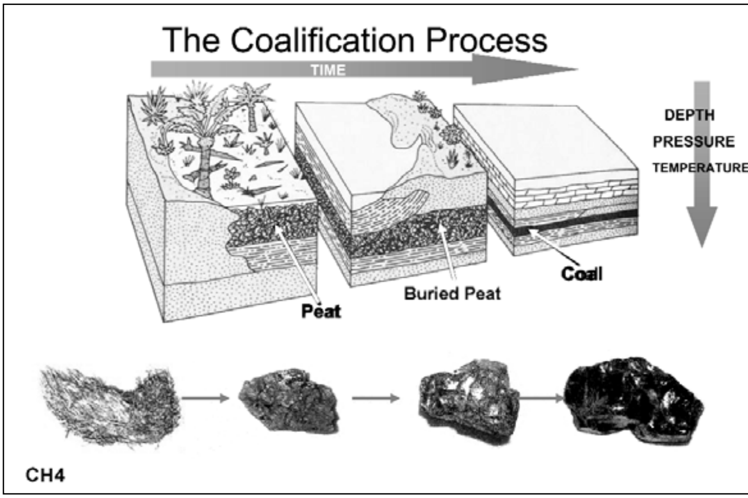

Figure 1: *During coalification, plant material that accumulated in ancient swamps is converted to peat as much of the water in the original material is expelled. Through time the temperature and pressure increases with further burial and ever-increasing rank of coal is formed, starting with lignite, followed by sub bituminous coal and bituminous coal.*

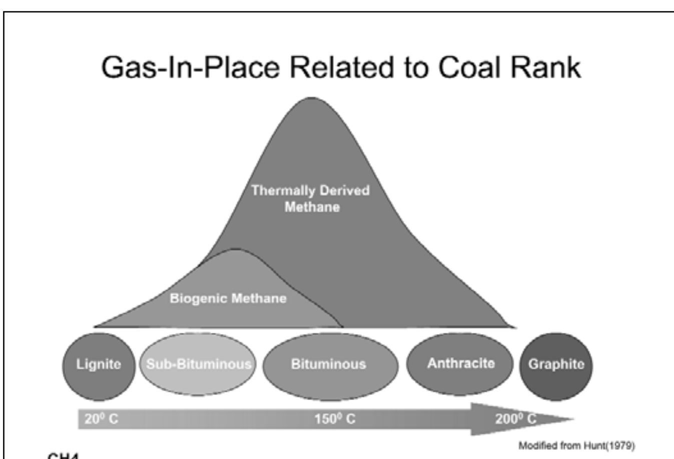

Figure 2: *The stages of coalification, with various amounts of hydrocarbons (called volatiles, including methane) along with carbon dioxide, nitrogen and water being released.*

Coal also contains a very fine "micropore" structure with pore diameter typically ranging from five to 10 Angstroms. This micropore structure has a very low flow capacity (permeability in the microdarcy range), whereas coal cleats

1 Michael D Zubes, "Basic Reservoir Engineering for Coal – A Guide to Coalbed Methane Reservoir Engineering" GRI – 94/0397, Chicago, Illinois (1996).

have a much greater flow capacity (permeability in the millidarcy range). This dual porosity system[2] is shown schematically in Figure 3.

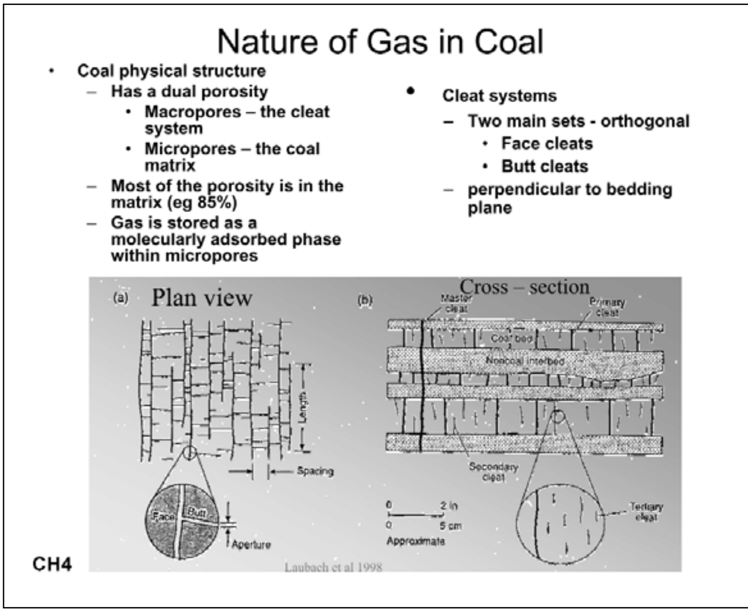

Figure 3: *The physical structure of coal with macropore cleat system and micropore matrix.*

Gas can exist in coal seams in two ways. It can be present as free gas within the joints or fractures and it can be present as an absorbed layer on the internal surface of the coal.[3] The fine micropore structure of the coal has a very high storage capacity for methane. Gas production from coal seams occurs by a three stage process in which gas:

(a) flows from natural fractures;
(b) desorbs from cleat surfaces;
(c) diffuses through the coal matrix to the cleats.

This process is shown in Figure 4 below.

As pressure is reduced in the cleat system by production of water from the gas well, gas desorbs into the cleat system. At this point, and for the remainder of the life of the producing well two-phase flow occurs in the cleat system. This process is represented in Figure 5 below. Under two-phase flow conditions the permeability relationships between gas and water controls the relative flow of gas and water in the reservoir.

[2] J E Warren and P J Root, "The Behaviour of Naturally Fractured Reservoirs" (1963) *Society of Petroleum Engineers Journal* 245-255 (September).

[3] I Gray, "Reservoir Engineering in Coal Seams: Part 1 – The Physical Process of Gas Storage and Movement in Coal Seams" SPE Reservoir Engineering (February 1987) pp 28-34.

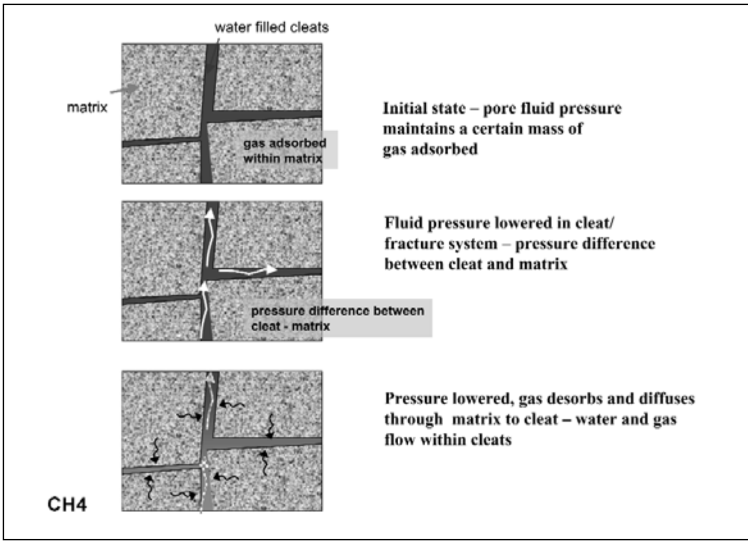

Figure 4: *The gas production process from coal as the fluid pressure is lowered in the cleat system. Gas desorbs and diffuses through the matrix of the coal to the cleat surface and flows with the water through the cleat system.*

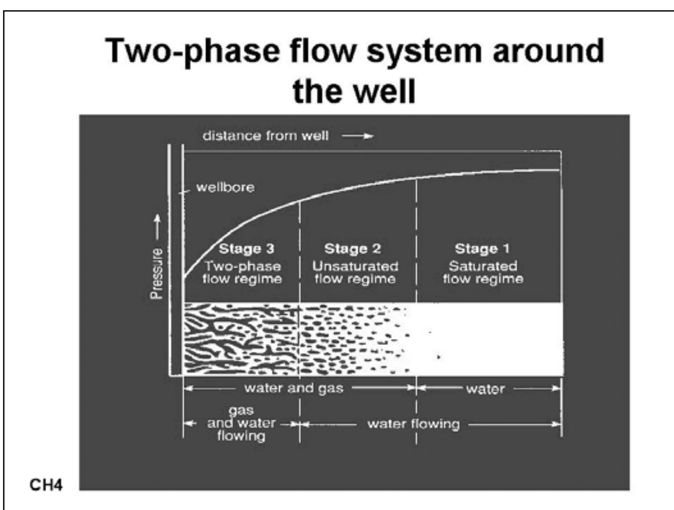

Figure 5: *A typical two-phase flow of water and gas around a well as the pressure is reduced in the cleat system by production of water from the gas well.*

For most coal seams, the quantity of gas held in the coal is primarily a function of coal rank and the pressure of the coal seam.[4] This relationship is best described

[4] I Gray, "Reservoir Engineering in Coal Seams: Part 1 – The Physical Process of Gas Storage and Movement in Coal Seams" SPE Reservoir Engineering (February 1987) pp 28-34.

using a Langmuir isotherm. Figure 6 shows typical desorption isotherms as a function of coal rank.[5]

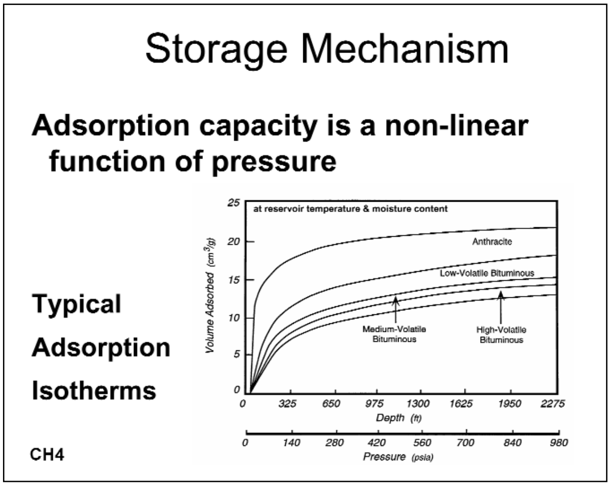

Figure 6: *Typical desorption isotherms as a function of coal rank.*

To estimate coalbed methane gas in place you must determine both the gas content of the coal as it exists at initial reservoirs conditions and the desorption isotherm, which describes how much methane will be released as the pressure is reduced. Both variables must be obtained from exploration core analysis.

A typical production profile of coalbed methane well is shown in Figure 7 below. This profile differs significantly from the typical decline of a conventional gas well. The inclining gas rate in the early life of the well corresponds with a decreasing water flow rate.

In a coal reservoir the water must be removed from the cleat before the gas can effectively flow to the well. The length of the dewatering process and the magnitude of the producing rates of gas and water are controlled by the physical properties of the coal, which are:

- the permeability of the coal (spacing and continuity of the fracture system)
- amount of gas stored in the coal (gas content)
- the interaction between the gas and water (relative permeability)
- propensity of the coal to release the gas (desorption isotherm).

The well spacing will affect the degree of interference which occurs and consequently the gas rate and recovery.

[5] A C Kim, "Estimating Methane Content of Bituminous Coalbeds from Absorption Date" US Bureau of Mines Report of Investigation, RI 8245 (1977).

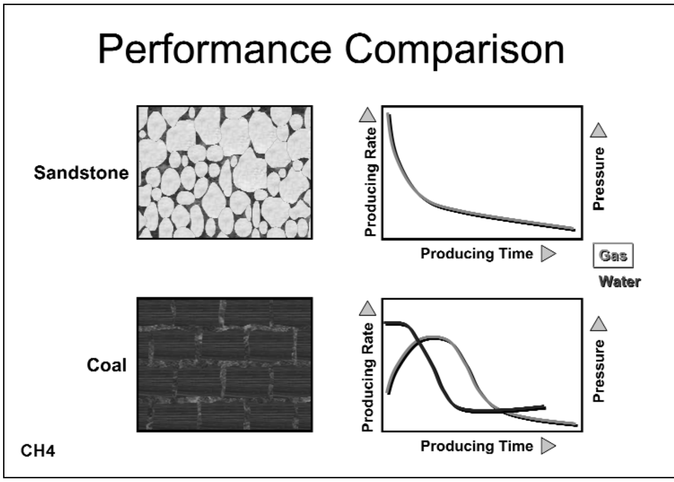

Figure 7: *A typical production profile of coalbed methane well where inclining gas rate in the early life of the well corresponds with a decreasing water flow rate. This is compared with a sandstone conventional gas well.*

MEASURING COALBED METHANE, RESOURCES & RESERVES

Reserves of coalbed methane are the core business for E&P companies. Funding them, developing them, producing them and generating cash flow with them is fundamental to business success. Standardisation of reserve reporting is important. This enables companies to communicate with the market, allows investors to make accurate relative comparison between projects and companies and provides an even footing and basis for good investments.

The gas resource and reserve terminology adopted by the oil and gas industry is presented in Figure 8 below. The gas reserves and resources of any field or basin will include discovered and undiscovered resources. The discovered category is further categorised into contingent resources (non-recoverable) and commercially recoverable resources, which are subdivided into cumulative production and reserves. Reserves are either proved or unproved reserves which include the probable and possible reserve categories.

Increasing certainty occurs as additional data are gathered on gas and resources of a field or basin. The prospective resources of a new basin (a basin with limited data) can be converted to contingent resources which include those gas resources that don't have a market, require a brand new technology for development or don't have a development plan, to reserves which are commercially recoverable either as proved reserves that have a reasonable certainty with current conditions of being recovered to probably and possible reserves which have less certainty with future conditions and expected development. This process is shown diagrammatically in Figure 9 below.

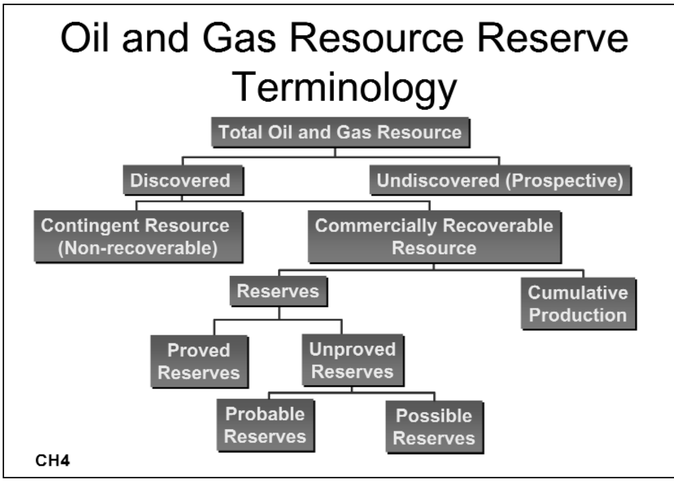

Figure 8: *The resource and reserve terminology adopted by the oil and gas industry.*

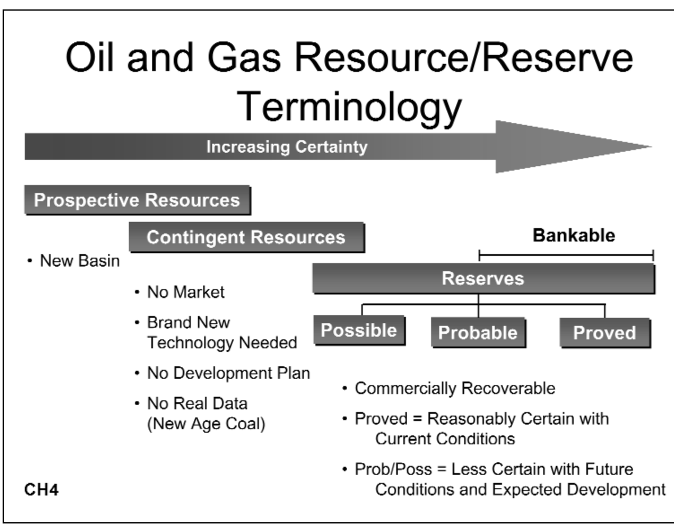

Figure 9: *The process of increasing certainty of resources and reserves as additional data are gathered on gas and resources of a field or basin.*

Proven Reserve (1P or P90) should be reasonably certain with a 90% probability of producing at least the bookable amount. Figure 10 below shows the three categories of reserves, 1P, 2P and 3P.

Business decisions are often made and appropriately so on the basis of "most likely or expected case" – which is generally close to a 2P or P50 which has a 50/50 chance of producing the bookable amount.

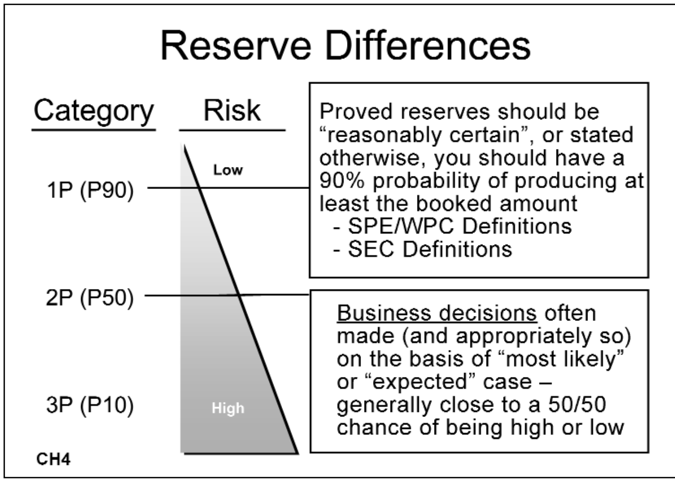

Figure 10: *The three categories of reserves 1P, 2P, and 3P.*

The two main authorities recognised by the industry for categorisation of reserves are the Society of Petroleum Engineers (SPE) and the World Petroleum Congress (WPC).

The SPE/WPC proved definition of reserves are those reserves that may be classified as proved if facilities to process and transport these reserves to market are operational at the time of the estimate and there is a reasonable expectation that such facilities will be installed. Reserves in undeveloped locations may be classified as proved undeveloped provided:

(a) the locations are direct offsets to wells that have indicated commercial production;
(b) it is reasonably certain such locations are within the known proved productive limits of the coal seam;
(c) the location conforms to existing well operating regulations; and
(d) it is reasonably certain the locations will be developed.

The SPE/WPC definition of probable reserves may include:

(a) reserves anticipated to be proved by normal step-out drilling where subsurface control is inadequate to classify these reserves as proved;
(b) reserves in formations that appear to be productive based on well log characteristics but lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area;
(c) reserves in an area of the formation that appears to be separated from the proved area by faulting and the geologic interpretation indicates the subject area is structurally higher than the proved area;
(d) reserves attributable to a future workover, treatment, retreatment, change of equipment, or other mechanical procedures, where such procedure has not been proved successful in wells which exhibit similar behaviour in analogous reservoirs; and

(e) incremental reserves in proved reservoirs where an alternative interpretation of performance or volumetric data indicates more reserves than can be classified as proved.

Reserve evaluation methods accepted by SPE and WPC are either deterministic methods which use known geological, engineering and economic data to generate the single best estimate of reserves, or probabilistic methods which use geological, engineering and economic data to generate a range of estimates and their associated probabilities.

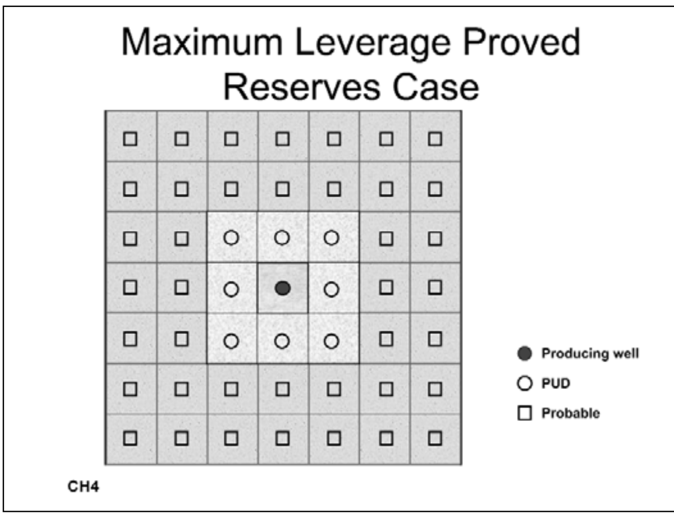

Figure 11: *The maximum leverage of proved reserves that SPE and WPC will permit.*

Coalbed methane reserves and resources are categorised as follows:

Reserves:

- demonstrate coal volume, gas content (OGIP), permeability, ability to de-pressure (peak rate), and economic development;
- in established basins, analogy and performance may be sufficient to establish proved reserves;
- in new basins or plays, need project specific data on above parameters to categorise as reserves – reserve uncertainty (per well quantity, areal, etc) captured in reserve categories.

Resources:

- projects without defined gas market or existing gas contract;
- projects with data supporting OGIP but data not available yet on expected recoveries, flowstreams, etc;
- projects without defined development plans and/or funding.

MINING COAL AND PRODUCING COALBED METHANE

The co-location of coal and coalbed methane resources introduces a dimension that does not exist in the conventional petroleum industry. There are financial, operating safety and environmental benefits to both the petroleum and coal tenure holders to work together in overlapping tenure situations.

Listed below are some of the benefits to miners, gas producers and the State to work together.

Benefits to miner:

- *Reduction in cost:* Extraction of gas prior to mining can reduce mine costs.
- *Acquisition of geological information:* Horizontal drilling for gas a powerful exploration tool.
- *Improved mine safety:* Reduced gas content results in safer workplace.
- *Development of gas gathering and processing:* Provides access to markets for the mine gas.
- *Reduction in greenhouse gas:* Extraction of gas in overlying and underlying seams.

Benefits to gas producer:

- Access to additional gas resources.
- Exploration by miners have delineated gas potential.
- Access to geological information.
- Shared exploration costs and data.

Benefits to state:

- Optimising development of both gas and coal.
- Royalty payments from gas and coal.
- Reduction in greenhouse gas.

Risks to miner:

- *Water, gas or air inrush into mine:* Implement drillhole abandonment procedure.
- *Mining through horizontal hole risk of explosive mixture, ignition from static borehole liners and connection to surface:* Maintain hole surveys and develop procedures.

- *Steel drill pipe or casing left in coal:* Use fit for purpose equipment; no steel casing across minable seams; accurate survey of lost items.

CONCLUSION

The two businesses, gas extraction and coal mining can work closely together: gas extraction from surface; coal mining underground. Timing is perfect with the new *Petroleum and Gas Act 2005* (Qld) for cooperation between miners and gas companies experienced in gas production to join forces.

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