

More than Davy Lamps and Canaries – Coal Seam Methane in the 21st Century

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Summary

Coal Seam Methane as an Energy Source

Coal seam methane (CSM) is a perfect substitute for conventional natural gas. It is found in NSW and Queensland black coal deposits (Victoria's brown coal is not considered prospective) and appears set to become Australia's pacesetter energy growth resource.

Its contemporary commercial development stems from improved extraction technology and increased demand bringing higher gas prices. It had previously been commercially unattractive because of its inherent geological features – including its relatively low concentrations.

CSM is prone to self-ventilating when disturbed and, until recently, the gas was regarded as a menace. In the late eighteenth century, the Davy lamp's invention contributed to the safety of underground coal mining by allowing illumination without a naked flame igniting fugitive CSM. Its notorious lethality was previously countered by safeguards that included keeping canaries in mines. The birds' deaths gave an early warning of the presence of methane in quantities that are potentially lethal to man.

CSM is held in the cracks and crannies of the coal – called “cleats” – and is held in place by the presence of water in the coal. Extraction occurs as the water is progressively pumped out of the coal. CSM typically emerges at a pressure of about one twentieth that of natural gas and each well also normally produces a daily volume of only five per cent of a natural gas well.

CSM has offsetting advantages to the cost penalty entailed by its relatively low concentration levels where it is located close to markets. Transportation over vast distances can undermine the economics of a gas source. Even the 800-1400 kilometres from Longford and Moomba to Sydney entail costs of 65-90 cents per GJ on top of the wellhead wholesale price of around \$3.00 per GJ.

There are other aspects of CSM which tend to reduce its relative costs. First, it is more easily explored and its lower pressure and greater proximity to the surface involves considerably lower cost per production facility. Secondly, the smaller production base reduces risk and allows a more incremental investment program compared to that involved in bringing a major new natural gas development on stream. Thirdly, in the case of Australian resources, the impurities in the coal seam methane are usually less than those in natural gas and the concentration of the methane is also somewhat higher.

Past and Future Growth in CSM

Having been almost unknown as an energy source a quarter of a century ago, US tax breaks provided the original impetus for the development of CSM. These tax concessions have now expired but US CSM developments have continued to grow due to technology induced cost reductions and higher gas prices. Over the past decade CSM comprised almost 60 per cent of increased US natural gas production and now accounts for one tenth of total gas used.

Although benefiting from US technological advances in CSM extraction, Australian production has not enjoyed substantial government subsidies. Those in place largely derive from greenhouse gas abatement considerations. They include Queensland policies, requiring energy retailers to source 13 per cent of their electricity usage from natural or CSM gas fired generators.

Overall growth of gas use in Australia has been rapid. Between 1980/1 and 2000 the share of gas in Australian energy increased from 12 per cent to 20 per cent. The share of CSM within aggregate gas use has been rising. In 2000/1 coal seam methane comprised some six per cent of Australian gas production. ABARE expects this to be 8-9 per cent (60 PJ) in the current year and forecasts 100 PJ per year by 2020, when it would comprise some 12 per cent of Australian gas production.

Other authorities suggest an even faster rate of growth. Work commissioned for the February 2004 prospectus for CH₄ Gas Limited projected at least 25% of Queensland's total natural gas supply (100 PJ in 2004) to be sourced from CSM¹.

Australian CSM inferred reserves at some 275,000 PJ, are in excess of conventional natural gas reserves (estimated at around 160,000 PJ). This is comparable to reserves in the USA, the world's dominant producer of commercial CSM.

CSM is in strong competition from natural gas as well as from other energy sources. One important competitive project under consideration involves piping gas south to Brisbane (and perhaps beyond) from PNG.

The choice of energy source comes down to basic economics. A natural gas deposit located near a main population centre or on an established, underutilised pipeline is likely to provide cheaper gas than any CSM source. But CSM from coal close to the surface and located hundreds rather than thousands of kilometres from major markets will normally offer cheaper delivered energy.

¹ Prospectus for Initial Public Offering 20 February 2004

Introduction

Coal seam methane (CSM) is predominantly methane, a light hydrocarbon gas which is also the primary constituent of conventional natural gas. CSM, sometimes referred to as Coal Bed Methane (CBM), is a perfect substitute for conventional natural gas.

CSM appears set to become the energy industry's pacesetter growth resource. Its commercial development is almost solely confined to the past two decades. Prior to then it was commercially unattractive because of its inherent geological features – including its relatively low concentrations and its likelihood of self-ventilating when disturbed.

Indeed, until recently the gas was regarded as a menace. In the late eighteenth century, the Davy lamp's invention contributed to the safety of underground coal mining by allowing illumination without a naked flame igniting fugitive CSM. Its notorious lethality was countered by several safeguards, including the companionship with miners of canaries. The birds' sensitive respiratory characteristics ensured their deaths could be relied on by miners to give prior warning of the presence of methane in quantities that are potentially lethal to man.

A combination of factors has converted the demon into a seraph. These include an increased value of gas as an energy source, better technology for defining and extracting it and concerns to reduce potential greenhouse gas enhancing emissions of methane.

As a country in which some of the world's most significant coal fields are located, Australia is well placed to take advantage of CSM's re-evaluation. Australian CSM resources, at some 275,000 PJ, are in excess of conventional natural gas resources (estimated at around 160,000 PJ). Australian CSM resources are, in fact, comparable to those in the USA, the world's dominant producer and pioneer of commercial CSM.

Features of Coal Seam Methane

CSM is found in all types of coal since it is a product of the development of coal from primordial organic material. The principal constituent of CSM is the hydrocarbon methane (around 95%). It will also contain some water vapour and may contain small amounts of non-flammable gases such as carbon dioxide and nitrogen (less than 3%) and trace amounts of oxygen and other gases.

Natural gas comprises contains a large proportion of methane (around 90%), heavier hydrocarbons, such as ethane, propane and butane together with small amounts of non-flammable gases such as water vapour, carbon dioxide and nitrogen (less than 3%) and trace amounts of oxygen and other gases.

CSM is held in the cracks and crannies of the coal – they are called “cleats” – and is held in place by the presence of water in the coal. The methane is said to be “adsorbed” on the surface of the coal in the cleats. The process of extraction of the methane, called “desorption”, occurs after the water is progressively pumped out of the coal. The coal

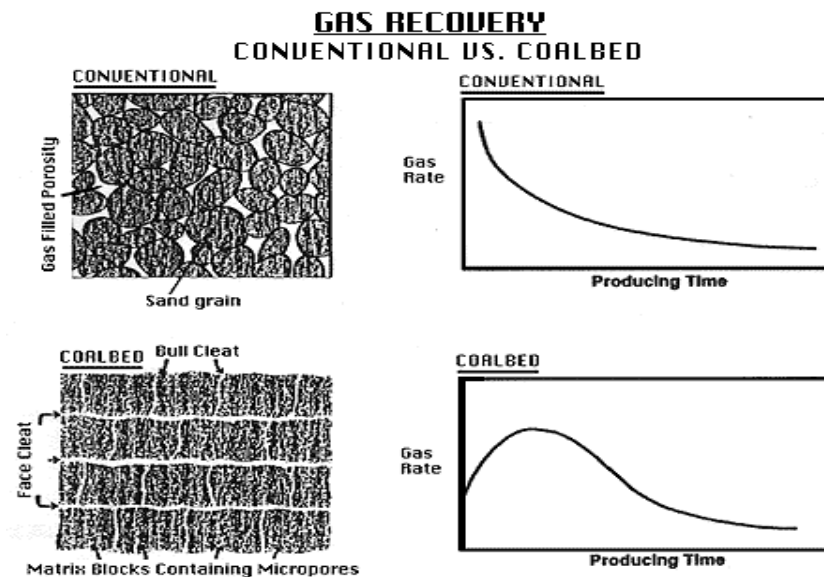
seam methane is produced at relatively low pressures of around 300 – 500 kPa. Gas production from a CSM well increases as the water from the coal seam is pumped out and then plateaus while water production decreases. Most CSM wells produce around 0.5 TJ/day (0.5 MMcfd). Usually, gas can be produced from a CSM well for 5 to 7 years.

Conventional natural gas is held at high pressure in the pores of sandstones and other porous rocks at depths up to 5,000 metres. Natural gas can be delivered to the surface at high pressure (7,000 – 15,000 kPa) when these strata of porous rock are penetrated by a drill hole. Conventional gas can be delivered at high rates during the early life of the well – 10 to 20 TJ/day (10 – 20 MMcfd), but production rates decrease over time as reservoir pressure falls and a well becomes uneconomic in around 5 years or so.

Before being used for industrial or commercial purposes, both CSM and conventional natural gas must be processed to remove their impurities. The treatment of CSM is quite simple – once the water vapour is removed the gas is ready to be compressed into a pipeline network and used by industrial and domestic consumers. Conventional natural gas usually requires more comprehensive processing, during which large quantities of carbon dioxide and heavy hydrocarbons are removed.

Figure 1 shows the differences between the ways in which conventional natural gas and CSM are held in the geological structures below the surface and compares the rates of production from the two different types of gas wells.

Figure 1 Reservoir characteristics for conventional natural gas and CSM



Because CSM wells produce gas at low pressure – inadequate to drive the gas through extensive gas gathering system that services many wells – small electric motor driven compressors take the gas from the wells and deliver it to the gas processing plant, where further compression lifts the pressure to levels required by long distance gas transmission pipelines.

The very high pressures under which conventional natural gas usually emerges from its wells is adequate for delivery of gas to a processing plant and often sufficient for delivery into a long distance gas transmission pipeline. As reservoir pressures fall after a few years, gas gathering system compressors are required.

While CSM requires more wells and more extensive gas gathering and compression systems than conventional natural gas, for an equivalent gas production rate, a review of the costs of each reveals total life costs for each source of natural gas can be quite similar.

As far as industrial and commercial customers are concerned, the quality and “burnability” of CSM is equal to that of conventional natural gas.

This interchangeability between natural gas derived from CSM and natural gas derived from conventional sources allows about 25% of Queensland’s total natural gas supply (100 PJ per year in 2004) to be sourced from CSM, with a further 12 PJ per year to be brought on stream by CH4 Gas Limited and Enertrade in early 2005². Both the Roma to Brisbane and Wallumbilla to Gladstone Pipelines carry co-mingled gas from both sources. Their operators are indifferent to the source of the gas and have experienced no different operational problems resulting from natural gas derived from CSM.

Production Techniques and Economics of CSM

Producing CSM

Generally, for conventional natural gas production, a well is drilled vertically into the gas production zone and gas flows up the well, driven by the high pressure of a gas reservoir which is two or three thousand metres below the surface. The large quantities of gas – around 10 TJ (~10 million cubic feet) per day – means such wells can be spread out, several kilometres apart, over the gas bearing structure. These production wells will continue to produce gas until the reservoir pressure falls below certain minimum pressure of around 2500 kPa. Sometimes it is necessary for the gas production zone to be cracked (called “fracking”) to promote the flow of gas from more distant parts of the gas field to the production well. This process adds substantially to the cost of production.

By contrast, the developer of a CSM field has a number of production techniques at its disposal and which must be chosen to match the characteristics of the coal and its geology. Early in the development of CSM in the Bowen Basin, serious errors were made in the selection of drilling and production techniques, which resulted in high costs and some damage to CSM’s reputation. One observer noted at the time that the developers had failed to heed the warning that “All coals are different”, and expected that conventional oil and gas drilling techniques could be applied.

² CH4 Gas Limited, Prospectus for Initial Public Offering 20 February 2004

The techniques that have been tried and found to be successful in the Bowen Basin include:

- Vertical wells using lower cost oil drilling techniques and air “fracking” – Fairview region

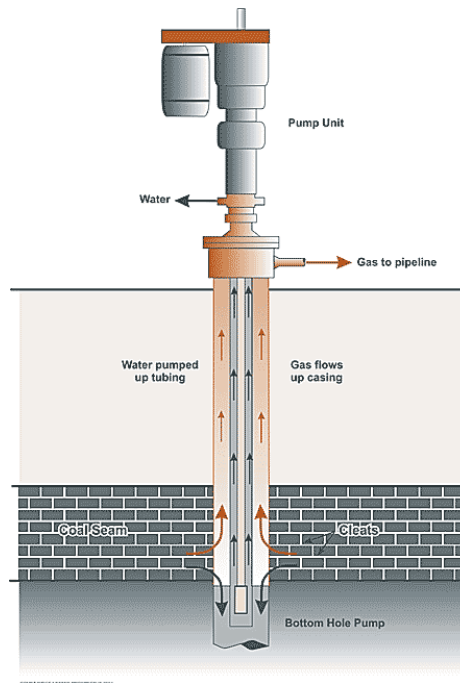


Figure 2 Vertical gas production well

Source: <http://www.cometridge.com.au>

- Horizontal drill holes in coal seam from high wall (exposed coal face in open cut mine) – Moura region
- Horizontal directional drills in coal seam intersecting vertical drill hole

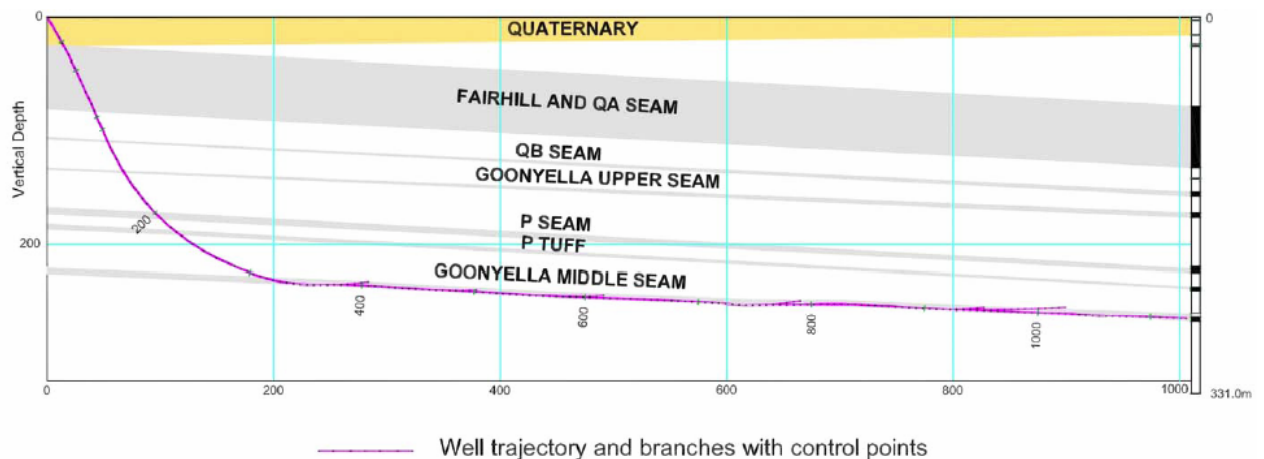
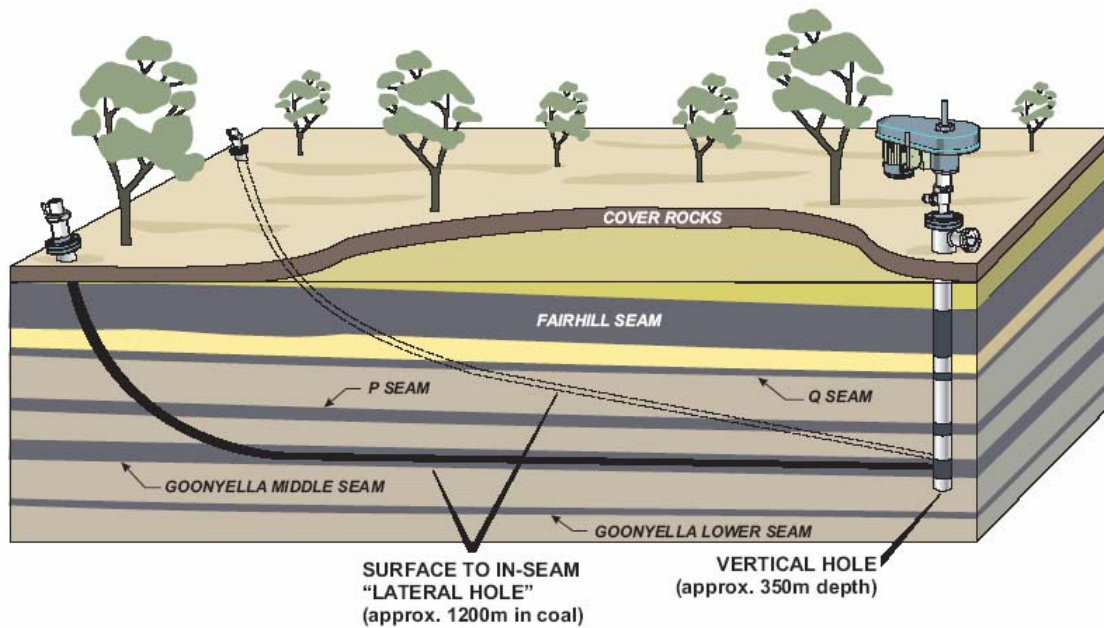


Figure 3 Simplified sketches of HDD in seam intersecting vertical production well
 Sources: CH₄ Gas Limited Prospectus February 2004; Dave Mathew, CH₄ Gas Limited paper to PESA October 2003 entitled *The North Queensland Power Project – A Joint Case Study*

Assessing the Relative Costs of CSM Production

The properties inherent in CSM and conventional natural gas deposits have important implications for their development costs. Because natural gas is found at high pressure, and often in large reservoirs, it can be delivered at a faster rate than CSM. The latter usually requires a larger number of wells to tap the equivalent quantities and may require

additional compressor expenditure to facilitate its movement. Hence, at least until recently CSM production from each source has tended to be low and variable hence its economic viability is often dependent on its location being relatively close to an existing pipeline.

Location of any energy resource is a very important consideration. Transportation of gas over vast distances can undermine the economics of a particular source. Even the 1400 kilometres from Moomba to Sydney and the 800 km from Longford to Sydney entail costs of 65-90 cents per GJ on top of the wellhead wholesale price of around \$3.00 per GJ. Tariffs on transcontinental pipelines could easily be at least two to three times that amount depending on the volumes carried. CSM resources in the coal fields of NSW and Queensland that are close to major markets (and existing pipelines) offer substantial transport economies.

The production cost disadvantages of CSM are also mitigated by other factors. These include the lower cost of most CSM wells and their typically shallower reserves. A further feature of the economics of CSM deposits is that they can be developed incrementally – and compared with a deep, complex conventional natural gas project, at a lower capital cost. Moreover, once the lowest cost conventional natural gas resources have been developed, cost differentials between the two gas types tend to narrow.

It is also inaccurate to discuss CSM (or, indeed, conventional natural gas) as having a constant cost structure. As the “rank” of the coal increases the quantity of methane (all other things being equal), so the quantity of CSM per tonne of coal increases. Most coals in the various sedimentary basins in Queensland and New South Wales contain relatively large amounts of methane

There are other factors which determine whether coal contains commercial quantities of methane. Firstly, the coal must be present in good quality thick (greater than about 2 metres) seams. Secondly the coal must have been subjected to geological maturation conditions of temperature and pressure that will generate methane yet not be such as to drive out the methane or oxidise it.

The type of coal, whether it is bright or dull, will affect the amount of gas generated and also the internal micro-porosity which enables the coal to hold the gas (in much the same way that a sponge holds water). Coal which is rich in the bright maceral vitrinite has been shown to have a greater capacity to absorb gas, but is slower to release gas through desorption, than dull, inertinite-rich coal of similar rank (Crosdale & Beamish, 1993). Balfe 1995³ listed in **Table 1** the most desirable characteristics of coal that would infer commercial quantities of methane.

³ *Coal Bed Methane In Queensland* – Acil Report To M J Kimber Consultants Pty Ltd December 1995

Table 1 Desirable coal properties for CSM

Parameter	Preferred
Coal rank	Low-medium volatile bituminous preferable
Depth (m)	200 – 800
Vitrinite content	Generally the higher the better
Vitrinite reflectance (R_{Vmax})	1.1 - 1.9
Ash content	Low as possible
Volatile matter content	14 - 31% adb
<i>In situ</i> gas content (m^3/t)	10+
Methane content of gas (%)	95+
Individual coal seam thickness (m)	3+
Aggregate seam thickness (m)	8+
Permeability-thickness (md-m)	High as possible

The means of best producing CSM depend upon geological and geophysical aspects including. These have their counterparts with conventional natural gas as is illustrated in **Table 2** below:

Whether any or all of these above aspects apply in a particular circumstance, the developer of the CSM or conventional natural gas resource must take into account the geological and geophysical characteristics of the reservoir and manage them efficiently to achieve the lowest production cost.

Table 2 Comparison of characteristics of CSM vs Conventional Natural Gas

Characteristic	CSM	Conventional
Depth of coal seam or reservoir	Usually shallow (≈ 500 metres) and hence small drilling rigs and conventional horizontal directional drilling (HDD) rigs can be used.	Usually 2,000 to 3,000 metres with high formation pressures. Hence full scale oil and gas drilling rigs are required.
Deliverability	CSM wells generally produce between 0.25 and 0.5 TJ/day and hence many wells are required to produce contract requirements.	Conventional natural gas wells usually produce 5 to 10 times more than CSM, so a reduced number of wells are required
Thickness of seam/pay zone	If the coal seam is thin (< 2 metres) the amount of coal intersected by either a horizontal or vertical drill is limited. However, if permeability is good, then gas will flow to the well and limit the number of wells required	If the pay zone is thin, the amount of the production zone intersected by vertical drill is limited. However, if permeability is good, then gas will flow to the well and limit the number of production wells required.
Permeability of pay zone	Where there are wide variations in permeability (e.g. Bowen Basin seams) production technique and well spacing have to be adjusted to suit.	Permeability of a conventional gas reservoir is very important and is one of the most significant determining factors for economic gas production.
Porosity of pay zone	Porosity in coals is linked to the amount of water held in the producing zone and the surface area of the coal cleats available for adsorption of methane. Again, highly variable across the Bowen Basin.	Porosity of pay zone is most important since it determines the available pore volume to contain natural gas at high pressure.
Faults and discontinuities	Like any geological structure, coal seams have discontinuities that have a detrimental effect on gas production. (In the northern part of the Bowen Basin, mineralisation intrusions limit the extent of seam that can be drained from a well. Igneous intrusions can also damage the seams and affect gas quality).	Faults and discontinuities in conventional reservoirs represent serious impediments to development and gas production. Most discontinuities can be assessed by seismic surveys, but they still affect the economics of production.
Gas content	Gas content of coal is measured in cubic metres (at standard conditions) per tonne of coal. Again there are large variations.	Not an important measure for conventional gas, and is more associated with porosity of pay zone.
Recovery Factor - the ratio of gas recovered over the life of the well/field and the total gas in place	This is another important factor that is determined by the gas production process that is chosen. If the appropriate methodology is applied, a recovery factor for Bowen Basin CSM seams is around 70%.	Many factors influence recovery from a conventional natural gas reservoir, but, like CSM, production methodology and rate of production have significant influence. A conventional gas field will have a typical recovery factor of less than 50%.
Water content	The removal of water from the coal seam to produce CSM is an integral part of the gas production process. Initially, the coal is water saturated and becomes less so as the water is pumped out and the gas is produced.	Water is often present as the source of the drive to produce the gas held in the production zone. Water can be produced in small quantities with the gas.
Water quality	Since water is produced almost continuously during CSM production, the proper disposal of water is a priority. The water produced is usually saline, but has not other contamination. Quality of water varies across the Bowen Basin with some able to be returned to lakes and streams, while others are very saline and have to be disposed of in evaporation pans.	Disposal of waste water from slug catchers and gas processing plants is not a serious problem, but, like water from CSM production must be managed in an environmentally responsible way – particularly if the water is contaminated with hydrocarbons.

Coal seam methane production is somewhat less flexible than that for natural gas. A sudden reduction in demand cannot be as readily accommodated by a cessation of output from a well. That disadvantage can however all too easily be exaggerated. In CSM producing areas, gas and water flows can be managed in a carefully planned manner to regulate production flows. Gas flow rates can be reduced while water pumping continues. This will allow full restoration of gas flow in 24 hours. Alternatively, CH₄ has successfully turned off water pumping and gas flow for some days and have found that, upon re-commencement of water pumping, full gas flow capability can be restored within a short time.

It also must be recognised that, except in emergencies, gas nominations and scheduling are planned and implemented well in advance and hence the periods of time required to adjust water pumping and gas flows are readily managed. In fact, conventional natural gas wells also suffer from lack of flexibility. If they are turned off or allowed to produce high flow rates in excess of the optimum, damage can occur to the producing zone (formation damage) or water can intrude into the region at the bottom of the well.

Both CSM wells and conventional natural gas wells must be drilled, completed and operated according to the dictates of the geological and geophysical conditions that are present. Gas transmission pipelines are designed to be operated to meet the variability of gas demands and supplies. As a result, adjustments to linepack and compressor operations can act as a buffer between the market and the supply.

Environmental Issues and Benefits

Greenhouse Gas Emissions

The greenhouse gas emissions of CSM and conventional natural gas are no different and each produces about one third to one half of the carbon dioxide produced by the burning of coal for an equivalent amount of electricity output. **Table 3** provides more details on this aspect.

Table 3 Thermal Efficiencies and Carbon Dioxide emissions for various fuels used for electricity generation

Generation and Fuel Type	Thermal Efficiency (%)	CO ₂ Emissions (tonnes/MWh)
Combined Cycle – Natural Gas or CSM	48 - 55	0.39
Thermal – Natural Gas or CSM	38	0.49
Thermal – Black Coal	35 - 40	0.93
Thermal – Brown Coal	29	1.23

Source: Derived from Australian Cogeneration Association submission to NECA1998

The characteristics of CSM derived natural gas after processing are shown in **Table 4**. Comparisons with the characteristics of processed natural gas derived from conventional sources are shown in **Table 5**. There are no significant differences. This shows that CSM derived natural gas can be co-mingled with, or substituted for natural gas derived from conventional sources without any problems.

Table 4 Typical gas specification for gas sourced from CSM processing plants

Characteristic	Limit
Carbon dioxide	≤ 3%
Water vapour	≤65 mg/cubic metre
Total inert gases	≤6%
Oxygen	≤0.2%
Total sulphur	≤50 mg/cubic metre
Gross heating value	≥35 MJ per cubic metre (if inerts ≤ 4%)
Wobbe index	≥47 and ≤52
Hydrocarbon dew point	≤10°C

Source: Enertrade gas transportation contract

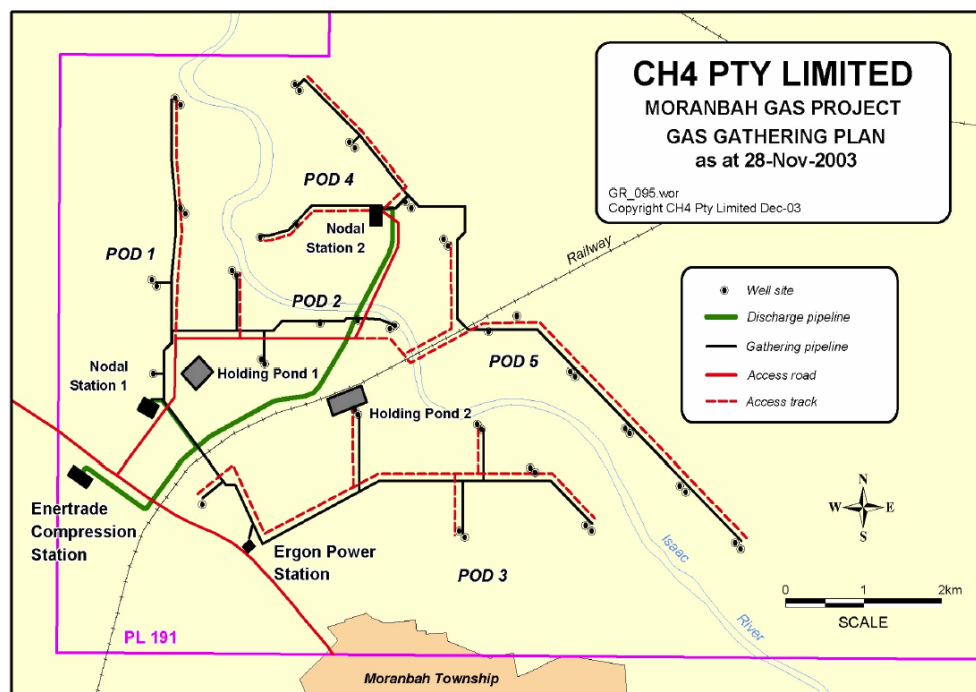
Table 5 Typical gas specification for gas sourced from conventional natural gas processing plants

Component	Category B Gas (no LPG)
Carbon dioxide	≤4.0%
Inert gases	≤6.0%
Higher heating value	≥37.3 MJ/cubic metre
Wobbe Index	≥47.3 and ≤51.0
Total sulphur (Unodorised gas)	≤10.0 mg/cubic metre
Oxygen	≤0.2%
Maximum Water	≤48.0 mg/cubic metre
Hydrocarbon dewpoint	<0°C
Maximum radioactive component	600.0 Bq/cubic metre

Source: Epic Energy DBNGP gas transportation contract

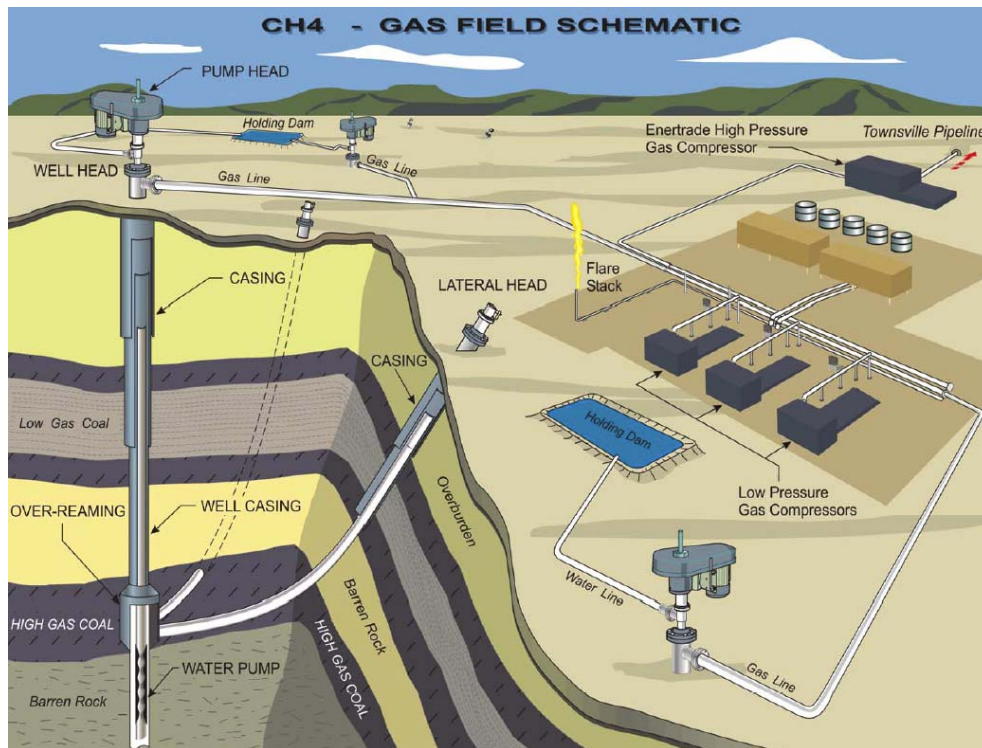
CSM and Local Environmental Issues

Like most oil and gas drilling and production, CSM production steps lightly on the environment. Small areas are needed to be gravelled and fenced adjacent to drill sites at around 1 km spacing and sites need to be established for field compressors. A typical CSM field layout is shown in **Figure 4** and **Figure 5**

Figure 4 Moranbah gas gathering system showing small extent of area affected

Source: David Mathew, CH4 –Project Update, Coal Seam and Mine Methane Development Conference 2003

Figure 5 Pictorial view of CH4's Moranbah CSM production facilities



Source: *David Mathew, CH4 –Project Update, Coal Seam and Mine Methane Development Conference 2003*

Small underground gathering pipelines have to be built from each of the wells to transport the water to a holding tank and gas to the field compressors and on to the gas processing plant. In keeping with normal pipeline practice, the land's surface above the pipelines is restored to its original state. Service tracks to each well and above-ground facilities are required.

Water disposal has been mentioned by many sceptics of CSM, but in all cases of CSM production, water disposal has been managed quite satisfactorily in accordance with the appropriate environmental and water resources legislation.

In the case of CSM production in the Moranbah region, CH4 plans to pipe all its surplus water to the nearby coal washeries which currently use potable water supplied from the Eungella Dam. This will result in considerable cost savings to the coal mines and divert the potable water supplies in the region to higher value uses. In the western Bowen Basin, water that is potable is diverted to creeks and lakes and used for irrigation and stock, while water that is too saline for such use is transferred to evaporation ponds.

In short, the development of a CSM production field is environmentally benign. The field produces the most environmentally friendly fossil fuel for providing electricity and industrial fuels.

Australia's CSM Reserves

Total Australian natural gas reserves (commercial and non-commercial reserves) as at January 2001 were estimated to be 158,539 petajoules (Geoscience Australia 2002). These reserves are almost all located some considerable a distance from the markets they supply. Moreover, apart from the 4,000 PJ in the Cooper/Eromanga Basin, substantial reserves are located offshore in Bass Strait and other areas. By contrast, coal seam methane deposits are located in association with black coal deposits (brown coal is not considered to be as prospective) close to major markets.

CSM as an energy source has been largely sub-economic until the past decade or so and less attention has been paid to evaluating its resource potential. Nonetheless, the known potential available from CSM is considerably greater than that of natural gas. This is in spite of some major coal deposits having not been prospected in sufficient detail to offer reserves estimates.

Table 6 identifies available information on reserves as indicated by ABARE and Origin Energy.

Table 6 Inferred Reserves of Coal Seam Methane in NSW and Queensland

	Billion cubic Metres	PJ
New South Wales	2,559	97,242
Sydney	752	28,576
Gunnedah	732	27,816
Clarence–Moreton	1,075	40,850
Gloucester	na	na
Queensland		
Bowen	4,000	152,000
Surat b	na	25,000 ⁴

In the US, where successful production and exploration were stimulated by tax breaks, the US Geological Survey estimates CSM comprises 141 trillion cubic feet and inferred reserves are 700 trillion cubic feet (cf. total natural gas production of some 22 trillion cubic feet per annum). For these, of necessity speculative estimates, a trillion cubic feet can be equated to a thousand PJ. It can be inferred that the Australian reserve situation is therefore comparable with that of the US.

That said, the issue of reserves and how they are measured is complex and contingent on a great many assumptions. The issue of hydro-carbon reserve measurement has caused considerable embarrassment to the Shell Company over the past year. The Appendix discusses some of the issues and seeks to relate these to Australian CSM circumstances.

⁴ Estimated Origin Energy recoverable reserves

Australian Current and Projected CSM Production Levels

Present Activity

Developments in CSM have coincided with a rapid growth in demand for natural gas in Australia. According to ABARE, “Consumption of natural gas is projected to increase by 3.7 per cent a year over the outlook period (by 4.8 per cent in the medium term). The use of natural gas is projected to double to 1828 petajoules in 2019-20, accounting for 36 per cent of the growth in total energy consumption over the entire outlook period. As a result of this, the share of natural gas in the energy mix is estimated to increase by 5 percentage points to more than 24 per cent by the end of the outlook period.⁵”

Most current Australian production is in NSW and Queensland and, as exploration is also centred on these two states, those two states are expected to remain dominant.

In 2000/1 coal seam methane already comprised some six per cent of Australian production; in the current year, according to ABARE, this is expected to be 8-9 per cent (60 PJ) while by 2020 consumption is forecast at some 100 PJ per year. At that stage on present estimates CSM will comprise some 12 per cent of Australian gas production.

Queensland

Queensland production in 2002 was 25 PJ about 25 per cent of total state demand. Queensland production currently occurs in⁶:

- Fairview (Tipperary Oil and Gas)
- Peat (OCA Ltd), which supplies 5 PJ per annum to BP’s Brisbane oil refinery.
- Dawson Valley (OCA)
- Scotia (Santos) where gas has been injected into the Ballera-Brisbane pipeline since March 2002.
- Moura coal mine (Anglo Coal Australia/Mitsui)

Considerable activity is being conducted within Queensland with the following number of new CSM wells identified:

Year	Exploration	Appraisal/development
Year to June 2000	24	23
Year to June 2001	30	43
Year to June 2002	24	53

The major players are

- Oil Company of Australia; an 85 per cent owned Origin Energy subsidiary, has over 50 producing wells, in 2002 it produced 60 per cent of Queensland CSG or 25 TJ/d (9 PJ per annum)

⁵ M Akmal, S Thorpe, A Dickson, G Burg & N Klijn Australian Energy: National and State projections, 2004.

⁶ www.nrme.qld.gov.au/mines/petroleum_gas/csg/review.html

- TriStar Petroleum Company; present since 1989, had completed 60 wells by 2001/2, producing 20 TJ/d about 7 PJ per annum sent via the Duke pipeline to Brisbane and Gladstone
- Santos; plans further development of Scotia and is exploring Walloon Coal near Roma
- Queensland Gas Company, exploring in the Jurassic coal seams in the Surat Basin
- Tipperary Oil and Gas; drilled 8 wells in 2003 and has associations with Tri-Star
- Arrow Energy; a new company started drilling in 2000 and has exploration interests at Roma and in the Surat Basin
- CH4; forecast to be producing from its half share with BHP at Moranbah at a rate of over 14 PJ per annum by the second quarter of 2005
- Sunshine Gas; started exploration in 2002.

NSW

AGL signed its first contracts to take CSM gas from the output of the first twenty five coal seam methane gas wells to be drilled by Sydney Gas Company NL (SGC) in PEL2 (in the Sydney Basin) for a period of ten years. This was conditional upon the company being able to supply at least 2 PJ per annum.

Planning Minister Mrs Diane Beamer has gone on record as saying the CSM in the Camden region could supply up to 15 per cent of NSW demand⁷.

Eastern Star gas will generate electricity from CSM at Narrabri in the State's west. The Toronto-listed Gastar Exploration has been engaged in exploration in the area since 1998, and has reported possible methane gas reserves of 8.7 trillion cubic feet.

In NSW, the Tower coal mine near Appin started commercial CSM production in 1996. This is utilised by Appin Tower Electric power using 94 one MW engines plus 54 engines at the site capturing fumigant methane.

Forecast Position of CSM as an Australian Energy Resource

In the twenty years to 2020, CSM is expected to have trebled its output to reach the ABARE estimated gas market share of 12 per cent. The ABARE forecasts are reproduced below in **Table 7**.

⁷ http://dipnr.nsw.gov.au/mediarel/mn20040628_2715.html

Table 7 ABARE forecasts of production and consumption of natural gas 2001-2020**Table 5.** Estimated eastern Australian gas supply and demand balance using standard supply assumptions and first reserves scenario^a.

	2000-01 PJ	2004-05 PJ	2009-10 PJ	2010-11 PJ	2011-12 PJ	2012-13 PJ	2013-14 PJ	2014-15 PJ	2019-20 PJ
Production									
Bass	0	20	20	20	20	20	20	20	20
Bowen-Surat	27	13	10	10	10	0	0	0	0
Cooper-Eromanga	226	228	215	213	210	208	205	203	190
Gippsland	236	265	318	336	358	337	345	348	360
Otway	8	63	125	125	125	77	90	77	125
Subtotal	497	588	688	704	723	642	660	648	695
Coal seam methane	34	60	81	82	83	85	86	90	100
Ethane b	36	36	36	36	36	36	36	36	36
Total Eastern Australian Production	567	685	805	822	842	763	782	774	831
Northern supply option	0	0	0	0	0	100	100	129	177
Total Production	567	685	805	822	842	863	882	903	1008
Consumption									
New South Wales	141	173	198	200	203	205	208	211	230
Victoria	236	273	311	317	325	334	341	349	388
Queensland	78	115	135	137	141	145	148	152	177
South Australia	112	117	147	152	158	164	169	174	193
Tasmania	0	7	15	16	16	16	16	17	20
Total Consumption c	567	685	805	822	842	863	882	903	1008

a) The first reserves scenario assumes all non-commercial reserves are upgraded over time to become commercial. b) Ethane from the Cooper-Eromanga and the Gippsland Basins are assumed to be constant over the period based on 1999-2000 production. c) Totals may appear not to add due to rounding.

Some authorities consider these forecasts to be conservative. Ministerial statements have indicated a rather more substantial growth. According to data assembled by London Economics for the CH₄ Prospectus, CSM is expected to comprise some 25 per cent of the gas used in Queensland. London Economics sees much greater upside for gas than ABARE and in Queensland alone estimates gas could comprise 250 PJ per annum.

Government Support for CSM

In the US, CSM has benefited from favourable treatment from governments. US Federal Income Tax relief was afforded under Section 29 of the Windfall Profit Tax Act. In force between 1980 and 2002, this advantaged CSM gas (as well as oil shale and oil tar, biomass, synthetics and certain wood fuels). Over the period it operated it is estimated to have given a credit worth on average \$1.02 per Mcf (\$1.10 per GJ). With wellhead gas prices at \$2, this tax break was critical⁸. It is now expired but prices are now well over \$4 per Mcf and CSM can flourish without a subsidy.

Between 1990 and 1999, CSM accounted for almost 60 per cent of the increase in US natural gas production. By 1999, CSM comprised almost 7 per cent of US gas usage, having been produced in negligible quantities prior to 1990. Production has continued to climb and in 2002 amounted to 1,614 billion cubic feet.

Though benefiting from US technology developments (arguably spurred on by that country's formerly benevolent tax regime), Australian growth has not, in the main, benefited from specific government support measures. Even without subsidies growth of gas use in Australia has been rapid. In overall terms between 1980/1 and 2000 the share of gas in Australian energy increased from 12 per cent to 20 per cent, and more recently, the share of CSM within aggregate gas use has been rising.

As with industry in general, measures are available in the form of R&D tax concessions which allow an additional 25 per cent tax deduction to reduce the actual cost of certain activities. In addition a tax offset ranging between 30 per cent and 52 per cent can be claimed on eligible R&D expenditure.

Australia's most important energy subsidy scheme, the Mandatory Renewable Energy Target (MRET) offers a subsidy which brings up to a \$40 per MWh price increase to eligible electricity sources. Worth some \$380 million per year by 2010, the MRET scheme does not apply to gas.

Gas is however benefiting from government policies in Queensland where, even before gas-specific assistance measures were introduced, gas consumption was experiencing rapid market growth. In 2002 consumption was at 100PJ per year with CSM comprising 25 per cent. Policies more recently introduced include the Queensland Government's proposed legislation requiring energy retailers to source 13 per cent of their electricity from gas generation. This implies a 2004 usage of 20 PJ, (6,500 GWh) a threefold increase over actual volumes used in electricity generation in the State.

Even prior to the introduction of this law, gas was favoured by planning restrictions on the use of coal in powering the Townsville facility. Enertrade is committed to using 12 PJ of CSM annually in the 220 MW Townsville station which is being converted from jet

⁸ see *The Majors' Shift to Natural Gas*, Energy Information Administration, US Department of Energy, September 2001

aviation fuel to gas. The newly listed company, CH4, is to supply this 12 PJ per annum from its Moranbah field which is 50 per cent owned by BHP. The CH4 Prospectus envisages a market of 45 PJ per annum by 2016 in Townsville plus other North Queensland growth that is expected to bring 80 PJ per annum in the next 20 years. Sales prices can be inferred from the Prospectus at \$2.11 per GJ.

There is however competitive rivalry for electricity inputs, not only between gas and other forms of fuel but also from different forms of gas. CSM is in strong competition from natural gas with a major project under consideration to pipe gas south to Brisbane (and perhaps beyond) from PNG.

In addition to the support measures from the Queensland Government, specific project support has been given to CSM from waste coal mine gas by the Australian Greenhouse Office under the Greenhouse Gas Abatement Program. The support is contingent upon the notion of “additionality” in reducing greenhouse gas emissions. It is not intended to offer support for programs that are intrinsically commercial, hence the projects are not significant in the aggregate energy supply. The projects supported and their funding comprise:

- German Creek colliery, Central Queensland: \$15.47 million based on waste coal mine gas. The support is about half of the total project cost.
- Envirogen: GGAP funding would be used to install and operate ten 1MW reciprocating gas engines at each of two coal mines, one on the NSW Central Coast (Teralba), the other in central Queensland (North Goonyella). The equipment will burn methane contained in waste coal mine gas to produce electricity, reducing methane emissions and displacing coal fired electricity generation. *Funding Approved: Up to \$13,000,000 Total Project Cost: \$26,600,000; Expected Abatement: 1.98 Mt CO₂-e during 2008-2012*⁹.
- EDL’s Bellambi mine on the NSW South Coast: methane gas that would otherwise be vented to the atmosphere during the coal mining process will be drained from the coal before it is mined and used to generate electricity. *Funding Approved: Up to \$9,000,000. Total Project Cost: \$16,000,000. Expected Abatement: 1.70 Mt CO₂-e during 2008-2012*
- Centennial Coal, Newcastle: \$15 million has been allocated for the Vales Point power station to capture methane gas for electricity generation.
- BHP Billiton, Illawarra: \$6 million has been allocated for specialised combustion processes at the West Cliff colliery to generate electricity from low concentrations of methane.

A further \$10 million has been provided to the Australian EcoGeneration Association for a range of smaller scale co-generation projects valued at \$67 million.

⁹ In answer to a question in the Parliament, support for Envirogen was listed as being in two rounds between 2004 and 2009 valued at \$9.21 million and \$9.0 million for rounds 1 and 2 respectively. http://www.aph.gov.au/senate/committee/ecita_ctte/quest_answers/addest0304/eh/ago.doc

Royalties and Government Charges

Section 55 of the *Petroleum Act 1923(Queensland)* states:

55 Royalty

- (1) Any person who produces petroleum shall, subject to this Act, pay royalty to the State at the rate of 10% of the value at the wellhead of the petroleum.*
- (2) There shall be set off against the amount of royalty payable in any year under this Act the amount of rental paid under this Act in that year by the producer in respect of a lease of or a permit or authority to prospect granted in relation to the land from which the petroleum in question was produced.*
- (3) Should the amount of such rental exceed, in any year, the amount of such royalty, no royalty shall be payable by the producer in question in respect of that year.*

This implies that both CSM and natural gas sourced from conventional sources attract that same amount of royalty, and hence there is no preference given to one or the other.

However, it should be noted that the NSW Government provides a royalty “holiday” for CSM for the first 5 years from commencement of production where the CSM is derived from a coal mining lease¹⁰. In addition, the relevant Minister of the NSW Government can determine a reduction in royalty¹¹. The relevant legislation in Queensland has no such flexibility.

This may become an issue if gas from the southern Surat Basin, southern Clarence-Morton Basin or Gunnedah Basin in New South Wales is sold into Queensland or comparisons are made between Eastern Star’s conventional and CSM production from the Gunnedah Basin.

¹⁰ Petroleum (Onshore) Regulations (NSW) 2002 - SECT 23 Rate of royalty; Mining Act 1992 section 86

¹¹ Petroleum Onshore Act (NSW) 1991 - S86 Reduction of royalty in certain cases

Appendix 1

Proven and Probable Reserves – the disconnect between CSM and conventional natural gas

There is a constant debate between proponents of CSM and those of conventional natural gas on the vexed question of reserves and the point at which resources become reserves. The traditional oil and gas industry, its bankers and advisers are fixated on the Society of Petroleum Engineers' (SPE) definitions of the various classes of reserves for hydrocarbons. These definitions have been derived by SPE and the World Petroleum Congress (WPC) as a result of a century of experience with oil and gas deposits throughout the world and their traditions are hard to depart from, but there may be a case for some departure from these definitions towards those traditionally more applicable to the coal and minerals industries, since CSM is co-located and intimately associated with extensive coal deposits. The same economic, geological and geophysical drivers apply, whether the coal is to be won for fuel for power stations or export or CSM is to be produced for power stations and general consumption.

To put the SPE categories of reserves in context, the quantities in each of categories are *estimates* and are based on the current state of knowledge of the assessor. The estimates will change (either up or down) as more information about the resource is collected – such as more development drilling and production history.

SPE states¹² that:

Estimation of reserves is done under conditions of uncertainty. The method of estimation is called deterministic if a single best estimate of reserves is made based on known geological, engineering, and economic data. The method of estimation is called probabilistic when the known geological, engineering, and economic data are used to generate a range of estimates and their associated probabilities. Identifying reserves as proved, probable, and possible has been the most frequent classification method and gives an indication of the probability of recovery. Because of potential differences in uncertainty, caution should be exercised when aggregating reserves of different classifications.

The three categories defined by SPE and the World Petroleum congress (WPC) are:

- Proved – often referred to as 1P
- Proved plus Probable – 2P
- Proved plus Probable plus Possible – 3P

SPE defines Proved Reserves as:

Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially

¹² http://www.spe.org/spe/jsp/basic/0,2396,1104_12169_0,00.html

recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorized as developed or undeveloped.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

SPE defines Probable Reserves as:

Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.

SPE defines Possible Reserves as:

Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.

To populate these categories for a conventional natural gas resource, the assessor – usually a petroleum engineer or geologist – reviews drilling, seismic and production data to determine gas in place by a relatively simple volumetric process, assesses probability of more (or less) gas being defined by future drilling, and estimates current and future production rates and costs against benchmarks set by the owner of the resource. Clearly not all gas can be produced from the reservoir and costs will increase as the reservoir pressure falls and/or water infiltrates the reservoir. The assessor takes these matters into account.

A conventional gas reservoir is much smaller in area and volume than a CSM rich coal seam, but contains more gas per unit volume of stratum than a coal seam. As a consequence, much more detailed knowledge of the smaller conventional gas structure is needed to carry out the assessment of reserves. This knowledge can only be assembled by the use of very expensive drilling, extended production test and seismic surveys.

On the other hand, the coal fields that hold Queensland's huge CSM resource are very large and exhibit surprisingly consistent geological structures. They stretch from Collinsville in the north to Roma in the south, and cover 350 to 400 thousand square kilometres. In the region in which CH₄ Gas Limited has commenced CSM production – ATP364 (see map Figure 6) – more than 30,000 exploration holes have been drilled from which CH₄ and its reserve assessors have been able to gather very important geological and geophysical data on such aspects as:

- quantity of gas per tonne of coal;

- depth and thickness of the various CSM rich seams;
- permeability of coal;
- porosity of coal;
- ash content;
- rank of coal; and
- other matters important for assessment of CSM reserves

From these data production plans and methodology can be postulated and reasonable estimates of gas in place and recovery factor can be made to arrive at a reasonable assessment of how the P, 2P and 3P reserves categories can be populated.

However, it is essential to remember that CSM truism – *when considering production methods hence reserves, all coals are different*. As a result there remains a significant amount of empiricism in the determination of production methodology, and this is inevitably closely linked to reserves assessment. In regions in the USA, such as the San Juan Basin, there is a very large volume of information and production history which allows better predictions to be made than are possible in the Bowen and Surat Basins at present. As more history is collected by the operators and the reservoir assessors, better and perhaps less conservative reserve assessments will be able to be made. It is essential that current assessments be revisited each year as production and drilling history are accumulated.

Appendix 2

Example of Reserves Assessment

In its prospectus for its Initial Public Offering and in subsequent announcements to the Australian Stock Exchange, CH4 Gas Limited has published reserve assessments carried out by Netherland, Sewell and Associates Inc. These reserve assessments have been progressively refined as a result of the assembly of more data from drilling and production tests. The area of interest is in PL 191 within ATP364, as shown in Figure 6.

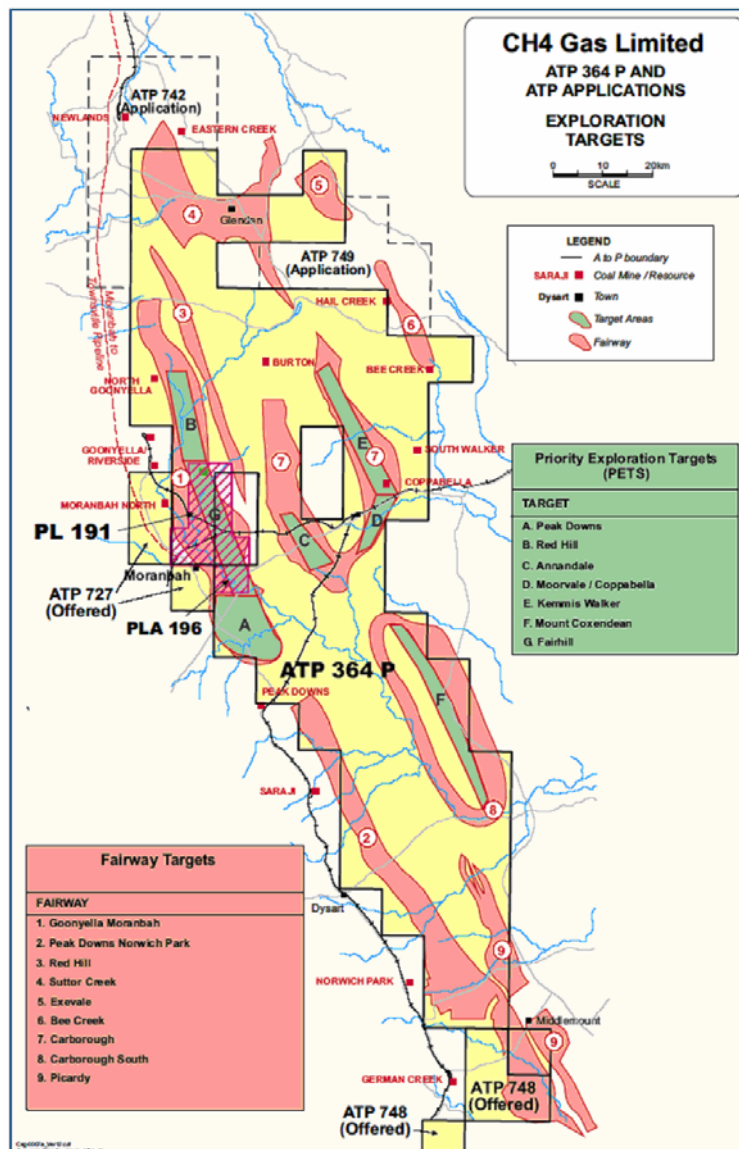


Figure 6 Map of ATP364

Source: CH4 Gas Limited Prospectus February 2004

Prospectus for the IPO for CH₄ indicated as follows:

Netherland, Sewell and Associates Inc apportioned the recoverable gas volumes into Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P) on the basis of commonly accepted criteria, which relate to the certainty of recovering the stated volumes as follows: -

Proved reserves - are limited to the Goonyella Middle coal seam [for location of each seam, see Figure 3] for the three wells drilled as at 1st October, 2002 and the 12 direct offset locations to these wells.

Probable reserves - are in the Goonyella Middle and P coal seams limited to the south-western portion of the lease, where there are sufficient well penetrations and gas content data to accurately estimate gas-in-place and reserves.

Possible reserves - are estimated for the remaining area of the lease in the GM and P seams and for the entire lease in the QB and GL seams

Category/Coal Seam	Original Gas-in-Place		Average Recovery Factor (%)	Estimated Ultimate Reserves		
	(Bscf)	(MMm3)		(Bscf)	(MMm3)	(PJ)
Technical Proved (1P)						
GM Seam	14.4	407.4	77	11	312.4	11.6
Proved + Probable (2P)						
GM Seam	173.7	4,917.90	75	130.2	3,686.80	137.4
P Seam	105.5	2,986.40	67	70.7	2,003.60	74.6
Total All Seams	279.2	7,904.30	72	200.9	5,690.40	212
Proved + Probable + Possible (3P)						
GM Seam	586.4	16,607.10	68	400.8	11,349.50	422.8
P Seam	400	11,328.60	63	251.3	7,115.80	265.1
QB Seam	356.1	10,084.50	56	198.8	5,631.30	209.8
GL Seam	267.3	7,569.90	63	168	4,756.70	177.2
Total All Seams	1,609.80	45,590.10	63	1,018.90	28,853.30	1,074.90

Recent work in the Moranbah region has confirmed these following reserves/resources figures:

Area	Reserve Category	100% Share PJ	CH4 Share PJ
PL 191 (MGP)	1P ¹	11.6	5.8
	2P ²	210.5	105.3
	3P ³	1,074.9	537.5
PLA 196 ^(4,6)			
	2P ²	72.0	36.0
	3P ³	177.3	88.7
Peak Downs ^(5,6)			
	2P ²	104.0	52.0
	3P ³	363.3	181.7
TOTAL			
	1P	11.6	5.8
	2P	386.5	193.3
	3P	1,615.5	807.8

NOTES

- 1 1P= Proved Reserve
- 2 2P= Proved and Probable Reserve
- 3 3P= Proved, Probable, and Possible Reserve
- 4 Not yet granted but, as titleholder of ATP 364P, CH4 maintains a right to the grant of PL application 196
- 5 Application for PL not yet made over this area, but as titleholder of ATP 364P, CH4 maintains a right to the grant of a PL application over reserves in this area
- 6 Under the terms of the Project Agreement between CH4 and BHP Billiton, BHP Billiton may elect to take up to a 50% interest in these areas should CH4 submit a Bankable Feasibility Study (BFS) for the development of these reserves. As at 21 July 2004, a BFS has not been prepared and therefore BHP Billiton has not been required to make any election under the terms of the Project Agreement.

Source: CH4 Gas Limited ASX announcement 22 July 2004