ENHANCED RECOVERY OF COAL BED METHANE WITH CARBON DIOXIDE SEQUESTRATION – SELECTION OF POSSIBLE DEMONSTRATION SITES

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Title: **Enhanced Recovery of Coal Bed Methane with Carbon Dioxide Sequestration - Selection of Possible Demonstration Sites**
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Other remarks:

Background to the Study

The IEA Greenhouse Gas R&D Programme (IEA GHG) is systematically evaluating the cost and potential for reducing emissions of greenhouse gases arising from anthropogenic activities, especially the use of fossil fuels. This study aimed to expand the Programme's range of studies of carbon dioxide storage options, by considering further the storage of CO_2 in deep, unminable coal bed reservoirs, with associated enhancement in the production of coal bed methane.

The IEA GHG Programme commissioned a first global study of the potential for using CO_2 to enhance Coalbed Methane (CBM) recovery, with simultaneous CO_2 sequestration in the coal in 1998[1]. The study concluded that the injection of carbon dioxide into deep coal seams had the potential to enhance coal bed methane recovery, while simultaneously sequestering carbon dioxide. Analysis of production operations from the world's first CO_2-enhanced coal bed methane production, in the San Juan Basin in USA, indicated that the process is both technically and economically feasible. Worldwide CO_2 sequestration potential in deep coal seams was estimated to be around 150 Gt of CO_2, based on the twenty coal basins estimated to have the best potential for CO_2 Enhanced Coalbed Methane (CO_2-ECBM) recovery. Of this total, perhaps 60 Gt of CO_2 may be sequestered at costs of under \$50/t of CO_2 (not including separation and transmission costs). Practical development is also underway in Canada and other countries.

In order to move this technology towards wider acceptance, especially as a CO_2 sequestration measure, it is important there should be successful demonstrations. To facilitate demonstrations outside USA/Canada, a second study on CO_2-ECBM was commissioned in June 1999. This study targeted coal basins in Europe, India, Australia and China. It is hoped that, as a result of this study, other organisations and industry may be stimulated to undertake formal feasibility studies and, eventually, large-scale financing of CO_2-ECBM projects.

An international consortium of companies led by the Alberta Research Council has carried out the second study. The consortia included CSIRO (Australia), Sproule International (Canada) Tesseract Corporation and an independent consultant Joseph Cooper (USA).

Technical Background.

CBM is conventionally recovered by means of reservoir-pressure-depletion, which is a simple, but inefficient process recovering typically only 50% of the gas in place. Recently, two new technologies have been proposed for enhancing coal bed methane (ECBM) production, which are:

- inert gas stripping using nitrogen injection (N_2-ECBM),
- displacement-desorption employing CO_2 injection (CO_2-ECBM)

N_2-ECBM works by lowering the partial pressure of methane to promote desorption and is capable of recovering 90% or more of gas in place in the coal seam. In the CO_2-ECBM process, injected CO_2 is

[1] Report number PH3/3 August 1998

preferentially adsorbed at the expense of the coal bed methane, which is simultaneously desorbed and can then be recovered as free gas. The CO_2 remains stored within the seam providing the seam is never disturbed. Laboratory isotherm measurements demonstrate that coal can adsorb roughly twice as much CO_2 by volume as methane. Early indications from actual applications suggest this ratio might be higher (3 or more) depending on channelling of CO_2 through faults and other high-permeability pathways.
CO_2-ECBM, therefore, is potentially capable of providing storage for anthropogenic CO_2 as well as improving the production of coal bed methane. If the coal is never mined, it is likely that the CO_2 would be sequestered for geological time-scales.

Results and Discussion

The following areas are described in the report:

- Assessments of Australia, China, India and Poland for potential sites
- Ranking of sites in each country
- Technical design of a CO_2-ECBM demonstration site
- Costing of CO_2-ECBM demonstration
- Economic analysis of CO_2-ECBM projects in Australia and China.
- Estimate of CO_2 sequestration costs
- Project financing

Assessments of Australia, China, India and Poland for potential sites.

A geological assessment of these four countries identified the 8 "best" prospective basins for CBM development and then proceeded to select 11 potential sites in these basins for possible demonstration projects. The basins, and potential demonstration sites, are listed in Table 1. The detail of the geological assessment procedure used to rank the sites is given in the report.

Country	Basins Identified	Sites Selected
Australia	Bowen Basin Gunnedah Basin Sydney Basin	(1) Dawson River, (2) Moura, (3) Fairview (4) Durham Ranch (5) Narrabri (6) Camden
China	Ordos Basin Qinshui Basin	(7) Eastern Border (8) Southern sector, Jincheng field
India	Cambay Basin Damodar Valley	(9) Gujarat, in the Mehsana Block (10) Jharia Coalfield in the Parbatpur Block
Poland	Upper Silesian Basin	(11) Former Amoco Block, south of town of Tychy

Table 1 Potential CBM Basins and Demonstration Sites

It was noted that, for the 8 basins evaluated, the amount of detailed information available varied widely. Also, the data within a particular basin indicated that the CBM prospects could vary considerably between sites. The consultant highlighted that this ranking may be subject to revision in future, as more data becomes available for the basins and sites considered.

Ranking of Sites in Each Country

The prospective sites indicated in Table 1 were evaluated and then ranked based on the following five factors:

- Market potential,
- Production potential,
- CBM resource/CO_2 storage potential,

- CO_2 supply potential
- Site infrastructure costs (financeability).

Details of the scoring system used to rank the sites are given in the main report. The overall ranking of the top sites in each country is given in Table 2 overleaf.

Ranking	Country	Basin	Site	Score
1	Australia	Southern Bowen	Dawson River	198
2	China	South Qinshui	Jincheng Field	168
3	Poland	Upper Silesian	Former Amoco block	73
4	India	Cambay	Mehsana	57

Table 2 Ranking of Potential Demonstration Sites

The Bowen basin, Dawson River site in Australia had the highest score followed by the top Chinese, Polish and Indian sites[2]. The Indian site scored lower principally because it was considered to have a lower potential gas market since the gas distribution infrastructure is not well developed in the region. The Polish site's score was low because detailed information on the site was not available and the consultant had to rely on basin average data for the evaluation. The scores of the Australian and China sites were very close. Both the Australian and Chinese sites were considered to have merit and so both were selected for the later economic evaluation exercise.

Technical Design of the Demonstration CO_2-ECBM Site

A three-stage process for development of the demonstration at each site was proposed, which would consist of:
Stage 1: Micro-Pilot Testing - This involves field review, well drilling and evaluation of one injection and production well, micro-pilot testing, data analysis and 5-spot pilot design. Approximately 200 tonnes of CO_2 would be injected over a week into one well.
Stage 2: 5-Spot Pilot Testing - The 5-spot pilot involves drilling four additional wells (one producer and three injection wells)[3], converting the well used in stage 1 to an injector and construction of a surface facility. Approximately 15,000 tonnes of CO_2 would be injected over a six-month period followed by production testing, data analysis and project design. This stage would take two years to complete.
Stage 3: 9-Pattern Testing – The commercial demonstration would then comprise 9 5-spot patterns consisting of 25 producers and 16 injectors, with the existing producer converted to this mode of operation. This would form a 41-well commercial demonstration, with injection of 400 tonnes CO_2 per day or 120,000 tonnes CO_2 per year.

Costing of CO_2-ECBM Demonstration

The demonstration plant capital cost estimates for the two selected sites are given in Table 3.

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[2] This ranking is generally similar with a first principles analysis of prospective coal deposits in the earlier study on CO_2-ECBM reported in PH3/3. The main difference in the rankings was that the Cambay basin ranked second in the previous study because the natural gas market was considered to be more developed than in this study. IEA GHG considers the more recent evaluation of the gas market in India to best reflect the current market status.

[3] Normal commercial practice would be for the 5 spot to consist of 4 producers; the selection of the opposite arrangement by the contractor in this case was deliberate and was based on numerical models of the ECBM process. It was considered that, for the purposes of this test, the methane production enhancement would be more pronounced in this arrangement. The well separation in the pilot was also reduced from normal commercial practise so that testing could be complete within 1 year to reduce costs.

	Dawson River (Australia) $US Million	Jincheng Field, (China) $US Million
Stage 1: Micro-Pilot Testing	0.67	0.73
Stage 2: 5-Spot Piloting Testing	6.2 (net 4.8)	6.7 (net 5.3)
Stage 3: 9-Pattern Testing	35	40

Table 3. Demonstration Pilot Plant Capital Cost Estimates

The accuracy of the cost estimates for Stage 1 and Stage 2 was considered to be +/- 30%. The major uncertainty in Stage 2 is the cost of the CO_2/flue gas generator. There is a possibility that some costs could be recovered (50%) by sale of the compressor and flue gas generator after this test; this option is shown in Table 3 as 'net' costs. The Stage 3 cost estimates are considerably less certain than the other figures; these estimates can only be improved once the reservoir performance data becomes available from the stage 2 work.

Comparison of the cost estimates in Table 3 suggests that the demonstration plant costs (for all three stages) are generally 10% higher in China than Australia. The difference can be explained by the general accessibility of drilling rigs and the costs of well drilling (considered to be some 30% higher in China than Australia) and the cost of well-completion services for the two sites.

Economic Analysis of CO_2-ECBM projects in Australia and China

In order to establish a case for the demonstration projects, an economic analysis has been conducted for commercial-scale CO_2-ECBM projects in each of the chosen locations. In this analysis, it is assumed that land permits will already have been obtained and pilot testing completed for each project[4]. A commercial project will require 50 producing wells initially, with a further 50 wells drilled in subsequent years, each in the centre of an area of 65 km^2. A total of 64 injection wells will also be drilled. For the purposes of this analysis, it is assumed that high quality CO_2 would be available at the project site at pipeline pressure (1,200 psig or 8.27 MPa) at zero cost[5].

For each case study, a numerical model for CBM production was developed based on the local reservoir and coal seam conditions. In the Australian case, the model was developed based on CBM reservoir data from projects in the Dawson River, Fairview and Durham Ranch. For the Chinese site, only limited reservoir data was available publicly, therefore, because the Jincheng basin displayed similar properties to the Bowen basin, the Australian case model was used to predict CBM production from the Jincheng field. The results from the Chinese site must, therefore, be considered as more tentative. The numerical model was then used to predict the methane gas production rate from conventional production techniques at each site. Based on data from the Burlington Resources pilot test in the San Juan basin the rate of methane production from CO_2-ECBM was estimated for both sites. Then using laboratory isotherm data (2 moles of CO_2 adsorbed for 1 mole of CH_4 desorbed)[6] the amount of CO_2 that would in theory be absorbed by the coal to displace the amount of methane

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[4] It was considered that, initially, CO_2-ECBM projects would be located at conventional CBM project sites, to use the existing infrastructure, thereby reducing the investment risk.

[5] For both projects only a limited analysis of available local CO_2 sources were undertaken. In the Australian case only power plant sources were located around the demonstration site, whilst in China both power, fertiliser and steel plant sources were located to the site. Efforts were not made to match the most appropriate (nearest available, highest CO_2 concentration) source to the demonstration sites in this study and determine an actual CO_2 supply cost for each site.

[6] The consultants have acknowledged that initial results from the Burlington Resources pilot have indicated the mole ratio could be nearer 3: 1 CO_2: CH4. It was considered that, without further supporting data, the laboratory isotherm measurements should be used for this study; the different results from the San Juan basin might be due to reservoir hetereogeneities.

produced under CO_2-ECBM conditions was then determined. For both the Australian and Chinese sites the amount of CO_2 injected within the coal seam over the life of the project (20 years) was determined as 28.6 Mt respectively. The calculation has assumed that no CO_2 breakthrough at the producer wells is observed for the duration of each project. A net value of CO_2 injected was also calculated at 18.6 Mt. This value represents the CO_2 that needs to be bought in by the project because some CO_2 will be generated on site (by the recycle compressor for example) which will then be reinjected. Note: In the main report both these values are referred to as sequestered amounts, however, more correctly this should be referred to as injected amounts.

For the Australian case, the economic analysis has shown that the break-even gas price for a conventional CBM project is \$ US 1.0/GJ at a discount rate of 10% before tax[7]; for the CO_2-ECBM project it is \$ US 0.85/GJ. At these gas prices the projected break-even periods were 9.5 and 12 years before tax respectively. For the Chinese projects the breakeven gas prices are \$ US 1.1 and 0.9/GJ for the conventional and CO_2-ECBM projects respectively[8]. The time to break-even at the quoted gas prices were projected to be 8 and 10 years respectively (not including any effects of tax). The project breakeven point is sensitive to gas prices for example at a gas price of \$ 2/GJ the breakeven periods (before tax) for the Australian case are reduced to between 4 and 5 years, making the project look more attractive from an investment perspective. Cash-flow projections for a range of gas prices are given in the main report.

The economic analyses have shown that the CO_2-ECBM process can recover substantial incremental methane at a cost comparable to primary production, provided that the CO_2 can be delivered to the field site at an "affordable price". It was found that the affordable price for the CO_2 ranges from less than zero to US \$ 12/tonne CO_2, for a range of plant-gate methane gas prices from US \$ 0.50 to \$ 3.00/GJ. It is noted that in all cases this cost is far lower than the cost required to capture/separate, compress and transport the CO_2 or flue gas to the field, which is estimated at US \$ 45-55/tonne CO_2[9]. This indicates that, for the CO_2-ECBM process to be economically viable in either of these locations the cost of CO_2 capture must be reduced or a credit must be available for the amount of CO_2 sequestered.

Estimate of CO_2 Sequestration Costs

The levelised cost of sequestration for the CO_2 has been determined by comparing the discounted (10%) net present values (before tax) for the conventional and CO_2-ECBM projects[10]. At a gas price of \$2/GJ the CO_2 sequestration costs at the Australian site were \$ US -4.7/t[11] and at the Chinese site \$ US
-5.0/t. Again these costs are sensitive to natural gas prices.

Project Financing

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[7] Costs in the main report have been presented after tax, for the purposes of this overview IEA GHG's standard assessment criteria have been applied and costs have been presented before tax at a 10% discount rate. Before tax data is available in the Appendices to the main report.

[8] For the detailed economic analysis of the Chinese site, the China United Coalbed Methane Co. Ltd was actively involved in the study.

[9] Cost based on recovering CO_2 from coal-fired power plant flue gas using current amine separation technology. In the report the consultant has used a cost of US \$ 25-35/t for capture, compression and transportation. IEA GHG consider this cost to be too low and, based on current technology, the cost would be nearer US \$ 45-55/t. The inclusion of low capture/compression/transport costs does not affect the report outcome, as these costs are not included in the economic analysis.

[10] Sequestration costs were not calculated by the consultant but have been calculated by IEA GHG against our standard assessment criteria for comparative purposes with other CO_2 sequestration options.

[11] Negative value indicates net income.

In the Chinese case the demonstration pilot would likely be developed as a technology transfer project. The recipient of the technology would be the state-owned company China United Coalbed Methane Co. Ltd. (CUCBM). For Stages 1 and 2 of the demonstration pilot, the financing could come from international development agencies or bilateral funding agencies. When the project goes to Stage 3 - commercial demonstration - CUCBM might continue to finance it or international oil and gas companies might provide financing in exchange for a share of the commercial revenues.

For the Australian project, financing would be likely to come from private industry and, perhaps, Australian Government sources. For example, Stage 1 of the demonstration project might be funded mainly by Government grants supplemented with some industrial funding. Then, as the project proceeded to later stages, energy companies would, hopefully, take more interest and their share of the project financing would increase.

Expert Group Comments

A panel of expert reviewers, some from the CBM industry and some with geological storage expertise, reviewed the study. In general, the study was well received and the comments were complimentary. The report was considered to be a valuable resource/reference document for industry and governments for CO_2-ECBM production in the four countries considered. Many of the comments related to clarification of technical points raised, such as the range of gas sorption capacities quoted, and many were editorial.

One issue raised related to data availability and the impact of this on the country rankings although the Australian case would undoubtedly have come top in any ranking. However, concerns were raised that data limitations meant that the other countries might not have been evaluated as effectively. For example, in Poland, the reviewer cited as an example a Texaco 5-well CBM pilot that was drilled in 1997-1998. However, it is understood that the information from this pilot is proprietary and so was not available to the consultants who undertook this study. It was noted by the consultants that the ranking they produced was subject to data limitations and that, as further data becomes available in the future, the rankings could change. It is felt that the contractor has made their best effort to collect publicly available data from a diverse range of sources.

In relation to the Chinese case a number of concerns were raised about the appropriateness of the selected site. For example, it was felt that the coal in the basin is predominately anthracite; based on US experience this would be considered too impermeable for effective CBM production. The points raised were presented to the CUCBM experts who were actively involved in the study. They indicated that the basin rank varies from bituminous to anthracite and permeability is typically 1-5 milliDarcy, which should be sufficient (see Report PH3/3). Chinese experience suggests the Qinshui basin is one of the most hopeful for CBM and hence CO_2-ECBM production in China.

Every effort has been made by the consultants to address the points raised by the reviewers.

It is noted that the contractors have also provided some economic analysis of the use of flue gas injection (as distinct from CO_2 injection) for comparison with the analysis of CO_2 injection at the two demonstration sites. None of the expert reviewers commented on this aspect of the report. IEA GHG consider that, whilst flue gas injection has potential benefits, the technique has not yet been technically demonstrated as an effective way of sequestering CO_2[12]. Therefore the data on flue gas injection in the report should be viewed with some caution at this stage.

Major Conclusions

[12] The technique of flue gas ECBM is currently being investigated by the Alberta Research Council on a single well pilot in Canada. Results of this work are expected to be available in 2001.

A detailed geological assessment of coal basins in Australia, China, India and Poland has been undertaken. Two potential sites, one in Australia and one in China were selected for further detailed evaluation as potential demonstrations of CO_2-ECBM technology. The cost to undertake a CO_2-ECBM demonstration test at these sites was determined based on a staged project development scenario. The project was assumed to involve three stages. First a single injection well pilot test would be completed, and then a 5 spot pilot test and finally a 41-well commercial demonstration, which would inject 400 tonnes, CO_2 per day or 120,000 tonnes CO_2 per year. The cost of such a phased development project has been estimated at US $ 42 million at the Australian site and US $ 47.5 million at the Chinese site.

The demonstration projects were shown to be economically viable at each demonstration site. At gas prices of $ US 2/GJ, project payback times (before tax) of 4-5 years could be realised, which could be attractive to commercial operators. The projects' economic viabilities are dependent on the natural gas price - higher prices will result in more favourable break-even periods. Conversely, lower natural gas prices will make the project less economically attractive.

Over the lifetime of each potential demonstration project, which is estimated at 20 years, some 28.6 Mt CO_2 will be sequestered in the coal seams at both the Australian Chinese demonstration sites. This equates to a cost of sequestration of between US $ -4 and -5/t CO_2 at these sites. These sequestration costs are consistent with previous work which has indicated that, in favourable basins such as the Bowen Basin in Australia, CO_2 sequestration could generate a small net income when part of a CO_2-ECBM scheme.

Recommendations

The study was designed to assist in facilitating the introduction of CO_2-ECBM technology outside of North America. IEA GHG should publicise the results of this study, in order to facilitate the take-up of CO_2-ECBM technology. Dissemination of the study results could take place via the presentation of papers at relevant conferences and in technical journals.

Consideration could be given to the organisation of dedicated workshops to present the study's findings to interested parties in Australia and China. These parties could include: CBM production companies, potential project developers and financiers including international aid agencies such as the UN, World Bank, Asian Development Bank, etc. Such events would aim to promote the establishment of CO_2-ECBM demonstration projects and thereby assist the take-up of the technology. Technology demonstration projects are also essential to provide confidence in the volumes of CO_2 that can be stored and the safety of CO_2 storage in deep coal beds.

FINAL REPORT

Enhanced Recovery of Coalbed Methane/ Carbon Dioxide Sequestration

IEA/CON/99/52

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Unit Abbreviations and Conversions

Gj	Giga (10^9) joules (1 Gj is approximately equal to 0.95 Mcf of natural gas)
Gm^3	Giga (10^9) cubic meters
Gt	Giga (10^9) tonnes
km^2	square kilometers (1 km^2 = 247.1 acres)
kPa	Kilopascal
m	Meter
m^3	cubic meters (1 m^3 = 35.31 cubic feet)
md	Millidarcy
Mg	Million (10^6) grams (1 metric tonne)
Mt	Million (10^6) tonnes
Mm^3	Million (10^6) cubic meters
MPa	Megapascal
MW	Mega (10^6) watts
PJ	Peta (10^{15}) Joules (10^3 Joules = 0.94845 BTU)
t	tonne or metric ton (1 tonne = 1.102 short tons)
$A	Australia Dollar ($A1.67 = $US 1.0)
$	U.S. Dollar
$ Yuan	Chinese $Yuan 8.3 = $US 1.0

<u>U.S.A. Usage</u>

bwpd	barrels of water per day (1 barrel = 159 liters = 0.159 m^3)
Bcf	Billion (10^9) cubic feet (1 Bcf = 28.3 Mm^3)
HP	Horsepower
Mcf	Thousand cubic feet
Mcfd	Thousand cubic feet per day (1 Mcfd = 28.3 m^3/d)
Quad	Quadrillion (10^{15}) BTU
mi^2	Square mile (1 mi^2 = 2.59 km^2)
MMcfd	Million cubic feet per day
psi	Pounds per square inch (1 psi = 6.89 kilopascal)
Tcf	Trillion (10^{12}) cubic feet (1 Tcf = 28.3 Gm^3)
Bcf/mi^2	(1 Bcf/mi^2 = 10.93 Mm^3/km^2)
Scf/ton	(1 scf/ton = 0.0320 m^3/t)
Psi/ft	(1 psi/ft = 22.6 kPa/m)
Scf	Standard cubic feet (1 scf = 0.0283 cubic meters)
Daf	Dry-ash-free basis
Vro	Vitrinite reflectance, reflectance increases with coal rank
Acre	1 acre = 0.00405 km^2 = 0.405 hectares

EXECUTIVE SUMMARY

CO_2 & N_2 Enhanced Coalbed Methane Production Technology

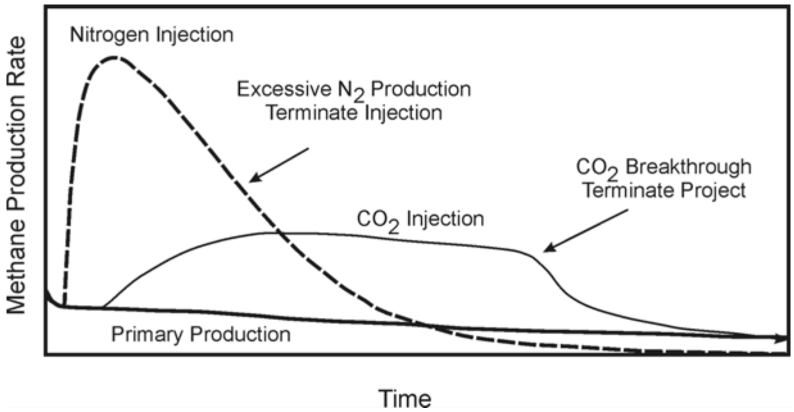
Underground storage of greenhouse gases (GHG) is one of several possible methods to reduce CO_2 venting to the atmosphere. Possible sites include coal beds, depleted oil and gas reservoirs, abandoned and sealed mines, salt domes, aquifers, and within natural minerals. Coal seams provide one of the most attractive sites due to the huge coal resources around the world and the fact that carbon dioxide (CO_2) sorption into coal is high. The sorptive capacity of CO_2 ranges from 1.8 times the sorptive capacity of methane for high rank bituminous coals to up to 10 times for the low rank sub-bituminous coals. Generally, gas sorption capacity decreases as temperature increases. The relative sorptive capacity of CO_2 in coal has the added advantage that injection of CO_2 into coal will displace methane. The cost of CO_2 sequestration can be offset if the methane can be captured and sold. Using the captured methane to displace coal for electricity generation can significantly reduce GHG emissions.

The CO_2 sequestration/enhanced recovery process (ECBM) works by replacing sorbed methane (CH_4) molecules in the micro-porosity with sorbed CO_2 molecules. The CH_4 molecules are displaced into the coal fractures and to producing wells. The CO_2 is trapped in the micro porosity and there is little breakthrough to production wells until the majority of the well pattern is swept. A sequestration project terminates at breakthrough. This technology is currently only being tested at the pilot scale in North America.

N_2 can also be used to enhance coalbed methane (CBM) production by injection. N_2 injection rapidly increases the methane production rate. The timing and magnitude depends upon the distance between injection and production wells, the natural fracture porosity and permeability, and the sorption properties. N_2 breakthrough at the production well occurs rapidly. The N_2 content of the produced gas continues to increase until it becomes excessive, i.e., 50% or greater, at the point illustrated in **Figure E.1.**

The production increase due to CO_2 injection takes longer to develop. This is due to sorption of CO_2 relatively near the well with the sorbed CO_2-methane front growing elliptically out from the injection wells. After a sufficient volume of methane has been displaced, the methane productivity increases. Eventually, CO_2 will breakthrough to the production well when sufficient CO_2 has been injected. At breakthrough, there are few hydrocarbons left in the reservoir and the project is terminated.

Figure E.1. Example N_2 or CO_2 ECBM Pilot Prediction



In the absence of government incentives, the sequestration/enhanced recovery process must be commercially attractive to interest investors in the large investments required for well facilities and flue gas collection systems. An initial observation, under the current economic regime, is that CO_2 is normally too expensive a push gas to use in ECBM because at least 2 molecules of CO_2 remain behind in the CBM reservoir for every molecule of methane produced. However, in special situations where gas supply is low (i.e. gas prices are high) and CO_2 prices are low (i.e. a pure CO_2 waste stream exists as a consequence of an industrial process) the economics could be favorable. In the future, if storage of CO_2 waste has value, then CO_2-ECBM may become an important strategy for reduction of GHGs.

A combination of N_2 and CO_2 injection may be required to maximize sequestration, enhanced recovery volume, and project monetary return. The source of the injected gases will be flue gas emissions or gas treating plant byproducts.

Although ECBM technology is being developed in North America, in the future it would have the greatest potential in countries where coal is abundant but the conventional natural gas supply is not. In order to move this technology towards wider acceptance, especially as a CO_2 sequestration measure, it is important that there should be successful CO_2 sequestration demonstrations. The IEA Greenhouse Gas R&D Programme (IEA GHG) has chosen China, India, Poland and Australia as targets to promote for demonstration of CO_2-ECBM. This study represents a first step in that direction by estimating the CO_2 sequestration potential of coal basins from available detailed geological and reservoir appraisals of basins in Australia, China, Poland and India; selecting preferred areas; and recommendation, design and costing of a CO_2 sequestration demonstration pilot.

Basin Study

In a "topdown" analysis, geological assessment of the four countries identified 8 "best" prospective basins for CBM development. They are:

India:	Damodar Valley
	Cambay Basin
Poland:	Upper Silesian Basin
China:	Ordos Basin
	Qinshui Basin

Australia: Bowen Basin
Sydney Basin
Gunnedah Basin

Other basins were considered but eliminated due to poor CBM/CO_2 sequestration potential or lack of sufficient CBM information.

Even for these 8 basins, the amount of detailed information varied widely for the basins. Also, data from selected sites in a particular basin indicate that the CBM properties between sites can be quite different. It is difficult to "average" these properties on a basin scale. In the case of the Damodar Valley and Cambay Basin in India, there is insufficient reservoir data available to consider it for a sequestration demonstration site. In the Upper Silesian Basin in Poland and in the Sydney Basin in Australia, land-use competition could delay or stop approval of a sequestration site. The Gunnedah Basin in Australia is not as well characterized as the Bowen Basin. The fact that the Bowen Basin in Australia has commercial production exceeding 28.5 million cubic meters (1 Bcf) annually whereas the three other countries have no commercial production is the reason for ranking the Bowen Basin over the Ordos and Qinshui Basins in China as the best basin to evaluate for a demonstration site. This ranking may not stand in the future as more data become available. In order to be as impartial as possible, it was decided to independently rank the basins from the "bottom up" by ranking individual sites in each basin instead of relying completely on this top down analysis.

Site Selection

Geological assessment of the four countries identified eleven potential sites for locating the CO_2-enhanced coalbed methane (ECBM) pilot. They are:

India:	Damodar Basin - Jharia Coalfield in the Parbatpur Block
	Cambay Basin, Gujarat, in the Mehsana Block
Poland:	Upper Silesian Basin - former Amoco Block, south of town of Tychy
China:	Eastern Ordos Basin
	Southern Qinshui Basin – Jincheng field
Australia:	Southern Bowen Basin - Dawson River, Moura, Fairview and Durham Ranch
	Southern Sydney Basin - Camden
	Gunnedah Basin - Narrabri

Ranking of Sites

Each site was evaluated on the following five factors:

- Market Potential
- Production Potential
- CBM Resource/CO_2 Storage Potential
- CO_2 Supply Potential
- Site Infrastructure Costs (Financeability)

A scoring system was proposed to score each factor. The score for each factor was calculated from the sum of its components and then normalized to 1. This scoring method used an additive approach to calculate each factor score followed by a multiplicative approach to calculate the site score. These five factors can be illustrated in a pentagon. The top of the pentagon is market potential, which is the economic driver of the project. The two corners at the base of the pentagon are CBM resource/CO_2 storage potential and CO_2 supply potential. These are the resource bases where production and site infrastructure can be built-up on to fulfill the market needs. The line from the center to the corner of the pentagon represents a score of 1 (full score) for each of the five factors. Hence, the scores can be visually presented and compared between two sites.

Finally an "uncertainty factor" was estimated which would discount the site score to reflect uncertainties in the estimates. This approach better captures the essence of the evaluation issues, as all five factors are inter-related and essential to the success of the project. Presently we use drilling density around the site as a proxy for the uncertainty factor to calculate an "adjusted site score". As more data become available, we can use more sophisticated technique such as Monte Carlo simulation to assess uncertainties in the estimate.

The scoring system is first applied to select the best site from each country, and then they are used to rank the country. The scoring of the best site from each country are summarized below:

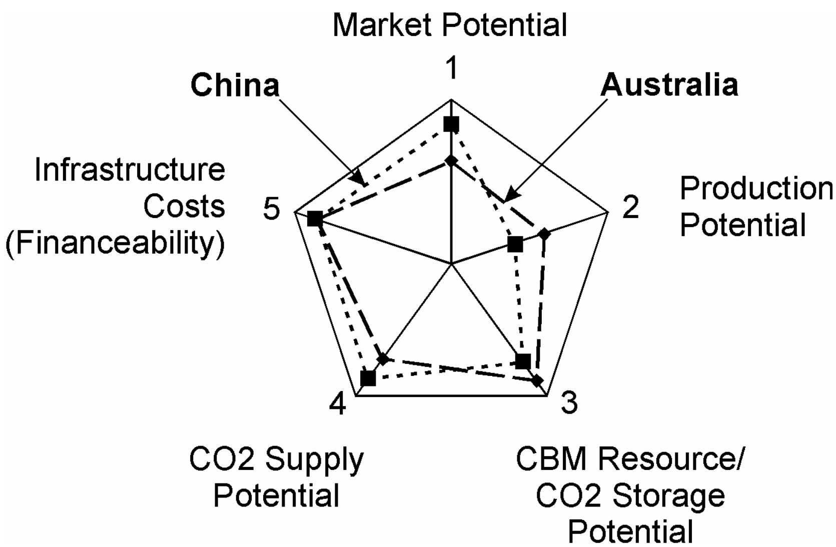
	Australia **South Bowen, Dawson River**	***China*** **South Qinshui, Jincheng Field**	***Poland*** **Upper Silesian, Former Amoco Site**	***India*** **Cambay Gujarat, Mehsana Block**
Market Potential	0.62	0.85	0.85	0.69
Production Potential	0.60	0.40	0.40	0.60
CBM Resource/ CO_2 Storage Potential	0.88	0.75	0.50	0.75
CO_2 Supply Potential	0.71	0.86	0.86	0.86
Site Infrastructure Costs	0.86	0.86	0.71	0.43
Site Score	198	186	104	114
Uncertainty Factor	1.0	0.9	0.7	0.5
Adjusted Site Score	198	168	73	57

Australia has the highest score followed by China, Poland and India. The India score is low because of a lower gas market potential, as the gas market infrastructure is not well developed and a lower infrastructure cost rating (financeability). In addition, the Cambay Basin is the least explored basin for CBM among the four basins, hence the high uncertainty factor. Poland also scores quite well, but it is hindered by a low production potential and low CBM resource potential. One of the reasons for that is because site information is lacking and we have to rely on basin average data for evaluation.

Comparing China and Australia, the strengths of the China site are its high gas demand potential and CO_2 supply potential, while the site infrastructure costs (financeability) are comparable. The strengths of the Australia site are its production potential and CBM resource potential. This can be illustrated in the pentagon, as shown in **Figure E.2**. In other words, the Australia site offers the best potential for technical performance while the China site is the best site where the technology is most needed.

In summary, we rank the four countries in descending order as Australia, China, Poland and India. The scores of the Australia and China sites are very close. In additional to the technical performance and market potential considerations, there is the developed and developing country perspective, which would impact on the potential funding sources. Both sites have merits and should be further evaluated for pilot plant design and economic assessment.

Figure E.2 Comparing the Australia and China Sites



Technical Design of the Demonstration Pilot

To ensure that the process can be implemented successfully from both a technical and economic viewpoint, a staged process must be used. We proposed a three-stage process – micro-pilot testing followed by 5-spot pilot testing and 9-pattern testing as shown in Table E.1. This design would be suitable for both the Australia and the China sites.

Table E.1 Major Pilot Stages

Stage	Description	Number of Wells
1	Micro-Pilot Testing	1 Injection/Production
2	5-Spot Pilot Testing	4 Injection/1 Production
3	9-Pattern Testing	16 Injection/25 Production

Stage 1: Micro-Pilot Testing

The micro-pilot involves costs related to field review, well drilling and evaluation, micro-pilot testing, data analysis and 5-spot pilot design. In the micro-pilot test, approximately 200 tonnes of CO_2 are injected over a week into one well. The CO_2 will be trucked to the project site for injection. After a soak period, the well is produced while monitoring flow rates, pressure and gas composition.

Stage 2: 5-Spot Pilot Testing

The 5-spot pilot involves drilling four additional wells (one producer and three injection wells), converting the micro-pilot well to an injector, construction of a surface facility, injection of CO_2 and flue gas, production testing, data analysis and project design. In the full field pilot, approximately 15,000 tonnes of CO_2 (or flue gas) are injected over six months. The CO_2 (or flue gas) will be generated by exhaust from a propane-fueled compressor supplemented by trucked CO_2, prior to injection. The injection/production operation will run continuously for at least 6 months. The entire stage will require roughly two years to complete

Stage 3: 9-Pattern Testing

It should be clear from the 5-spot pilot test whether a larger scale effort is warranted. If so, an additional eight patterns can be installed surrounding the 5-spot pilot. The ability to expand hinges on the availability to deliver injection fluids (CO_2 or flue gas) to the site without excessive transportation and compression costs. The proposed 41- well commercial demonstration is injecting 400 tonnes CO_2 per day or 120,000 tonnes CO_2 per year. At the 9-pattern piloting stage the injection gas is from the exhaust stream from a gas plant, a slipstream from a coal-fired power plant or some other large source is utilized. It is difficult to estimate the cost of the 9-pattern commercial demonstration at this time, because we do not have the 5-spot pilot reservoir performance data. The injection rate, injection pressure, source of CO_2, produced well stream production rate, gas composition etc. would greatly impact on the surface facility design and cost. From the operation perspective, the sales of the methane gas can probably offset some of the operating costs.

In order to implement the ECBM project, we have considered the following specific issues:

- Secured CO_2 supply, which is critical to the success of the ECBM process;
- Government policy on CO_2 reduction credit, whereby a value for the CO_2 sequestered can be created;
- Regulatory issues including the verification and validation of the CO_2 credit (this would necessitate some form of CO_2 monitoring), land ownership, safety and health issues; and
- Financing sources

Project funding is an important issue. With China being a developing country, the demonstration pilot would likely be developed as a technology transfer project in the beginning with the potential of developing it into a clean development mechanism project or commercial venture in the longer term. The recipient of the technology in the host country would be represented by the state owned company, which for the case of China would be China United Coalbed Methane Co. Ltd. (CUCBM). CUCBM is charged by the State Council for all exploration, development, production and sales of coalbed methane in China. As often the case, the state owned company would not have any hard currency to contribute, but is expected to provide in kind services such as obtaining permit approval, geological assessment, field manpower, well services and local supplies. For Stage 1 and perhaps Stage 2 of the demonstration pilot, the hard currency financing could come from International Development Agencies such as the World Bank Global Environmental Facility (GEF), United Nations Development Program (UNDP), Regional Bank such as Asia Development

Bank (ADB) or Bilateral Granting Agencies such as US Agency for International Development (USAID) for the case of the US and Canadian International Development Agency (CIDA) for the case of Canada. To get approval for International or Bilateral Grants, blessings from the Government such as the State Council and the Ministry of Foreign Trade and Economic Co-operation (MOFTEC) are essential. When the project goes to Stage 3 - commercial demonstration, either CUCBM can provide the financial resources or other international oil and gas companies can be brought in to provide financing to earn a share of the commercial revenues. This process is quite typical of financing project in a developing country.

Since Australia is an advanced industrialized nation, some of the grant funding and loan sources such as World Bank's GEF, International Finance Corporation, or Bilateral Development Agencies such as USAID, CIDA, which would normally be available to developing countries, would not be available to Australia. We expect that private and Australia Government funding will probably be the route. Fortunately, since the pilot demonstration project is developed in stages, it could provide the time to develop these funding sources gradually. Initially, we envision that Stage 1 of the demonstration project will be funded mostly with Government grant funding supplemented with some industrial funding. Gradually, as the project proceeds through the stages, major energy companies such as Oil Company of Australia or BHP Petroleum Pty Ltd. who would benefit most from the commercialization of the process will emerge as the "Champion" and take an increasing share of project financing.

Demonstration Pilot Plant Costs

Table E.2 is a summary of the three stages of the demonstration pilot plant cost estimates for the Dawson River site, south Bowen Basin in Australia and the south Qinshui Basin site in China.

Table E.2 Comparison of Demonstration Pilot Plant Costs for the Australia Site and China Site

$ US Million	**Australia Site, South Bowen Basin**	**China Site, South Qinshui Basin**
Stage 1: Micro-Pilot Testing	0.67	0.73
Stage 2: 5-Spot Piloting Testing (net cost is after 50% cost recovery of compressor and flue gas generator)	6.2 (net 4.8)	6.7 (net 5.3)
Stage 3: 9 Patterns 5-Spot Testing	35	40

The accuracy of the cost estimate for Stage 1 Micro-Pilot Testing and Stage 2 5-Spot Pilot Testing is expected to be in the +/- 30% range. The uncertainty item in Stage 2 is the cost of the CO_2/flue gas generator, which is a relatively new technology. The Stage 3 costs would be considerably less accurate as we do not have the 5-spot pilot reservoir performance data.

Comparison of the cost estimates suggests that the demonstration pilot plant costs for the China site (for all three stages) are generally10% higher than the Australia site. While surface facility and testing costs are roughly the same, drilling and completion costs are about 30% higher in China. The difference can be explained by the general accessibility of drilling rigs and the costs of well drilling and completion services for the two sites and the fact that for the Australia site, we can take advantage of mineral rigs that are available in the south Bowen Basin rather than using conventional oil rigs, which is the case for the China site. The Qinshui Basin is not as accessible as the Bowen Basin. However, as more service company competition or large-scale projects are being implemented in the Qinshui Basin, this would lower the drilling and completion costs.

Liquid CO_2 supply for the micro-pilot testing does not appear to be a problem, as both sites are accessible to tanker trucks and pumping equipment. However, the costs of delivering the CO_2 to site can be highly variable, as transportation costs could be substantial, depending on the location of the liquid CO_2 supply source.

Economic Analysis

The Australian - Dawson River site is located to the south of the Dawson Valley field in the southeast district of the Bowen Basin. Lease PL 94 occupies an area of 242 km^2. Gas in place is estimated at 58 Gm^3 (2 Tcf). Resource concentration is 240 Mm^3/km^2. Our economic analysis assumes an ECBM project, which encompasses 65 km^2 (16,000 acres) or approximately 27% of the prospective lease.

The Chinese - Jincheng site is located approximately 1,000 km to the south and east of Beijing, in the southeast district of the Qinshui Basin. The Jingcheng area occupies an area of 406 km^2 (40,600 ha). Gas in place is estimated at 99 Gm^3 (3.5 Tcf). Resource concentration is 244 Mm^3/km^2. Our economic analysis assumes an ECBM project, which encompasses 65 km^2 or approximately 16% of the prospective area. It is a small portion, approximately 7% of the total area of the Qinshui Basin (5,560 km^2).

Initially ECBM projects will likely occur at the conventional CBM project sites, due to the presence of an existing infrastructure, which greatly reduces the investment risk. Therefore, our economic analysis assumes that land permits, micro-pilot and 5-spot pilot testing has been completed for the hypothetical ECBM project site. The commercial project is projected to require 50 CBM producing wells initially with further 50 wells drilled in subsequent years with spacing of 65 hectares (160 acres). A total of 64 injections are also drilled as a component of the ECBM evaluation.

We have made assumptions on the reservoir parameters and production forecasts and developed a simple model based on the local geology, engineering practice and operations. We evaluated three cases – primary production, ECBM with CO_2 injection and ECBM with flue gas (80% CO_2, 20% N_2) injection.

A significant cost of an ECBM project will be in the capture, purification, compression and transportation of the CO_2 from the coal-fired generation plant to the project site. The CO_2 supply cost is dependent on the CO_2 concentration in the flue stack, capture/separation process selected, compression requirements and distance to the ECBM project site. Therefore, for easier interpretation, our economic analysis assumes a high quality CO_2 at pipeline pressure (1,200 psig or 8.27 MPa) would be available at the project site at zero cost. Our analysis compares the economic costs/benefits of ECBM projects versus conventional CBM projects in the Bowen Basin, at various constant plant-gate gas prices. These results were then used to determine an affordable CO_2 cost/credit for ECBM projects so that it can compete with conventional CBM projects.

The economic analysis for the Australia Project and China Project suggests that the ECBM process can recover substantial incremental methane at a cost comparable to primary production, provided that the CO_2 or flue gas can be delivered to the field site at an "affordable price". It is found that the affordable price for the injection gas ranges from less than $ US 0 to $ US 12/tonne CO_2, for a range of plant-gate methane gas prices from $ US 0.50 to $ 3.00/GJ. This is far lower than the cost required to capture/separate, compress and transport the CO_2 or flue gas to the field, which is estimated at $ US 25 – 35/tonne CO_2 of recovering CO_2 from coal-fired power plant flue gas using current amine separation technology. For this process to be economically viable the cost of CO_2 capture must be lowered or there is a credit for CO_2 sequestered.

Cost Assumptions for the hypothetical commercial ECBM project in Australia and China

- Drilling and completion costs are about 30% higher for the China project than the Australia project
- Surface facility costs are roughly the same
- Operating Costs are the same
- Fiscal Regime seems more favorable in China than Australia
  - Royalty and VAT 5% versus 10%
  - Depreciation over 8 years versus 15 years
  - 33% income tax rate versus 36%

Comparative Economics

Table E.3 is a summary of breakeven gas prices in $ US /GJ, to achieve a 10% return, after income tax for the Australia project and China project.

Table E.3 Breakeven gas Price for the Australia Project and China Project

$ US /GJ	**Australia Project, South Bowen Basin**	**China Project, South Qinshui Basin**
Conventional CBM	1.10	1.25
ECBM (CO_2)	1.00	1.05
ECBM (Flue Gas)	0.90	0.90

- For Conventional CBM, the breakeven gas price in China is higher ($ US 1.25 versus $ US 1.10/GJ), because of the higher capital costs with respect to drilling and completion costs.
- For CO_2 and flue gas ECBM projects, the China economics are improving at a more rapid rate than Australia. This is due to the effect of a better financial and fiscal regime in terms of a lower royalty rate, lower income tax rate and more rapid depreciation. For the flue gas ECBM project, the economics between China and Australia are equal. This suggests that the fiscal regime for China is more favorable to incremental production economics such as the enhanced recovery of CBM.

Affordable Price for CO_2 and Flue Gas and net CO_2 Sequestered

Table E.4 is a summary of affordable prices of CO_2 and flue gas for the Australia and China projects at a gas price of $ US 1.50/GJ.

Table E.4 Affordable Price for CO_2 and Flue Gas at $ US 1.50/GJ Gas Price

	Australia Project, South Bowen Basin	**China Project, South Qinshui Basin**
Affordable Price @ $ US 1.50/GJ		
CO_2	$ US 2.35/t	$ US 3.00/t
Flue Gas	$ US 3.80/t	$ US 5.00/t

Affordable price of CO_2 is the maximum price that the CO_2-ECBM project can afford to pay for the CO_2 while attaining the same net present value as the conventional CBM project. At the higher gas prices, the affordable price for CO_2 and flue gas will be higher. Under the same gas price, the China project produces higher affordable price for the CO_2 and flue gas than the Australia project because of a more favorable financial and fiscal regime.

Net CO_2 Sequestered

One possibility of an additional revenue stream for the CO_2-ECBM process is through the creation of CO_2 credits. CO_2 not released to the atmosphere should be allowed to earn credits towards the country's CO_2 reduction target under the Kyoto Protocol. This would create a value for the CO_2 sequestered in the coalbeds. Currently, there is no Government policy in place to do this. However, many countries including the U.S., Canada and Australia are considering this option.

For the credit system to work, we must introduce the concept of CO_2 avoided or net CO_2 sequestered. In the sequestration case, energy used for capture and compression generates additional CO_2 emissions, which is precisely what we want to avoid. The process of recovering the ECBM injection volumes (CO_2 or flue gas) from coal-fired generation or other industrial sources requires a source of energy that also results in CO_2 emissions. The process of compressing the ECBM injection volumes for transmission to the project site will also create CO_2 emissions. These CO_2 emissions generated in the process of providing an ECBM injection volume to the project site must be deducted from the CO_2 volumes sequestered to calculate the net CO_2 sequestered.

The total volume of the CO_2 injected during the life of the hypothetical commercial CO_2-ECBM project in Australia and China will be 15.3 $10^9 m^3$ (about 28.6 million tonnes). To calculate the CO_2 avoided or net CO_2 sequestered requires some engineering details, as it is process dependent and fuel dependent. Using the example from the literature, which calculates that net sequestered CO_2 volume is approximately 65 percent of the injected CO_2 volumes, our hypothetical development in the Bowen Basin has provided a net CO_2 sequestering of approximately 20.5 million tonnes for the ECBM (CO_2) project and 16.4 million tonnes for the ECBM (flue gas) project.

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- Joseph Cooper of Joseph Cooper Consultant, Houston, Texas, U.S.A. for the geological assessment of the India basins.
- Matt Mavor of Tesseract Corporation, Park City, Utah, U.S.A. for the technical design of the demonstrations pilot.

We are indeed fortunate to have them involved to add to the breath of this study.

CHAPTER 1
OVERVIEW OF THE STUDY

1.1 Introduction

The "Greenhouse Effect" is the gradual warming of the earth's surface due to increased entrapment of solar radiation in the atmosphere. Since the 1950's, it has been suspected that small increases in "greenhouse gases" in the atmosphere have been causing a general increase in the mean annual surface temperature of the earth, which is about 15^{o}C. Scientists estimate that an increase of 0.25^{o}C has resulted between 1880 and 1940 (Halman and Steinberg, 1999). While the increase in the average temperature does not seem significant, the temperature increase in desert and frozen regions is believed to be much greater and may have a profound effect upon vegetation and sea levels in the future.

The most important greenhouse gases are water vapor (H_2O), carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), tropospheric ozone (O_3), and man-made chlorofluorocarbons ($CFCl_3$ and CF_2Cl_2). The relative contribution of these gases to the greenhouse effect is summarized in Table 1.1 (Hitchon, 1996). CO_2 is by far the most significant contributor. The CO_2 source is emissions from fossil-fuel combustion and cement production. Coal combustion for electricity generation is the primary combustion source as it is the largest source of energy from the earth. Coal also generates more CO_2 per unit of energy content than crude oil or natural gas. Reduction of CO_2 emissions into the atmosphere from fossil fuel and especially coal combustion should reduce the release of CO_2 into the atmosphere.

Table 1.1 Relative Contribution to Greenhouse Effects of Various Gases

Gas	% Greenhouse Effect
CO_2	63.6
CH_4	19.2
N_2O	5.7
CFCs and others	11.5
Total	100.0

Nations are evaluating technologies for large-scale reductions of greenhouse gas (GHG) emissions to reduce the rate of global warming. These technologies fall in three general areas (Gunter et al., 1998): (1) "Energy Intensity Reduction" by efficiency or conservation leading to lower consumption of fossil fuels, (2) "Carbon Intensity Reduction" by fuel switching, and (3) "Carbon Management" where CO_2 is captured and stored in biomass or geological formations. A mix of these three strategies is necessary to meet the reductions targeted by the Kyoto Protocol.

Natural gas is a cleaner burning fuel than coal and it emits approximately half the CO_2 emissions per unit energy that coal does. Replacing coal by natural gas in new power plants is one strategy being planned by industry to reduce GHG emissions. This is only possible if an ample supply of natural gas is available. The supply of conventional natural gas is declining. Consequently, improved technologies must be developed for exploiting the unconventional gas resource. Coalbed methane (CBM) is one of these targets. Technology for recovering coalbed methane was largely developed in the US in the 1970's spurred on by a tax incentive. Until recently, the US was the only country in the world with commercial production. The current U.S. production exceeds 1 trillion cubic feet (Tcf) (29 Bm^3) year and is growing. Australia is the second country to have commercial production from deep unmined coals but the production is very small compared to the U.S. production. China will probably be the third country to attain commercial production.

Underground storage of greenhouse gases (geosphere sinks) is one of several possible methods to reduce venting to the atmosphere. The other methods are material sinks (for example, storing the CO_2 in wood and paper products) and biosphere sinks (storing the CO_2 in deep oceans, forests and agricultural soils). Material sinks will probably only play a minor role as compared to biosphere and geosphere sinks in storage of CO_2. Biosphere sinks are attractive because they can sequester CO_2 from a diffuse source whereas geosphere sinks require a pure stream of CO_2 (obtained by using expensive separation methods). On the other hand, environmental factors and storage time favor geosphere sinks (Gunter et al., 1998). Possible geosphere sinks include coalbeds, depleted oil and gas reservoirs, abandoned and sealed mines, salt domes, aquifers, and within natural minerals (Hitchon et al. 1999). Coal seams provide one of the most attractive sites due to the huge coal resources around the world and the fact that CO_2 sorption into coal is high, ranging between 1.8 (Yee and Seidle, 1993) and 10 (Mavor et al., 1999) times the sorptive capacity of methane. The higher sorption capacity was observed in low rank coals. Pratt et al.(1999) reported that CO_2 storage capacities are as much as 8.5 to 9.8 times greater than methane storage capacities for the Powder River Basin sub-bituminous coal. Whether this phenomena is typical or a rare occurrence is still waiting to be verified, as coal gas reservoir data for subbituminous coal are scarce. It is often presumed that there is a regular relationship between high rank coal and high gas content. However, the observation of high sorption capacity in low rank coals will render a case that low rank coal reservoirs could still be considered sites for CO_2 storage, despite the low gas content. The relative sorptive capacity of CO_2 in coal has the added advantage that injection of CO_2 into coal will displace methane. The cost of CO_2 sequestration can be offset if the methane can be captured and sold. Using the captured methane to displace coal for electricity generation can significantly reduce greenhouse gas emissions.

To understand integrated CO_2 sequestration/CBM production processes, it is important to understand that coal gas reservoirs are dual storage reservoirs consisting of primary and secondary storage systems. The primary storage system makes up 98% or greater of the reservoir volume and contains organic matter, inorganic material, inherent water, and gas stored within very small pore spaces. Primary system gas storage is dominated by the sorption phenomena because of the small size of the pores. During sorption, the gas molecules are within very close proximity to solid surfaces, are attracted to the solid and are packed closer together than expected from the pressure conditions, forming a dense phase. The intensity of adsorption depends on temperature, pressure, coal rank and gas type. Methane is the most dominant gas trapped naturally in coals, exceeding 90% in most cases. Carbon dioxide, which is normally a minor constituent, adsorbs twice to ten times as strongly as methane. Nitrogen (N_2), another minor constituent, only adsorbs one half as strongly as methane. The primary porosity system is relatively impermeable and mass transfer is dominated by diffusion (driven by gas concentration gradients). Commercially productive coal gas reservoirs contain a well-developed secondary storage system dominated by natural fractures. Without natural fractures, commercial production would not be possible. Flow through the secondary storage system is due to pressure gradients between the fracture system and production wells. The majority of gas in a coal gas reservoir diffuses through the primary storage system, desorbs at the interface between the primary and secondary systems, and then flows through the secondary system to wells (Mavor, 1996).

1.2 CO_2 & N_2 Enhanced Coalbed Methane Production Technology

Either CO_2 or N_2 can be used to enhance CBM production (ECBM) by injection. The injected gas increases the pressure in the reservoir and adsorbs onto the coal displacing the methane and driving it to the production well by flow through natural cleats in the coal.

The CO_2 sequestration/enhanced recovery process works by replacing sorbed CH_4 molecules in the primary porosity with sorbed CO_2 molecules. The CH_4 molecules are displaced into the secondary porosity and to producing wells. The CO_2 is trapped in the primary porosity and there is little breakthrough to production wells until the majority of the well pattern is swept. A sequestration project terminates at breakthrough. This technology is currently only being tested at the pilot scale in North America.

The mechanism of CO_2 sequestration/ECBM production is based upon the relative sorptive capacity of CO_2 and CH_4. Lower rank coals, often found at shallow depths, such as the subbituminous C coal of the Fort Union Formation of the Powder River Basin, Wyoming, have a great affinity for CO_2, ten times that of methane. While this low rank coal may be excellent for sequestration in the right reservoir setting (i.e., depth and pressure), the ECBM process will not be effective. Injection of ten volumes of CO_2 will displace only one volume of methane. As a result, the cost of injecting CO_2 cannot be significantly reduced by the sale of methane. However, in high volatile B and A bituminous coals, (such as those found in the Uinta Basin and the Fruitland Formation coal gas reservoirs of the San Juan Basin in Colorado and New Mexico) injection of two volumes of CO_2 will displace roughly one volume of methane. The increase in the ratio of methane released to CO_2 injected has a good chance in providing significant reduction in the cost of CO_2 sequestration.

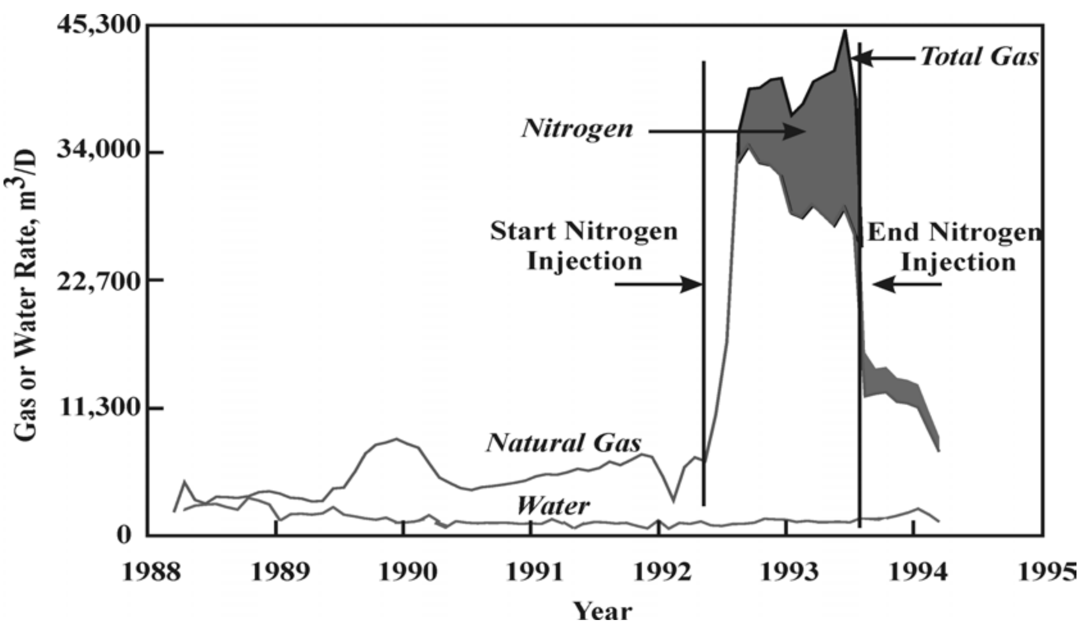
Burlington Resources Inc. was excited about the promise of enhanced recovery and performed a CO_2 sequestration/ECBM pilot in Fruitland coal seams in New Mexico in an area they refer to as the Allison Unit. The pilot consisted of four CO_2 injection wells drilled between production wells. They injected 98% CO_2 and 2% N_2 for a period of roughly three years at a total rate between 105,000 and 181,000 m^3/d (3,700 and 6,400 Mcfd). The source of the gas was a 2,000 psig (13.8 MPa) CO_2 transmission pipeline located roughly 50 km (30 miles) from the pilot that ships CO_2 to Texas enhanced oil recovery projects (Stevens et al., 1998).

The Burlington pilot was the world's first production pilot. The pilot was run in the middle of a number of production changes. This made it difficult to isolate the enhancement effects of CO_2. During the injection, they worked over production wells by repeating open-hole cavity completions. The resulting production increase might be due to the workovers and not due to the injection of CO_2. The effort described in this document will hopefully learn from this experiment to ensure that the effects of CO_2 and N_2 injection are properly understood.

One important aspect of the Burlington pilot was that there was little breakthrough of CO_2 to producing wells. The average concentration of CO_2 in the produced gas stream from four wells closest to the injection wells changed by less than 0.5%. One well increased by 2%. This was the result expected from theory due to the stronger sorptive capacity of CO_2 relative to methane supporting the sequestration potential of coal. As expected, N_2 broke through roughly 3 months after injection due to its lower sorptive capacity relative to methane.

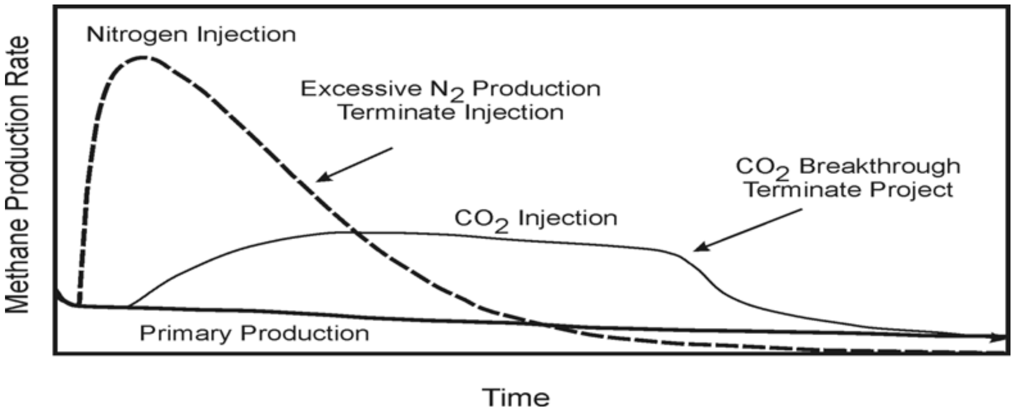
BP-Amoco has been successful at improving hydrocarbon gas recovery with N_2 injection. **Figure 1.1** illustrates the total and methane gas production rates before and after N_2 injection at their Fruitland coal Simon pilot site in the northwestern portion of the San Juan Basin in Colorado. Injection of N_2 rapidly improved the hydrocarbon gas production rate by a factor of five. The N_2 enhanced recovery mechanism is different from that for CO_2. N_2 is less sorptive than methane: N_2 sorptive capacity is roughly 40% that of methane for a high volatile A bituminous coal. The N_2 process works by reducing the partial pressure of methane in the secondary system, increasing the rate of desorption from the primary porosity system and the rate of methane diffusion through the primary porosity. Some N_2 enters the coal matrix. N_2 also increases the coal natural fracture system total pressure, maintaining the stress-sensitive coal permeability and increasing the driving force to push gas through the fracture system to producing wells. One significant difference between N_2 and CO_2 injection is that the N_2 breaks through to the production wells and dilutes the well stream. When N_2 production becomes excessive, the production stream must be processed to reject N_2. Rejection is usually accomplished with a cryogenic process.

Figure 1.1 BP-Amoco Simon N_2 Injection Pilot Performance.



Coal gas reservoir simulation technology is required to predict reservoir behavior and injection-production performance. **Figure 1.2** illustrates examples of simulation computations. This figure schematically illustrates the methane recovery rate for two enhanced recovery scenarios, the first due to injection of pure N_2, and the second due to injection of pure CO_2, as well as the expected recovery without injection (i.e. primary production).

Figure 1.2. Examples of N_2 and CO_2 ECBM Pilot Prediction.



N_2 injection rapidly increases the methane production rate. The timing and magnitude depends upon the distance between injection and production wells, the natural fracture porosity and permeability, and the sorption properties. N_2 breakthrough at the production well occurs at about half the time required to reach the maximum methane production rate. The N_2 content of the produced gas continues to increase until it becomes excessive, i.e., 50% or greater at the point illustrated in **Figure 1.2**. The production increase due to CO_2 injection takes longer to develop. This is due to sorption of CO_2 relatively near the well with the sorbed CO_2-methane front growing elliptically out from the injection wells. After a sufficient volume of methane has been displaced (roughly 20% of the reservoir volume), the methane productivity increases. Eventually, CO_2 will breakthrough to the production well when sufficient CO_2 has been injected. At breakthrough, there are few hydrocarbons left in the reservoir and the project is terminated.

In the absence of government incentives, the sequestration/enhanced recovery process must be commercially attractive to interest investors in the large investments required for well facilities and flue gas collection systems. An initial observation, under the current economic regime, is that CO_2 is normally too expensive a push gas to use in ECBM because at least 2 molecules of CO_2 remain behind in the CBM reservoir for every molecule of methane produced. However, in special situations where gas supply is low (i.e. gas prices are high) and CO_2 prices are low (i.e. a pure CO_2 waste stream exists as a consequence of an industrial process) the economics could be favorable. In the future, if storage of CO_2 waste has value, then CO_2-ECBM may become an important strategy for reduction of GHGs. One could visualize coal-fired power plants, where the CO_2 is captured from flue gas and injected into deep coal beds to release the CBM which could be used for power or other purposes (Gunter et al., 1997).

A combination of N_2 and CO_2 injection may be required to maximize sequestration, enhance recovery volume and project monetary returns. The source of the injected gases will be flue gas emissions or gas treating plant byproducts.

1.3 CO_2 Capture, Processing, Transport and Injection

The cost of disposing of CO_2 in CBM reservoirs is made up of four factors: capture (i.e. capture/separation of CO_2 from other combustion gases), compression, pipelining and injection (pumping and CBM wells). The largest CO_2 sources are coal-fired power plants. Current technology used for capturing CO_2 from flue gas is using amine absorption at a cost of Cdn \$30 to 50/t CO_2 (US \$20 to 33.3/t). After purification, the CO_2 is compressed, typically to 2000 psi (13,800 kPa) for pipeline delivery. It requires multistage compression with cooling between stages. Typically compression costs range from Cdn \$8 to 10/t CO_2 (US \$ 5.3 to 6.7/t). Pipelining CO_2 is a well established commercial technology. The pipeline can be laid using normal pipeline construction methods. Pipelining costs range from Cdn \$0.7 to \$4/t CO_2/100 km (US \$ 0.47 to 2.67/tCO_2/100 km), depending on construction terrain. Potential problems are pipeline corrosion and gas-liquid two phase flow. Injection of compressed CO_2 into coalbed methane reservoirs on land can be carried out with conventional drilling and well technologies. Pumping of CO_2 liquid is relatively inexpensive. Cost for CO_2 injection will vary with well cost and reservoir injectivity. Typical cost ranges from Cdn \$2 to \$8/t CO_2 (US \$ 1.3 to 5.3/t). Capture/separation costs represent the largest financial impediment to the process (Wong et al., 1999, Wong et al., 2000a).

Flue gas injection may enhance the process economics to the point that large-scale commercial application is possible. Considering both production economic and CO_2 sequestration factors, there might be an advantage to optimizing the CO_2/N_2 composition of the flue gas. Work completed by the Alberta Research Council, suggests that costs may be lowered by injecting an impure stream of CO_2 because the capture/separation costs are substantially lowered. The CO_2 will remain adsorbed in the coal while the majority of the N_2 will be produced along with the hydrocarbon gases which may be sold for profit. Technical issues that need to be addressed are the flue gas conditioning, compression, delivery and net CO_2 sequestered (Wong et al., 2000b).

Compared to pure CO_2, flue gas injection requires a higher amount of compression for injecting the same unit of gas downhole. One important component of the process design will be to select efficient compressors that minimize the volume of CO_2 created relative to the CO_2 injected. This design must also incorporate the economics on pre-treating the flue gas and extracting the nitrogen from produced methane.

The process of flue gas injection can be summarized as follows:

1. Collect dirty flue gas that contains N_2, CO_2, O_2, NO_2, SO_2 and other pollutants.
2. Collect and process the flue gas to remove particulate solid material and water and to enrich the gas in CO_2.
3. Compress the flue gas to high pressure, i.e.13,800 kPa(g) (2,000 psig).
4. Inject the flue gas into injection wells completed in coal seams.
5. Produce sweet hydrocarbons, water, and environmentally friendly nitrogen while sequestering carbon dioxide.
6. Strip nitrogen from the produced well stream and sell the hydrocarbons.

The optimum mix of N_2 and CO_2 in the injection gas depends upon the technical and commercial requirements of the process. If sequestration volume is the only consideration, the injected gas should be 100% CO_2. If rapid maximization of hydrocarbon gas recovery is the only consideration, the injected gas should be 100% N_2. The commercial and sequestration compromise will be between these two cases. We expect that the optimum commercial application will involve injecting variable gas composition to control sequestration volumes and the amount of N_2 in the produced gas stream. The range in the N_2 content in the injected gas is likely to be between 25 and 75%.

Typical coal-fired power plant flue gas streams often contain 13% CO_2 with the vast majority of the remainder being N_2. It will be important to combine flue gas CO_2 enrichment technology, underground coal gas behavior technology, and production stream N_2 rejection technology for the optimum process. The pilot project described in this document is designed to collect and evaluate the information required to understand the underground process.

1.4 CO_2 Sequestration – This Study in Relation to Previous IEA Studies

In 1998, Advanced Resources International (ARI) completed a study for the IEA Greenhouse Gas R&D Programme (IEA GHG) which represented the first assessment of the global potential for using CO_2 to enhance CBM recovery, with simultaneous CO_2 sequestration in the coal (IEA GHG, 1998). This study concluded that the injection of carbon dioxide in deep coal seams has the potential to enhance coalbed methane recovery, while simultaneously sequestering carbon dioxide. Analysis of production operations from the world's first carbon dioxide-enhanced coalbed methane production, in the San Juan Basin, indicates that this process is technically and economically feasible. Cost estimates indicate that a typical San Juan basin CO_2-ECBM project would be economic at current wellhead prices for methane of \$0.07/m^3 (\$2.00/Mcf). Projects outside the U.S. could require methane prices of \$0.11/m^3 (\$3.00/Mcf) or more, depending on such considerations as infrastructure development and the existence of oil and gas industry services.

The study concluded that for ECBM to be justified, readily available supplies of low-cost CO_2 are essential, whether derived from natural reservoirs or captured from anthropogenic sources such as power plant flue gas. The presence of efficient and stable long-term markets, the existence of pipeline infrastructure and favorable wellhead prices are all crucial to the economics of ECBM projects. World-wide CO_2 sequestration potential in deep coal seams is estimated to be around 150 Gigatonnes (Gt) of CO_2 based on the 20 coal basins estimated to have the best potential for CO_2-ECBM recovery. Of this total, perhaps 60 Gt of CO_2 may be sequestered at costs of under \$50/t of CO_2.

1.5 Reservoir Screening Criteria

There are three categories that will be considered for the appraisal of the major coal basins – one is quantitative (geologic) which recognizes the size of the deposit and the reserves, the second is technical (reservoir performance) and the third is logistics (access to CO_2 sources and markets). As a reference point, we have summarized this information for Australia, China, India and Poland taken from IEA GHG (1998) in **Table 1.2**. Under the heading "Country", the report's global ranking of CBM potential for each sedimentary basin considered is given. Under the heading "Geological Setting", the total size of the basin in square kilometers, the proportion of the basin which is considered to have CBM potential in square kilometers, the stress regime in the basin, the CBM-bearing formations/age of the formation, the Gas In Place (GIP) in both Giga-cubic-meters (Gm^3) and trillions cubic feet (Tcf), the concentration of CBM in both million cubic meters per square kilometer (Mm^3/km^2) and billions cubic feet per square mile (Bcf/mi^2), the fraction of the CBM which is recoverable in both Gm^3 and Tcf are listed. These data help us to assess the size of the resource. Under the heading "Reservoir Parameters", the range of the individual seam thickness in meters (m), the cumulative seam thickness in meters, the completable cumulative seam thickness/at a depth in meters, the permeability in millidarcies (md), the coal rank, the ash content, the moisture content, gas content in cubic meters per tonne, the saturation state of the gas in the cleats, the extent of cleating and the mineralization are described. These data determine the producibility of the CBM reservoir. Under the heading "Logistics", the gas market, flue gas sources for CO_2, availability of pipelines are considered. These data largely determine the economics of the resource providing that the producibility is satisfactory.

Of the 4 countries and the sedimentary basins identified, under Geological Setting, Australia and China out rank Poland and India by more than a factor of 5 in prospective CBM surface area. This distinction carries through to GIP and recoverable CBM as would be expected. In average Reservoir Properties, the differences are not as clear. India has the thickest coals but the permeability is low. Gas contents of the coals are similar for the four countries. In each of the countries, one or more of the sedimentary basins examined has favorable Logistics. Consequently, our preliminary conclusion from this review of the IEA GHG (1998) study is that Australia and China have the most potential for CO_2-ECBM.

Often coals basins around the world are compared to the San Juan Basin of the U.S. It should be noted that the coal reservoir properties of the San Juan Basin is an exception rather than the norm. The main coal-bearing sequence in the San Juan Basin is the Cretaceous Fruitland Formation which contains a stratigraphically concentrated coal package. Coal rank is medium volatile bituminous. Completable coal thickness averages about 20 meters. The gas-in-place resource in Fruitland coal seams is estimated at 1,420 Gm^3 (50 Tcf) with an average resource concentration of 270 Mm^3/km^2 (25 Bcf/mi^2). Gas content ranges from 7 to 20 m^3/t, averaging about 16 m^3/t. Most areas are gas saturated. The stress regime in the San Juan Basin is generally low, as is structural dip into the basin's center. The coal is extremely well cleated. Faulting is minimal with good reservoir continuity and lateral communication. Permeability ranges from 1 to over 100 md, averaging about 20 md. Typical permeability found in coal basins elsewhere ranges from 1 to 10 md. So in terms of geology, gas content, gas resource concentration and permeability, the San Juan Basin is a prolific CBM basin not found elsewhere.

Table 1.2: Summary of Four Country Coal Basin Appraisal from IEA GHG International (1998)

Sedimentary Basin	**Sydney**	**Bowen**	**Clarence-Morton**	**Upper Silesian**
Country (global ranking)	Australia (6)	Australia (4)	Australia (15)	Poland (16)
Geological Setting				
Total Size (km^2)	50,000	75,000	40,000	7,000
CBM Size (km^2)	15,000	25,000	8,000	5,000
Stress	mild compressive	mild compressive	tensional tectonics	mild compressive
Formations/Age	Illawarra/Permian	Moranbah - Rangal	Wallon/Jurassic	Ruda-Zabrze/C
GIP Gm^3 (Tcf)	2,040 (72)	2,940 (104)	875 (31)	415 (15)
CBM Conc Mm^3/km^2 (Bcf/mi^2)	170 (15.7)	134 (12)	117 (10.8)	110 (10)
Recoverable Gm^3 (Tcf)	205 (7.2)	590 (21)	175 (6.2)	20 (0.7)
Reservoir Properties				
Ind. Seam Thickness (m)	3 to 10	2 to 10	up to 2	up to 5
Cum. Seam Thickness (m)	30 over 250 interval	28 over 250 interval	10 to 40/< 1500m	40
Completable Thickness/Depth	15/700m	15/800m	20/800m	11/1150m
Permeability (md)	<1	1 to 10	2 to 10	1
Coal Rank	h-v bit.	m to l-v-bit.	h to m-v bit	h-v bit.
Ash Content (%)	15	15	15	15
Moisture Content (%)	5	5	5	2
Gas Content (m^3/t)	12	10	9	10
Gas Saturation	saturated	saturated	unknown	undersaturated
Cleating	moderate	good	good	Good
Mineralization	mineralized	minor		
Logistics				
market for gas	high/industry-urban	high/industry - urban	medium	High
Sources of CO_2/flue gas	high from coal	high from coal	low	High
pipeline/compression	pipeline access	pipeline access	pipeline access	Good

Sedimentary Basin	**Ordos**	**NE China**	**Damodar Valley**	**Cambay**
Country (global ranking)	China (13)	China (12)	India (10)	India (5)
Geological Setting				
Total Size (km^2)	250,000		3,600	13,000
CBM Size (km^2)	20,000	15,000	1,100	4,000
Stress	low stress regime	faulting, steep dips	mild compressive	extensional/faulting
Formations/Age	Shanxi - Taiyan/PC	Sha.-Tai. – Shihezi/PC	Barakar -Raniganj/P	Kadi - Kalol/P
GIP Gm^3 (Tcf)	2,220 (78)	1,110 (40)	440 (16)	1,000 (35)
CBM Conc Mm^3/km^2 (Bcf/mi^2)	123 (11)	111 (10)	470 (43)	250 (23)
Recoverable Gm^3 (Tcf)	445 (16)	55 (1.9)	22 (0.8)	100 (3.5)
Reservoir Properties				
Ind. Seam Thickness (m)	often above 2	1 to 4	up to 10 to 25	5 to 20
Cum. Seam Thickness (m)	25	20	100	65
Completable Thickness/Depth	12/1000m	10/900m	50/875m	40/1350m
Permeability (md)	1 to 10	0.1 to 1	1	0.5 to 2.5
Coal Rank	l-v bit. to semi-anthr.	m to l-v bit.	h to l-v bit.	lignite to sub bit.
Ash Content (%)	20	15	25	5
Moisture Content (%)	5	4	5	10
Gas Content (m^3/t)	11	11	10	5.5
Gas Saturation	saturated	saturated	saturated	unknown
Cleating	good	good	poor to fair	
Mineralization		Mineralized		
Logistics				
Market for gas	low	high industry - urban	high	high
Sources of CO_2/flue gas	low	high from coal	high from coal	high
Pipeline/compression	pipeline access	pipeline access	none	excellent

1.6 Report Outline

Although ECBM technology is being developed in North America, in the future it would have the greatest potential in countries where coal is abundant but the conventional natural gas supply is not. In order to move this technology towards wider acceptance, especially as a CO_2 sequestration measure, it is important that there should be successful CO_2 sequestration demonstrations. The IEA GHG has chosen China, India, Poland and Australia as targets to promote for demonstration of CO_2-ECBM. This study represents a first step in that direction by estimating the CO_2 sequestration potential of coal basins from available detailed geological and reservoir appraisals of basins in Australia, China, Poland and India; selecting preferred areas; and recommendation, design and costing of a CO_2 sequestration demonstration pilot.

As concluded in Section 1.5, based on IEA GHG (1998), Australia and China would appear to be the most favorable countries for a demonstration CO_2-ECBM project. This study examines the coal-bearing sedimentary basins from these four countries in greater detail to see if this gross ranking changes and to further assess the basins on a smaller scale by looking at individual sites in the basins which have potential for commercial sequestration/production. In the next 4 chapters, the four countries are examined. A description of the gas market for each country is followed by a general description of each coal basin which leads into reservoir details for the favorable CBM sites in that basin. A discussion of carbon dioxide sources and other factors close out each country chapter. Chapter 6 ranks the individual sites by 5 factors based on market potential, production potential, CBM resource/CO_2 storage potential, CO_2 supply potential and site infrastructure costs. An uncertainty factor is also included based on drilling density to weigh the ranking. Based on this method, the Bowen Basin in Australia contained the most favorable sites followed by the Qinshui Basin in China.

Chapter 7 contains the technical design for three CO_2-ECBM pilots progressing from a micropilot (1 well technical demonstration) through a full field pilot (5 well technical demonstration) to a 9-pattern (41 well commercial demonstration). It should be noted that a 41 well project would be considered commercial for primary production but not necessarily for CO_2-ECBM. The reason is that the CO_2 power plant sources being considered are so large and capture so expensive that a CO_2-ECBM commercial demonstration must be much larger than a primary CBM commercial demonstration. In the proposed micropilot, approximately 200 tonnes of CO_2 are injected over a week (i.e. 25t CO_2/day) into one well. In the proposed full field pilot, approximately 15,000 tonnes of CO_2 are injected over 6 months (i.e. 100t CO_2/day). Our proposed 41 well commercial demonstration is injecting approximately 400 tonnes of CO_2/day or 120,000 tonnes of CO_2/year compared to a 500 megawatt coal-fired power plant which emits over 10,000 tonnes of CO_2/day. At each stage, the source of CO_2 differs based on supply cost. At the micropilot stage, the gas is trucked in by tankers. At the full field pilot stage the gas is generated on site by using the exhaust gas generated by a gas engine or from a gas plant. At the commercial demonstration stage, the gas is delivered from a coal-fired power plant.

Chapters 8 and 9 are the financial review considering both primary and enhanced production by either injection of a pure CO_2 stream or injection of flue gas, for Australia and China respectively.

Chapter 10 reviews some implementation issues (regulations, financing, legal jurisdiction, safety, monitoring).

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CHAPTER 2
COUNTRY ASSESSMENT – AUSTRALIA

2.1 Australian Gas Market and Coalbed Methane

Australian Gas Market

In 1995, 35% of Australia's natural gas was consumed in the state of Victoria, 15% in New South Wales (NSW) and 6% in Queensland. Australia's gas consumption is expected to double by 2010, with Victoria dropping to 24% of the national total (although increasing in absolute terms), NSW consuming 16% and Queensland 12%. Much of the growth in consumption by the latter two eastern states is expected to be via electricity generation.

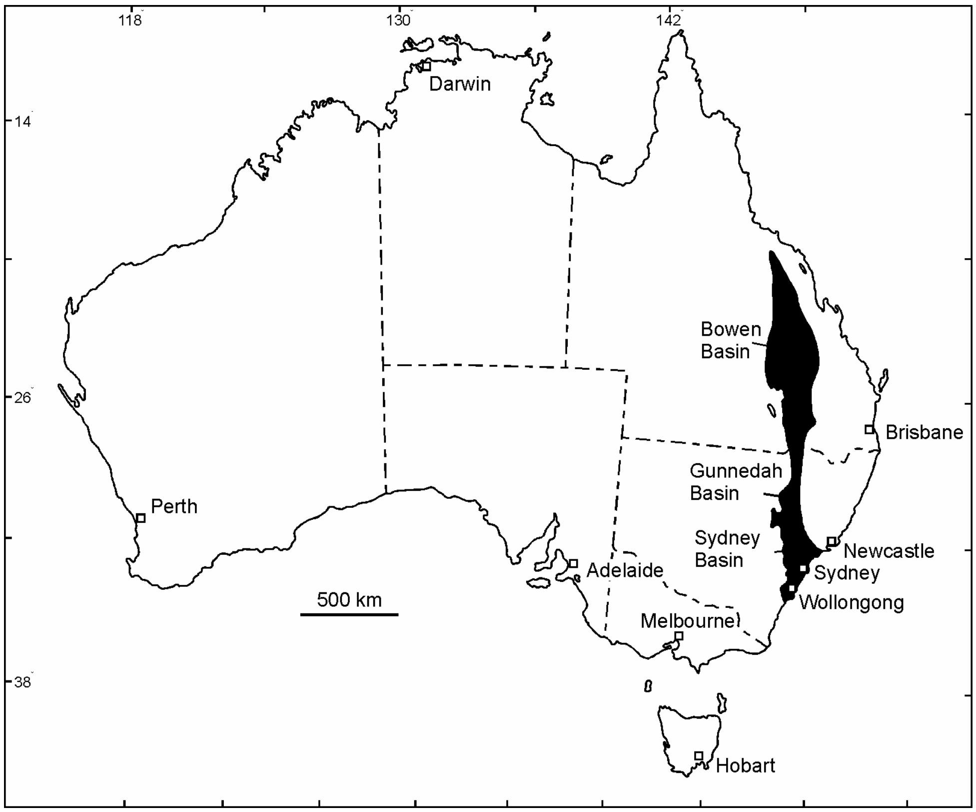
According to a recent Australian Gas Association study (1997), Australia has proved and probable gas reserves of 92,800 Petajoules or PJ (~86 trillion cubic feet) and potential additional resources of 30,000 PJ. Natural gas is presently meeting around 18% of Australia's primary energy requirements. Eastern Australia will require additional supplies of gas within the region (including increased production from existing basins and new production from coalbed reservoirs) to meet projected forecast demand between 2000 and 2008 and needs longer distance supplies to meet forecast demand in 2030. Eastern Australia may need to draw on additional supplies outside the region of up to 15,900 PJ in this period, whilst the Western Australian and Northern Territory region is projected to have a surplus of supply over demand of 17,800 PJ. Australia currently has 14,000 km of high-pressure transmission pipelines, but this will need to be expanded to connect additional reserves to eastern markets.

Australian Coal and Coalbed Methane

Australia has about 7% of the world's economically demonstrated resources of black coal (79 Gigatonnes), and very large but unquantified inferred resources. In terms of production, it ranks fifth after China, the USA, the former USSR and India. Total raw black coal production in 1998-99 was 286 million tonnes (Mt), of which 170 Mt was exported with a value of $A 9.5 Billion (about $US 5.7 Billion).

Most coal deposits are of Permian age (about 250 million years old), but younger deposits of Triassic, Jurassic and Cretaceous age are also important. The largest Permian deposits lie in the Bowen-Gunnedah-Sydney basin system that forms a major coal mining and coalbed methane resource across Queensland and NSW on the eastern flank of the Australian continent **(Figure 2.1).** Other Permian basins include the Galilee and Cooper Basins, which generally lie at greater depth.

Figure 2.1 Location of Bowen-Gunnedah-Sydney Coal Basins, Adjacent to the Eastern Seaboard of Australia.



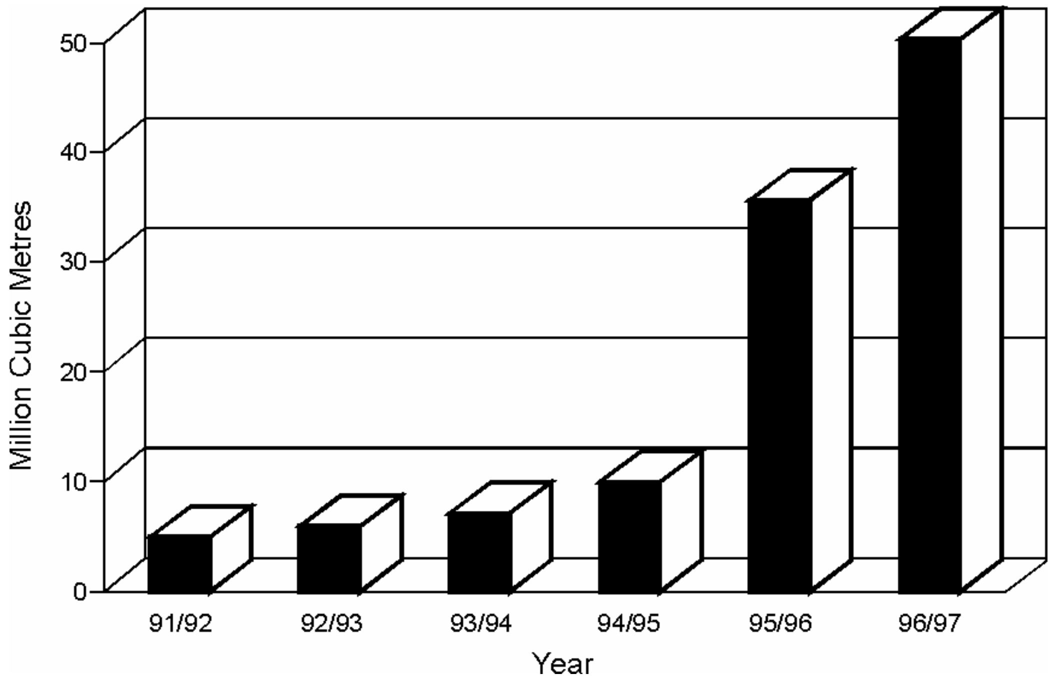
In 1997, 62 coal mining projects were operating in NSW, supplying 7 principal coal fired power stations ranging in capacity from 600 to 2,640 Megawatts (MW). This represents approximately 90% of the state's power production. Queensland had 31 coal mining projects; supplying 7 coal-fired power stations (range from 120 to 1,415 MW), which represents 75% of total production. In 1995-96, total black coal consumption in power stations was 44 Mt.

The most prospective seams for coalbed methane (CBM) production in terms of suitable depth, rank, low ash content, and thick aggregate sections are the deposits of the Bowen-Gunnedah-Sydney basin system. On the east coast, north of the Sydney Basin is the Clarence Morton Basin, which is of Triassic age. This basin is extensive in area, and has previously been assessed as having high gas-in-place (IEA Greenhouse Gas R&D Programme 1998). However, except at the shallow margins, there are insufficient reservoir data yet available to justify its consideration for a sequestration demonstration.

The level of CBM exploration and development in Australia has increased very significantly in the past several years, to the stage where modest commercial production is occurring or has been contracted from three fields in the Bowen and Sydney Basins. The development programs are accelerating. New production wells are being drilled, stimulated and completed for production testing in both of these basins. This is also true of the Gunnedah Basin, although commercial production has not yet occurred. Analysis by the Queensland Department of Minerals and Energy quantifies this acceleration, showing the

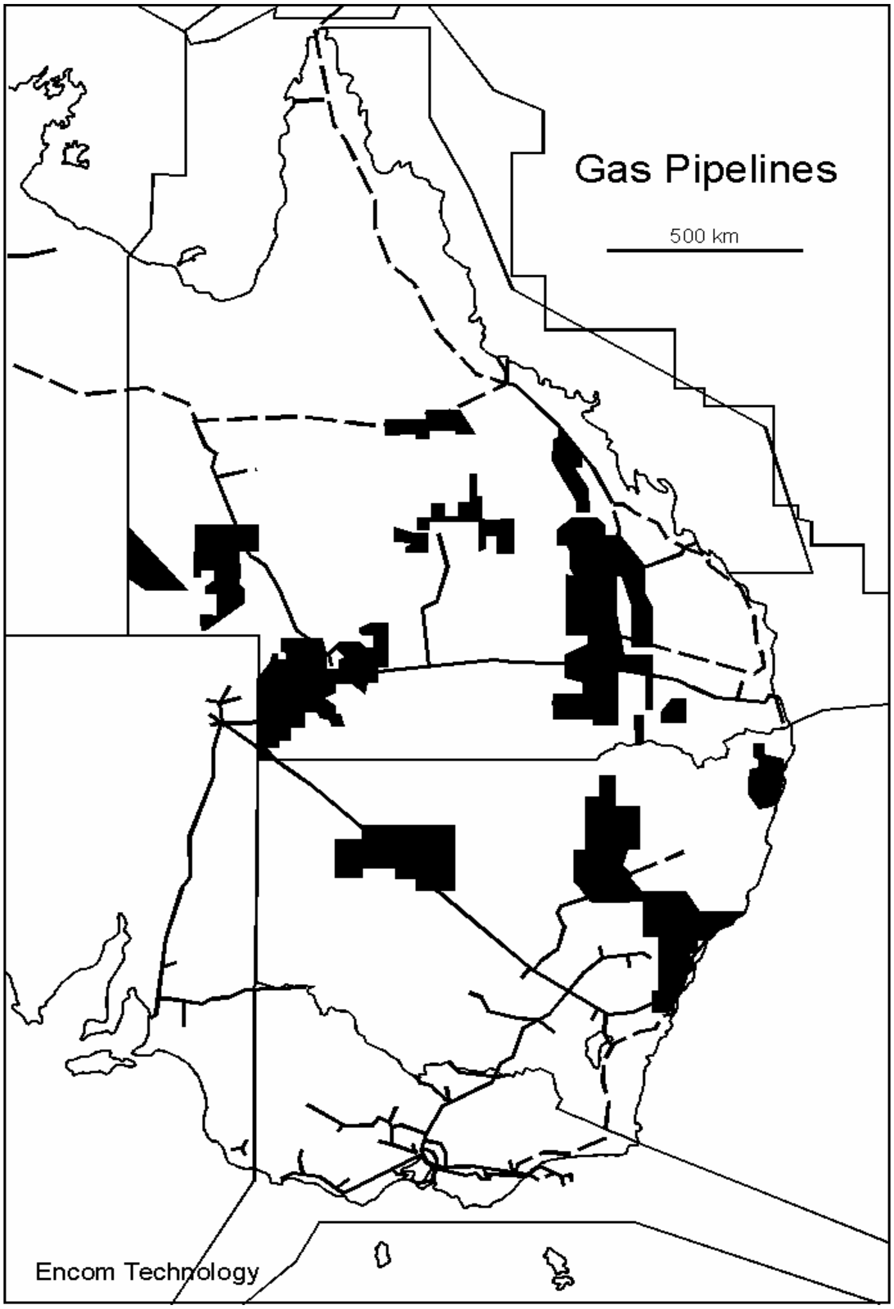
CBM annual production steadily increasing reaching 50 Mm^3 (1.7 Bcf) by the year 1997. (**Figure 2.2**).

Figure 2.2 Growth of Queensland CBM Testing and Production to 1997.



The Bowen, Gunnedah and Sydney Basins are adjacent to the major population and industrial centres in the states of NSW and Queensland. These are served by an extensive network of gas pipelines, extending from the central and southern Queensland coast to the coalbed methane and conventional gas producing areas in central Queensland, and linking southward to the NSW and Victorian networks **(Figure 2.3).**

Figure 2.3 Existing and Projected Gas Pipelines in Eastern Australia; Also Showing Current CBM and Conventional Gas Fields.



2.2 Geological Settings

2.2.1 Bowen Basin

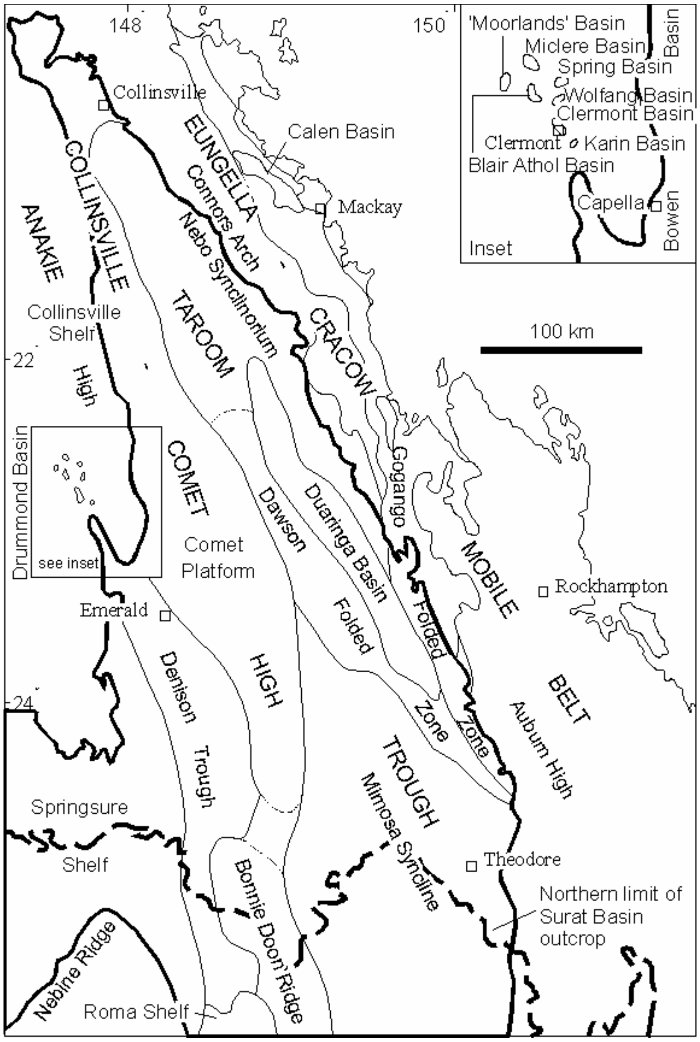
Presently there are 11 Authorities to Prospect (ATP) in the Bowen, Surat/Bowen and Eromanga/Gallilee Basins having CBM as the sole target, and another 3 ATPs in the Surat/Bowen Basin that are targeting both CBM and conventional gas.

The Bowen Basin covers an area of 75,000 square kilometres (km^2) and has inferred coal reserves of greater than 114 Gigatonnes (Miyazaki and Korsch, 1993). Assuming a prospective basin area of 22,000 km^2, a pro-rata estimate of contained coal resource available for CO_2 sequestration is 34 Gigatonnes (Gt or 10^9 tonnes). This compares with the more optimistic estimate of 350 Gt given in the 1998 IEA Greenhouse Gas R&D Programme Report (IEA GHG). Miyazaki and Korsch (1993) estimated the net area across the Bowen and Sydney Basins combined which met a set of conservative criteria for CBM production at 20,000 km^2, corresponding to 218 Gt of coal and 1,760 Gm^3 (10^9 m^3) of recoverable gas-in-place. Although conservatively based, these estimates nevertheless demonstrate the very large potential CBM resources, and by inference a very large potential for CO_2 sequestration and enhanced coalbed methane (ECBM) recovery.

Structural sub-divisions of the Bowen Basin are shown in **Figure 2.4**. Broadly the basin has four major tectonic elements: the Taroom Trough, the Collinsville-Comet High (Ridge), the Denison Trough and the Springsure Shelf, and these in turn consist of lesser sub-divisions (Harrington et al., 1989). The Taroom Trough occupies the eastern half of the basin, and is bisected by the Dawson Folded Zone into the Nebo Synclinorium (north) and the Mimosa Syncline (south). Along the northwestern basin margin, and extending southward along the western side of the Mimosa Syncline is a basement high called the Collinsville-Comet High. Southward it becomes a ridge, in contrast to the lows on either side. The northern end of this ridge is called Comet Ridge, separated by a saddle from the southern end.

The main regional structures are steeply dipping NNW-SSE striking faults, and steep NE-SW faults. The latter are thought to occur in the basement. They roughly parallel the directions of maximum compression and extension imposed on the basin. Major faults are from 60 to 100 km apart, and mark the termination of very large structural elements in and around the basin. Within each domain smaller faults are spaced at 10 to 20 km. The surface expressions appear to delineate NE - SW "corridors" (Enever et al., 1990). From 181 stress measurements performed across the basin using stress relief methods and hydraulic fracturing to depths of ~680 metres (m), the orientation of maximum horizontal stress is N - NE. This is found to be consistent on a 100 km scale and a 500 km scale (Hillis et al., 1999). Analysis of stress component ratios indicate that 80% of the measurements suggest reverse thrust conditions, 17% strike slip conditions, and only 3% normal faulting conditions. However, it is noted that the Bowen Basin is relatively a-seismic compared with the Sydney Basin (see below).

Figure 2.4 Geology Structural Sub-Divisions of the Bowen Basin



In some CBM stimulation trials in the Bowen Basin, stresses have been measured and combined with structural data for numerical analysis and design of treatments (Jeffrey et al., 1992; Wold et al., 1995). A general trend from micro-frac and step-rate tests in the coal intervals is that the minimum stress in the coal is about 60% of the vertical overburden stress (Enever, 1993). This can be considered a favourable condition for CO_2 injection and ECBM, in terms of effective permeability of the target formations. Under these conditions, low effective stress and enhanced permeability can be achieved at moderate treatment pressures and compression costs.

Bowen Basin coal sequences occur in four distinct groups, aged from earliest Permian (Group I) to late Permian (Group IV) (Mallett et al., 1991). Group I coals are largely confined to graben and half-graben in the Denison Trough. The seams range up to 30 m in thickness and are low ash, high volatile bituminous type. Vitrinite reflectances (Vro which are a measure of coal rank) range from between 0.66 and 0.74% at 350-metres depth to 0.8 and 0.9% at 1,000-metres depth. Vro for a high volatile A bituminous coal would be about 1%. The Denison Trough remains relatively unexplored but is considered to have good exploration potential. The Group II coals include the Blair Athol Coal Measures in the west, which are generally shallow, and the Collinsville Coal Measures in the north, which have high CO_2 levels, of magmatic origin. These are not regarded as good CBM prospects. The Group III coals include the Moranbah Coal Measures and the German Creek Formation. The coals are medium volatile bituminous, with cumulative thickness from 10 to 20 m. Vitrinite reflectances range from 1.0 to 1.6%. Gas contents of 13.3 to 16.6 m^3/t at depths of 468 to 612 metres have been reported.

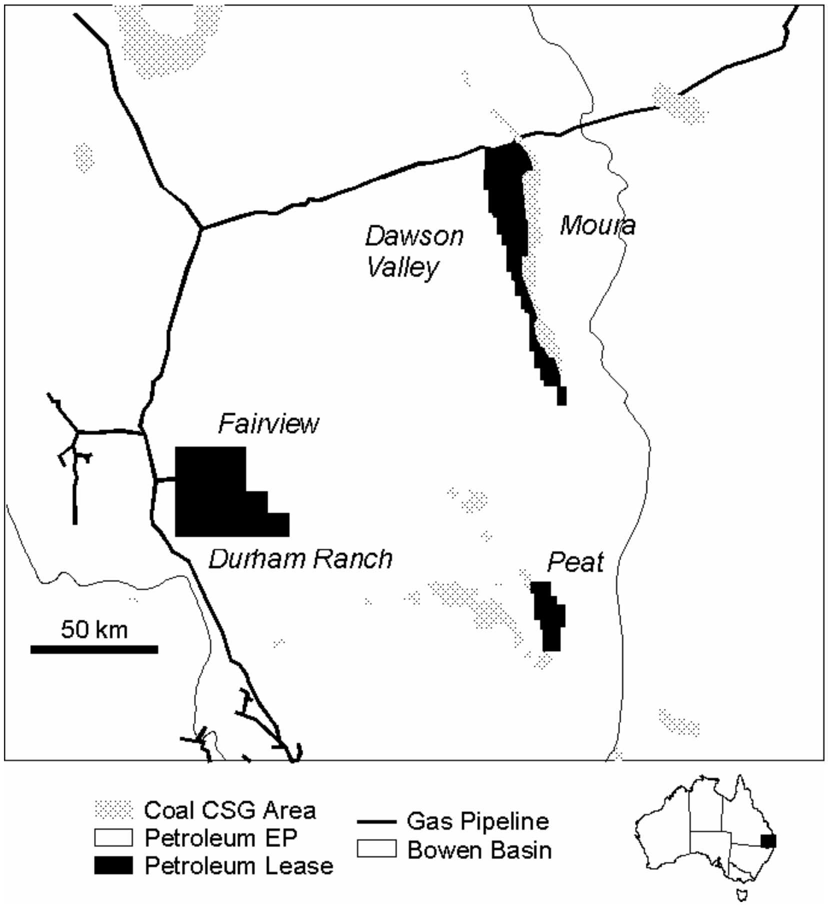
The Group IV coals cover the full extent of the Bowen Basin and are represented by the Rangal and Baralaba Coal Measures and equivalents in the Bandanna Formation. The sequence thickens from north to south and from east to west. In the southeast, cumulative thickness reaches 20 m. Reflectances range from 0.9 - 1.8% at shallow depth in the north to 1.2 - 1.6% in the central basin. Further south in the Blackwater area more than 20-metres cumulative thickness occurs in 4 to 8 seams. Gas contents of up to 18 m^3/t have been reported at 600-metres depth.

The two areas of the southeast/southwest Bowen Basin in which currently produce commercial gas are the Dawson River/Moura and the Fairview/Durham Ranch fields. Reservoir conditions and well development experience in these fields reflect the quite distinct differences in their structural settings. Further south of these two areas is the Peat field, in which a number of exploration and appraisal wells have been drilled in the last several years.

Dawson Valley Field

The Dawson Valley Field comprises the Dawson River/Moura areas, which lie in the southeast district of the Bowen Basin, where the Baralaba Coal Measures outcrop (**Figure 2.5**). This area is east of the Taroom Trough and Mimosa Syncline. Total thickness of the coal measures ranges from 300 to 350 m. The coal measures comprise an upper coal bearing member, typically 220 m thick and a lower section, the Kaloola Member, which contains 90 to 120 m of interbedded tuffaceous sediments with minor coal seams. The Baralaba Coal Measure sequence dips at 10 to 20 degrees to the west, towards the Mimosa Syncline and is overlain by the Triassic Rewan Formation.

Figure 2.5. Location Plan of Active CBM Fields in the Southern Bowen Basin.



Structurally, the Baralaba Coal Measures in this region are characterised by a predominance of thrust related faulting, evident in coalface exposures at the Moura Mine. Intensity of thrust faulting increases toward the north and decreases toward the Dawson River field in the south.

Cleats are well developed within bright coal bands, but are rarely developed in dull bands. Mineralisation occurs in the cleats as clay minerals, including small amounts of smectite, and as carbonates (calcite, ankerite and siderite).

Dawson River: The Dawson River field occupies an area of about 242 km^2 with an estimated gas-in-place volume of 58 Gm^3. The CBM concentration is very high at 240 million cubic meters per square kilometers (Mm^3/km^2). The Baralaba coal is late Permian in age. Formation stress is mainly moderately compressive and the maximum horizontal stress is oriented in a N - NE direction. More than 27 wells have been drilled so far at Dawson River, with a further 7 at the associated Nipan field. Oil Company of Australia (OCA) operates the Dawson River field. Typical reservoir parameters for the Dawson River field are shown in the **Table 2.1.**

Table 2.1: Typical Reservoirs Parameters for the Dawson River Field

Individual Seam Thickness	1.5 – 3.5 m
Cumulative Seam Thickness	20 – 25 m
Completable Thickness/Depth	20-25/> 420 m
Permeability	2 – 19 md, mean ~5 md
Coal Rank	High volatile bituminous, Vitrinite Reflectance (Vro) 0.9 – 1.8%
Ash Content	Low-medium ~ 7 – 8%
Moisture Content	~ 1%
Gas Content	5 – 14, generally > 11 m^3/t
Gas Saturation	High
Cleating	Variable, well developed in face cleat in bright bands
Mineralization	Variable, present as calcite and clay minerals

At Dawson River No. 2 well, eight seams were intersected between 421 to 628 metres depth, with a cumulative thickness of 23 metres. Permeability thickness product at this location was measured to be 181 md-m. In the uppermost seam, Nipan 0, interference well testing indicated mean permeability of 4.8 md over interwell distances of about 90 m. Gas contents range from 6.1 - 13.5 m^3/t, generally exceeding 11 m^3/t. The reservoirs are normally pressured and in most cases, the desorption pressure is close to the reservoir pressure.

Further west at Dawson River No. 23 well, 9 seams occur at depths from 530 to 835 m. For the field, the average thickness of the coal measures is 300 m, average net coal thickness is 20 m and the average number of seams is 11.

Recent development has focussed around economically productive wells associated with an anticlinal nose, the Malakoff structure, located between the Dawson River and Nipan areas (Falkner, 1999). These have included both field development wells to maintain production, and step-out appraisal wells.

Well costs are estimated at about $A 500,000 (about $US 300,000). Typical gas flow rates are 300 thousand cubic feet per day, or 300 Mcfd (~8,500 m^3/d) with water flow rates at 200 barrels per day (~32 m^3/d). Dawson River 28 well came on-stream at ~1,000 Mcfd (28,300 m^3/d). Total current gas production is about 4,000 Mcfd (~113,000 m^3/d). Production at 2 PJ per year over 10 years is considered possible, and an expansion by 50% is anticipated with further drilling.

Moura: The Moura field is currently a small operating field within ATP 364P, which encompasses an area of 8,000 km^2. The CBM concentration is estimated at 180 Mm^3/km^2, based on four main seams. BHP Petroleum Pty. Ltd. operates the Moura field. Current operation targets the upper-most seam only. As in the Dawson River field, the Baralaba coal is late Permian in age. Formation stress is mainly moderately compressive and the maximum horizontal stress is oriented in a N-NE direction. Typical reservoir parameters for the Moura field are shown in **Table 2.2.**

Table 2.2: Typical Reservoirs Parameters for the Moura Field

Individual Seam Thickness	1.5 – 7 m
Cumulative Seam Thickness	16 – 18 m
Completable Thickness/Depth	10-18/> 300 m
Permeability	1 – 3 md
Coal Rank	High medium volatile bituminous, Vitrinite Reflectance (Vro) ~ 1.0%
Ash Content	Low-medium ~ 8%
Moisture Content	~ 2%
Gas Content	10 –15 m^3/t
Gas Saturation	High, isotherm data available
Cleating	cleat present in bright bands; larger scale fracture systems present
Mineralization	Calcite in upper seams, decreasing presence in lower seams

The Moura field is atypical as a CBM development in that production is from sub-horizontal in-seam drilling from open pit exposure. The coal sequence comprises 5 seams with thickness in the range 1.5 to 7.0 m. In the uppermost seam, wells are drilled to lengths exceeding 1,700 m from the face. At depth, gas contents of 10-15 m^3/t are encountered. 27 wells have been drilled so far at 200 m spacing. Well costs are less than $A 200,000 (about $US 120,000). Permeabilities are in 1 - 3 md ranges, similar to that at the nearby Dawson River field. Initial gas flows are typically 300 to 350 Mcfd (8,500 - 9,000 m^3/d), decreasing to about 150 Mcfd (~4,250 m^3/d). Total production is about 3,000 Mcfd (~85,000 m^3/d), but many wells are currently shut in. With an expanded drilling program planned, 5,000 Mcfd (~142,000 m^3/d) over 20 years can be projected. To the north of the Moura Mine, ATP 364P is about 8,000 km^2, with coal depths up to 600 m, and good prospectivity. However, it is apparent that development of ATP364P will require improved security of market for gas produced.

First commercial production commenced in 1996 from Dawson Valley to the coastal city of Gladstone from 12 wells in each field. Approximately 4,000 PJ/day is produced via a 47 km pipeline into the Wallumbilla to Gladstone pipeline.

Fairview and Durham Ranch Fields

The Fairview and Durham Ranch fields are sited on the Comet Ridge, on the western flank of the Taroom Trough/Mimosa Syncline (Scott, 1998). The Comet Ridge is a basement high that separates the Taroom Trough from the Denison Trough. The target seams are in the Bandanna Formation, which are the stratigraphic equivalent of the Baralaba Coal Measures in the eastern basin (Dawson Valley area) and the Rangal Coal measures in the north and central Bowen Basin.

Fairview: At Fairview, the top of the Bandanna Formation has been taken as the top of the upper coal seam. At this location two well-developed coal seams are found in the formation. The upper seam is 4.9 to 6.4 m thick across the field. Well logs indicate consistently bright coal across the field. Seam splitting is evident in some locations, with typically >7 m cumulative coal in about 25 m of strata. The lower seam has consistent thickness in the range 3.0 to 3.7 m, but some splitting occurs with increased shale content, and generally less CBM prospectivity. Little analytical information is available from Fairview. From the upper seam, at depths of 720.2 m and 726.6 m, vitrinite reflectance was measured at 0.89% and 0.85% in two wells. Typical reservoir parameters for the Fairview field are shown in the following Table.

Table 2.3: Typical Reservoirs Parameters for the Fairview Field

Individual Seam Thickness	3.0 – 6.4 m
Cumulative Seam Thickness	7 – 10 m
Completable Thickness/Depth	7-10/700 – 800 m
Permeability	Large implied from production testing of cavity completed wells
Coal Rank	High medium volatile bituminous, Vitrinite Reflectance (Vro) ~0.7 – 0.89%
Ash Content	N/a
Moisture Content	N/a
Gas Content	Estimated at > 12 m^3/t, no data available
Gas Saturation	High, possible indications of free gas /overpressure
Cleating	Open cleating and friable coal
Mineralization	None apparent

TriStar Petroleum is the owner of the Fairview field. CBM area covers about 693 km^2 (PL 90, 91 and 92). Based on a gas-in-place volume estimate of 65 Gm^3, the CBM concentration is then 94 Mm^3/km^2.

In contrast to the Dawson Valley, the field is located on a broad anticlinal structure, with apparently low horizontal stresses and high permeability. To date, 22 wells have been drilled at an average depth of 801 m. A number of wells have been successfully completed using cavitation methods. Initial gas flows of up to 3,000 Mcfd (~85,000 m^3/d) have occurred in some wells, tending to stabilise at about 1,000 Mcfd (~28,300 m^3/d). Some wells have produced gas at 1,000 Mcfd (~28,300 m^3/d) with little water, indicating high levels of gas saturation; others have produced high initial water rates with subsequently increasing gas production, indicating high permeability but under-saturated gas conditions. Total production is currently thought to be about 5,000 Mcfd (~142,000 m^3/d). Commercial production is currently ~7,000 PJ/day via an extension to the Wallumbilla to Gladstone pipeline.

Durham Ranch: Durham Ranch is a new field operating over the Comet Ridge, adjacent to and under similar conditions to Fairview. The area of the resource is 20,000 km^2. Typical reservoir parameters in the Durham Ranch field are shown in **Table 2.4**.

Table 2.4: Typical Reservoirs Parameters for the Durham Ranch Field

Individual Seam Thickness	3.0 – 6.0 m
Cumulative Seam Thickness	~ 9 m
Completable Thickness/Depth	5-9/> 680 m
Permeability	Implied high
Coal Rank	High medium volatile bituminous, Vitrinite Reflectance (Vro) >0.7%
Ash Content	Low
Moisture Content	N/a
Gas Content	N/a
Gas Saturation	Implied high
Cleating	Implied open cleating and friable coal
Mineralization	None apparent

Area for the Durham Ranch field is 691 km^2 (PL 123, 124 and 125). Gas-in-place volume is estimated at 65 Gm^3, extrapolating from the adjacent Fairview field. The CBM concentration is then 92 Mm^3/km^2.

Transfield and TriStar Petroleum are the owners of the Durham Ranch field. To date, 9 wells have been drilled at an average depth of 859 m. High permeability has been encountered, with 3 of the wells producing initial gas flows of greater than 1,000 Mcfd (including 1 well at >8000 Mcfd (>226,400 m^3/d). Stabilised rates of 500 – 1,000 Mcfd (~14,200 - 28,300 m^3/d) are expected to be reached. Water rates of up to 1,000 barrels per day (159 m^3/d) occur in some wells. A total of 20 wells is planned for the initial development, with a field production of 12,000 Mcfd (~340,000 m^3/d). A 90 km pipeline extension is planned to enable the field to be linked to Brisbane, and 675 km pipeline link to Townesville in north Queensland.

Peat Field

***Peat**:* The Peat field lies near Wondoan, south of the Dawson Valley, and in the last two years Oil Company of Australia has 10 exploration and appraisal wells drilled at this site. The field is sited on the Burunga Anticline and contains a gas cap in the thick coals of the Baralaba Coal Measures. Five production wells were drilled in the gas cap and fracture stimulated in both the Baralaba coals and the lower Kaloola Member. All wells free flowed gas at commercial rates. Outside of the gas cap, 2 other wells were stimulated by cavitation and fracturing respectively, and have apparently flowed promising gas rates after early water pumping. The holders of the Petroleum Exploration Licenses (PEL) have recently built a 75 MW gas fired power station at Roma, at which three natural gas pipelines converge. The Peat field operators are contracted to supply gas at ~ 6 PJ per year to a major new oil refinery near the Queensland capital, Brisbane.

2.2.2 Sydney Basin

The Sydney Basin is an approximately north-south trending basin centred around Sydney on the east coast. It is approximately 350 km long by an average of 100 km wide, with a total onshore area of 44,000 km^2 (Brown et al., 1996). It comprises five main coalfields; the Hunter and Newcastle Coalfields in the north, the Southern Coalfield, the Western Coalfield and the currently inactive Central Coalfield. The Sydney Basin is separated from the Gunnedah Basin on its northern boundary by the Liverpool Range.

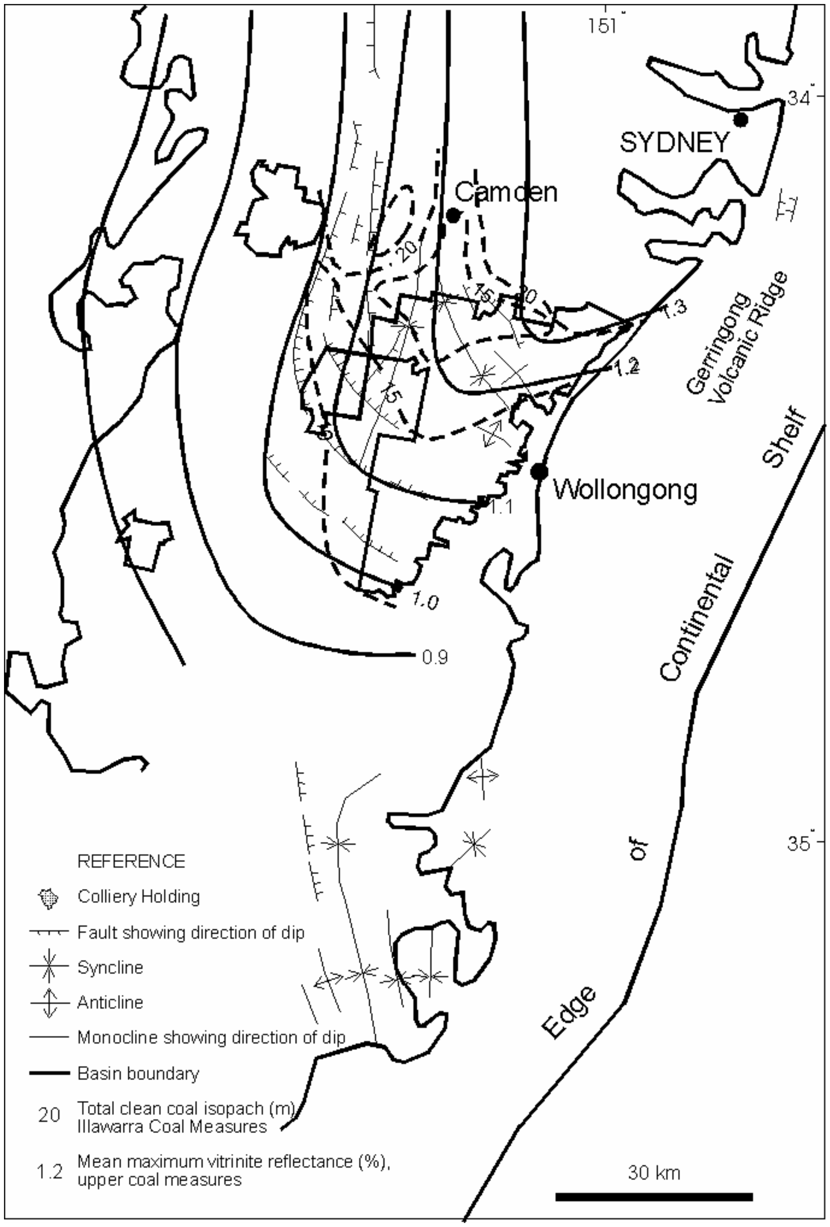
There are three major population centres in the Basin - Sydney (4 million people), Newcastle to the north (600,000), and Wollongong to the south (400,000). These cities have reticulated gas and several oil refineries. A number of coal-fired power stations are situated along the basin margins. Competing land uses include national parks, open cut and underground mines, and urban development.

A large database of coal geology and coal gas reservoir properties has accumulated from limited petroleum exploration drilling and from the many coal-mines operating around the shallow margins of the basin, of which some have severe gas drainage problems. Of the five coalfields, the Southern Coalfield is considered the most prospective for CBM and is the only one in the Sydney Basin, which will be considered here. The Southern Coalfield is adjacent to the Moomba - Sydney natural gas pipeline.

The Southern Coalfield covers an area of about 3,000 km^2, with much of the central and eastern portion occupied by colliery holdings. Because of these holdings and topographical features, CBM prospectivity is restricted to the western area of the field.

The main coal bearing succession of the Southern Coalfield is the Illawarra Coal Measures of late Permian age. These are deposited in the uppermost Sydney Subgroup. The major coal units comprise the Bulli (2.7 m thick), Balgownie (3.1 m), Wongawilli (13.4 m) and Tongarra seams (3.8 m). Less continuous units comprising the Cape Horn, American Creek and Woonona seams also occur. **Figure 2.6** shows the total clean coal isopach and vitrinite reflectance for the Illawarra Coal Measures. Typically, total thickness of 15 to 25 meters-coal lies within a 250 to 300 m interval. Depths to the top of the Bulli Seam are greater than 600 m in the non-mining areas in the south-western region of the coalfield. The coals are of high volatile bituminous to medium low volatile bituminous, with vitrinite reflectances in the order of 1.2% and low ash content. The seams are normally pressured and high gas contents are commonly recorded, up to 15 m^3/t in the uppermost Bulli seam, and generally >10 m^3/t. The reservoirs are normally pressured and gas contents are often close to saturation. Cumulative thickness of 25 m occurs in the Camden region, from which commercial CBM production is about to commence. This field has an area of 430 km^2 with gas in place of 74.2 Gm^3 and recoverable resource 14.8 Gm^3.

Figure 2.6 Southern Sydney Basin, Illawarra Coal Measures; Total Clean Coal Isopach and Vitrinite Relectance. Note Structural Information.



The major structural element of the southern Sydney Basin is the broad N-S Camden Syncline, the axis of which lies along the centre of the basin (Faiz and Hutton, 1997). The western limb of the syncline is characterised by N-S and NNW-SSE trending monoclines. The folding is gentle with most structures plunging northwest with regional dips of <5 degrees. CH_4 is the predominant gas in structural lows, including the Camden Syncline, but CO_2 contents increase in regions of structural highs. Very high CO_2 contents can be associated with igneous intrusions. Wet gas content increases with depth from very low values at <500-m depth to >12% at 1,200 m-depth.

From 206 stress measurements across the Sydney Basin, the stress orientations are more variable than in the Bowen Basin, with no consistency across a scale of >100 km (Hillis et al., 1999). In the Southern Coalfield the mean orientation of maximum horizontal stress from 72 measurements is ENE-WSW. The fault condition appears predominantly more reverse than the Bowen Basin (90% of the measurements), strike-slip (8%) and normal fault condition 2%. Typical horizontal to vertical overburden stress ratios is in the range 1.5 to 2.0. It is interpreted that the more complex structural fabric of the Sydney Basin together with higher levels of stress may play a role in higher levels of seismicity observed in the Sydney Basin compared with the Bowen Basin.

Permeability data available from well tests and from tests on core indicate low permeability at reservoir effective stress conditions (1 md or less). However, results from recent production test wells indicate much higher permeabilities (see Camden Area).

Camden Area

The Camden area is situated about 50-km southwest of Sydney in the Southern Coalfield. Results from a Government drilling program for a coal resource block of 275 km^2 have provided coal quality data and some reservoir parameters for the Illawarra Coal Measures in this region, from the uppermost Bulli coal down to the Woonona member. Desorbable seam gas resources for the target block were 25.5 Gm^3, with desorbable gas content in the Bulli seam averaging 11.0 m^3/t (thickness range 2.63 - 5.0 m); Balgownie Seam 10.0 m^3/t and Cape Horn seam 12.0 m^3/t.

CBM development of the Camden area has begun. CBM area in the Camden field covers 430 km^2. Gas-in-place volume is estimated at 74 Gm^3, showing a CBM concentration of 172 Mm^3/km^2. So far, Sydney Gas Company has drilled and fracture stimulated 12 wells in an initial program of 25 wells. In the Bulli seam at depth 677 m, well tests have indicated higher than expected permeability, ranging from 12 to 36 md, with water flows to 1,200 barrels per day (~191 m^3/d) from one well. Recently, commercial supply of gas from this new field has been contracted for supply into the Sydney market. Typical reservoir parameters for the Camden field are shown in **Table 2.5.**

Table 2.5: Typical Reservoirs Parameters for the Camden Field

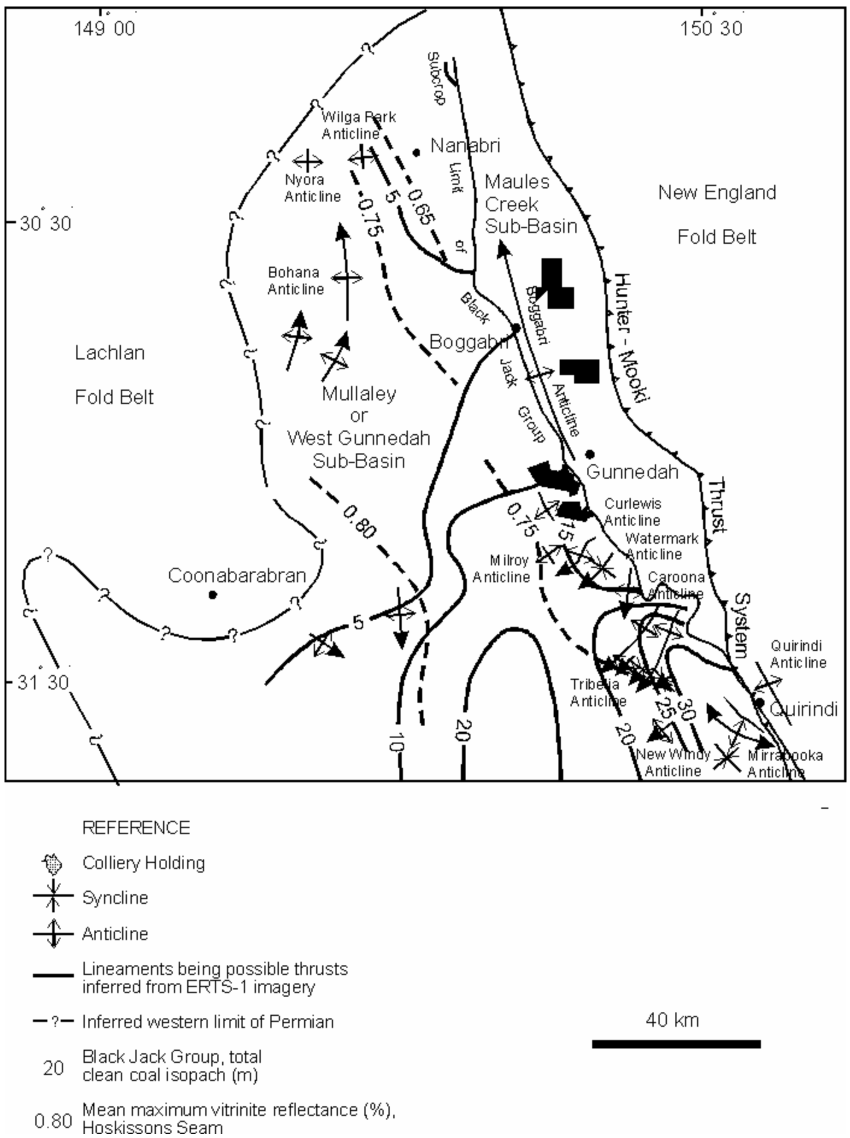
Individual Seam Thickness	0.5 – 15.0 m
Cumulative Seam Thickness	15 – 25 m over 300 m intervals
Completable Thickness/Depth	10 – 15 / > 670 m
Permeability	Variable; 1 md in some areas, 12-36 md reported from CBM production wells
Coal Rank	High to medium volatile bituminous, Vitrinite Reflectance (Vro) 0.7-1.6%
Ash Content	Medium (10-20%); high in some seams (50%)
Moisture Content	1 – 2%
Gas Content	10-15, average 11 m^3/t
Gas Saturation	High, isotherms available
Cleating	Well developed in bright bands
Mineralization	Present in some areas

In the coal mining areas east of Camden, mine gas drained from the Bulli seam at the Tower and Appin Collieries is used to fire a 95 MW power station that delivers to the commercial grid.

2.2.3 Gunnedah Basin

The Gunnedah basin extends north from the Liverpool Range as a progression of the Sydney Basin. It is centred some 250-300 km from the east coast, in a predominantly rural setting with relatively small land use competition compared to the Sydney Basin. It has an area of 15,000 km^2 and geologically can be divided by the Boggabri Anticline into the Gunnedah West sub-basin and the Maules Creek sub-basin on the east (**Figure 2.7**). In the north, bedding generally dips west except on the eastern side of the Boggabri anticline, where the Maulers Creek sub-basin dip 2 to 5 degrees to the east. The stress regime is mainly compressional. Several structures are mapped southeast of the Boggabri Anticline, but until very recently have generally not been explored and mapped elsewhere in the basin. Extensional structures exist both in anticlines and as a result of doming above igneous intrusions.

Figure 2.7 Gunnedah Basin; Total Clean Coal Isopach for the Black Jack Group and Vitrinite Reflectance of the Hoskissons Coal Seam.



In the Gunnedah West sub-basin, the coals of the Black Jack Group have widespread distribution and lateral continuity. These are the lateral equivalent of the Fairview coals in the Bowen Basin. Within a sediment thickness of 50 to 100 m in the north, coal reservoir thickness of 5 to 10 m net clean coal is present. The main basal Hoskisson seam in particularly is regarded as a good CBM target. The Hoskisson coal ranks in the High Volatile Bituminous range (vitrinite reflectance 0.65 - 0.80%), with rank increasing from east to west and towards the southeastern corner. Ash content is medium to high ash content (15-30%). Igneous intrusions occur in various localities, with the possibility of locally degraded coal quality and increased CO_2 content.

To the southeast, total coal thicknesses increase to 30 m where the Black Jack Group thickness approaches 500 m. Much of the southern Gunnedah Basin has an average total thickness of 20 m-coal over a consistent 250-300 m interval. Assuming a 10 m thickness cut-off approximately 4,750 km^2 contains gas-in-place of 731 10^9 m^3, prospective along the western-central edge of the basin. If a 5 m cut-off is used, an additional 2,000 km^2 and 130 10^9 m^3 resource exists in the southeast.

Narrabri Field/Bohena Project: Recent intensive exploration and assessment well drilling at the Bohena project in Petroleum Exploration License (PEL) 238 has established very promising results (Decker, 1999). In 12 months to February 1999, extensive seismic data were recorded and existing data reprocessed, leading to the identification of 15 new anticlines. First Source Energy/Force Energy drilled 15 wells in this area, of which 2 were cavity completed and 7 fracture-stimulated. High gas flow rates occurred at 2 wells, including one measured at >2,000 Mcfd (~56,600 m^3/d). Water production rates range from 100 to 350 barrels per day (~16 to 56 m^3/d).

PEL 238 includes both the Maules Creek Formation at depths of 700 - 900 m and the Black Jack Group at depths of 500-600 m. The Bohena Project area contains an average 16.2 - 21.6 m of coal over a stratigraphic interval ranging between 36.6 - 45.7 m thick. A basal seam varies between 4.6 and 12.2 m thick. Gas content averages 15.3 m^3/t, based on a dry-ash-free basis. CBM concentration calculated on this basis is 320 to 440 Mm^3/km^2. This is in contrast with the basin-wide calculation of about 130 Mm^3/km^2 (860 Gm^3 over area of 6,570 km^2). A probable explanation is a gas cap. The Black Jack Group and Maules Creek formation are late Permian in age. The formation is generally compressive, with some extensional structures on anticlines and over intrusive domes. Typical reservoir parameters for the Narrabri/Bohena field are shown in **Table 2.6.**

Table 2.6: Typical Reservoirs Parameters for the Narrabri/Bohena Field

Individual Seam Thickness	1.5 – 12.2 m, average 10 m for Hoskissons seam and 2 – 6 m for Black Jack group
Cumulative Seam Thickness	16.2 - 21.6 m Black Jack formation; 4.6-12.2 m basal; 1.5 - 3.5 m Maules Creek formation
Completable Thickness/Depth	5 – 20/> 500 - 700 m
Permeability	18 - 36 md from well tests
Coal Rank	High volatile bituminous, Vitrinite Reflectance (Vro) 0.65-0.8%
Ash Content	Medium high (15-30%);
Moisture Content	Not known
Gas Content	~15 m^3/t
Gas Saturation	Saturated, overpressured in some areas
Cleating	Little knowledge
Mineralization	Not known

Clean coal thickness in the range 20.9 to 30.7 m has been encountered in Maules Creek coals. They have been established as gas saturated and highly permeable. Drill Stem Test (DST) analysis in one well indicated permeability of 18 md at 920 m depth, and in another well 36 md at 887 m. Both wells were over-pressured with a gradient of 0.48 psi/ft (10.9 kPa/m).

2.3 Basin Evaluation

The Bowen, Gunnedah and Sydney Basins can all be considered as potential targets for CO_2 sequestration and ECBM operations. While only one basin might ultimately be chosen for further consideration in this study, the influence of factors other than geology and reservoir characteristics will vary between fields and may moderate the choice. These factors include competing land uses, underground mining operations, and proximity to power stations and potential CO_2/flue gas sources. Therefore, the three basins are all considered in the initial assessment. Taking the view that a CO_2 sequestration/ECBM proposal would be most prospective for implementation in an area of demonstrated CBM potential, the currently most active areas are targeted. This is because these areas are likely to provide the most reliable guide to suitable reservoir conditions for CO_2 sequestration e.g. permeability, and also because economic considerations suggest that ECBM will be an essential component for operational viability.

However, it is noted that commercially valuable reservoir and production information is generally tightly held by leaseholders and operators. Therefore current information is fairly sparse, and extrapolation of open file data is required. A general resource analysis for the major basins was previously reported (IEA GHG 1998). The current report should be read in conjunction with the earlier report (which is summarized in Table 1.2).

Suitability of Australian Basins for CO_2 Sequestration and ECBM

The previous IEA study ranked the world's most prospective coal deposits for CO_2 - ECBM recovery potential (IEA GHG 1998). Exhibit 6-10-1 in that report ranks the Bowen Basin first outside of the USA, and the Sydney Basin third. The Gunnedah Basin was not considered adequately prospective in that assessment.

The information contained in the current assessment supports the high ranking given to the Bowen Basin and to the Sydney Basin, and suggests that the Gunnedah Basin also has good potential, in contrast to the earlier report. These assessments rely quite firmly on up-to-date experience with CBM field developments in these three basins. Field development and commercial production experience provides a step-up in grade of evidence of reservoir quality and resource quantity, compared to standard gas-in-place estimates. It also implies improved operational factors, including an expectation of more optimised drilling, stimulation and well completion, improved infrastructure such as pipelines and compression, and improving markets and decreasing costs.

The Southern Bowen Basin has three fields in fairly close proximity, two of which are producing commercial gas in currently modest quantity. They have large gas-in-place at target depths of 500 – 1,000 m, adequate intrinsic permeabilities (1 - 10 md), generally high gas saturation values (>10m^3/t), and normally pressured reservoirs - overpressured in some cases. Methane contents are generally high (~95%).

Extensive experience has been gained in stimulating and completing wells in these reservoirs, using both hydraulic-fracture treatments and cavity completion. These include nitrogen - foam fracture treatments, borate - gel fracs, water fracs, multiple completions into each seam in the coal sequence, cavity completion, and natural cavitation.

With respect to reservoir characterisation, in some instances intensive data is available on open file, detailing *in situ* stresses, fracture gradient, permeability, gas content and composition, and sorption isotherm. In other cases, information is held by the field developers and may become available by negotiation. Comprehensive seismic, geologic and coal quality data have in many cases been summarised and published by government agencies, including data sourced from coal mines operating near to the formation outcrops.

The area is well served by high pressure gas pipelines, and network extension is planned. Continuous sources of separated CO_2 are not known by the authors to be currently available, other than by road tanker delivery. This is available at $A 250/t ($US 150/t) cost of CO_2, delivery from Brisbane. Injection equipment is available at additional cost. A 1,694 MW coal fired power station operating at the adjacent port of Gladstone provides a potential source of flue gas. As an alternative, schemes for generation and compression of artificial flue gas have been considered and assessed as potentially competitive.

The Gunnedah Basin has recently been shown to be much more prospective than had previously been assessed. Target depths of 500 - 900 m and net clean coal thickness of 16 – 30 m are suitable, and very high levels of gas saturation are evident (15 m^3/t), leading to estimates of high levels of gas in place. In addition, high permeabilities (18 - 36 md) have been experienced at depths exceeding ~880 m.

The availability of operational experience in terms of drilling, stimulation and completion match those of the Bowen Basin to the north. However, available reservoir characterisation data will be less detailed compared to the Bowen Basin, based on much smaller number of wells drilled and tested, and fewer open file records.

A new gas pipeline linking Gunnedah to the state network through Dubbo to the south is under construction. Compression facilities would need to be established. Two major coal fired power stations (total 4640 MW) are situated on the boundary with the Sydney Basin, ~200 km to the south.

The ***Southern Coalfield*** of the Sydney Basin has a new field under development at Camden which is exploiting the Illawarra Coal Measures, with net coal thickness of 15 - 25 m at depths of >670 m. The seams have high gas contents (>10 m^3/t). A large amount of geologic, *in situ* stress, and reservoir information is available for these coals, from geomechanics and gas drainage studies in coal mines closer to the coast. This includes reservoir pressures and adsorption isotherms. In general, the mine-based studies have indicated low permeabilities, of the order of 1 md or less at 400 - 500 m depth. However, the recent CBM wells have indicated much higher permeabilities (12 - 36 md) and have been successfully hydraulic-fracture stimulated. Contracts for modest commercial production from this field have been signed.

Drilling, stimulation and well completion expertise are all available. The major industrial port of Port Kembla (coal, steel) lies close to the east, and the Sydney metropolis to the northeast. Major gas pipelines for industrial and domestic supply are present. CO_2 is available on the same basis as for the Bowen Basin, but possibly at lower cost of tanker transport. A 94 MW generator fuelled by mine waste gas operates at the Appin/Tower Colliery, 30 km south of Camden.

Competing Land Uses

The Sydney Basin is known to have large gas-in-place, but is subject to significant land use competition from urban development, national parks and underground coal mining to depths of 600 m. Therefore potential for CO_2 sequestration and ECBM may be relatively restricted compared to the total resource. Nevertheless, Camden and an area further southwest provide a suitable target.

In the Gunnedah Basin, land use competition is low, being mainly rural. Few coal mining operations exist in the basin; these are mainly in the southern margins. However in the long term, the possibility of mining seams at depths to 600 m must be considered.

Competing land uses in the Bowen Basin are farming, coal mining at shallow depths (generally near the margins of the basin), and existing petroleum leaseholds and authorities. Competition is relatively less than in the Sydney Basin.

Political / Regulatory Barriers - Incentives

In Queensland, petroleum exploration and development leases are currently being reformulated by Government authorities with a view to simplifying and facilitating petroleum development. With respect to current leaseholders operating in prospective areas, the promotion of ECBM may provide a suitable key for entry.

In New South Wales, satisfactory negotiation with the state regulatory authorities and with the coal mining industry on the issues of mine safety and sterilisation of minable coal will be a pre-requisite for suitable site access, in the near- to medium-term future.

In the political/economic sphere, Australia's need to meet its greenhouse commitments provides a favourable climate. It is considered that there is potential for collaborative investment in a demonstration project if it can be demonstrated to have high technical and economic feasibility.

Conclusion

On the basis of the information and judgments presented in this assessment, it is recommended that the southern Bowen Basin be considered as the first rank target for a CO_2 sequestration/ECBM demonstration trial in Australia. Assessed against the three groups of criteria under the headings of geological setting, reservoir screening and logistics, it ranks uniformly well against the Gunnedah Basin, for which the data base is more limited, and against the Sydney Basin, for which competing land uses and probably lower coal permeability are limitations.

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CHAPTER 3.
COUNTRY ASSESSMENT - CHINA

3.1 China's Gas Market

China is currently the second largest energy consuming country in the world, after the United States. In 1995, it consumed about 36 quadrillion BTU (quads) of energy (compared to 88 quads in the U.S.). One quad is equivalent to about one trillion cubic feet (Tcf) of dry natural gas. Coal accounted for 73.2%, petroleum 19.5%, natural gas 1.9%, hydroelectric 5.1% and nuclear 0.3% of the primary energy consumption in China. Also in 1995, China became a net importer of energy.

With a rapid growing economy energy demand is projected to grow at 4 - 5% annually through 2015. The US Energy Information Administration (1999) forecasts that by 2015, energy consumption in China will grow to 83 quads. However, domestic energy production would not be able to keep pace and can only reach 72.5 quads in 2015, with the shortfall being met by imports. In terms of production, coal is expected to retain its importance in China's fuel production mix, actually increasing its share to 77.4% from 74.5% in 1995. By 2015 natural gas is expected to grow to about 4.1% of the total energy production. Hydroelectric share is expected to reach 6.2% and nuclear share to 1.6%, as the petroleum share falls to 10.7%. The picture painted is that China will continue to rely heavily on its coal resource to meet its growing energy needs. The challenge for China is that it must develop its natural gas resources.

For many years, natural gas was a relatively minor part of China's energy mix, considered by central planners as too valuable to burn and in short supply. China's natural gas industry also suffered from rationing and price ceilings that bear little resemblance to China's true productive capability and costs. The other impediment for developing China's gas markets was the lack of infrastructure. Traditionally, gas is being viewed as a regional fuel. For example, the pipeline system in the Sichuan Province was developed primarily to deliver gas to local industry users. Consequently, gas consumption and production have remained stagnant at the 500 to 600 billion cubic feet (Bcf) per year level for the past 20 years.

China's Natural Resources Commission estimates that China has 57 quads of proved natural gas reserves, broken out as: Southwest China (mainly Sichuan Province) 19 quads; West China (Tarim and Tu-Ha Basins) 20 quads; South China Sea (mainly Nanhai Basin) 8.5 quads; East China 6.3 quads; and Northeast China 4 quads (Ellsworth and Wang, 1999). China currently produces approximately 653 Bcf/year of natural gas from four established regions, Sichuan Province, Shan-Gan-Ning (Ordos Basin), Xinjiang Uygur autonomous region (Tarim, Chungeer and Caidamu Basins) and Nanhai West in the South China Sea. Sichuan Province is the largest producer with 303 Bcf/year (8,575 Mm^3) of natural gas production and the South China Sea the second largest producer at 113 Bcf/year (3,198 Mm^3). China National Petroleum Corporation (CNPC) forecasts domestic annual production of 1 Tcf (28 Gm^3) by 2000, 2.5 to 2.8 Tcf (71 to 79 Gm^3) by 2010 and 3.5 to 3.8 Tcf (99 to 108 Gm^3) by 2020. This forecast is reasonable and corresponds roughly to the 4.1% gas in the energy mix by 2015. Even at 4.1%, the gas share in China's energy mix is still much below the current world average of around 24%. Production and distribution of gas will be one of China's greatest challenges in coming years (Paik and Lan, 1998).

Signs of awakening of the China's gas industry are now evident. The Ninth 5-year plan proclaims that China will consume 6 - 7 Tcf/year (170 to 198 Gm^3) by 2010. This is a very ambitious goal, requiring the development of a large, stable supply of natural gas. Much of this is driven by the need for China to reduce its carbon emissions from coal consumption and its desire to follow a more market oriented economic policy that allow energy choices to be made in the marketplace. Under this scenario, China must aggressively pursue more gas resources or face imports. One of these options is coalbed methane (CBM).

In March 1996, the State Council of the People's Republic of China approved the formation of China United Coalbed Methane Co. Ltd. (CUCBM). CUCBM was jointly established with the Ministry of Coal Industry (MOCI), the Ministry of Geology and Mineral Resources (MGMR) and CNPC in order to accelerate the development of CBM industry in China. This together with the creation of favourable tax regime for CBM projects and the freedom to negotiate gas price has improved the prospects for early development of CBM industry in China (Du Ming, 1998). The second event, which is more specific to the Ordos Basin and the North Central China areas, is the building of two pipelines, one east to Beijing and one south to Xian from the Shan-Gan-Ning gas field in the Ordos Basin. The ability to build spur lines from the gas producing areas of North Central China to one of these trunk pipeline connections will make it more economical to access markets. The 21st century is an era of gas development in China.

3.2 China's Coal Basins

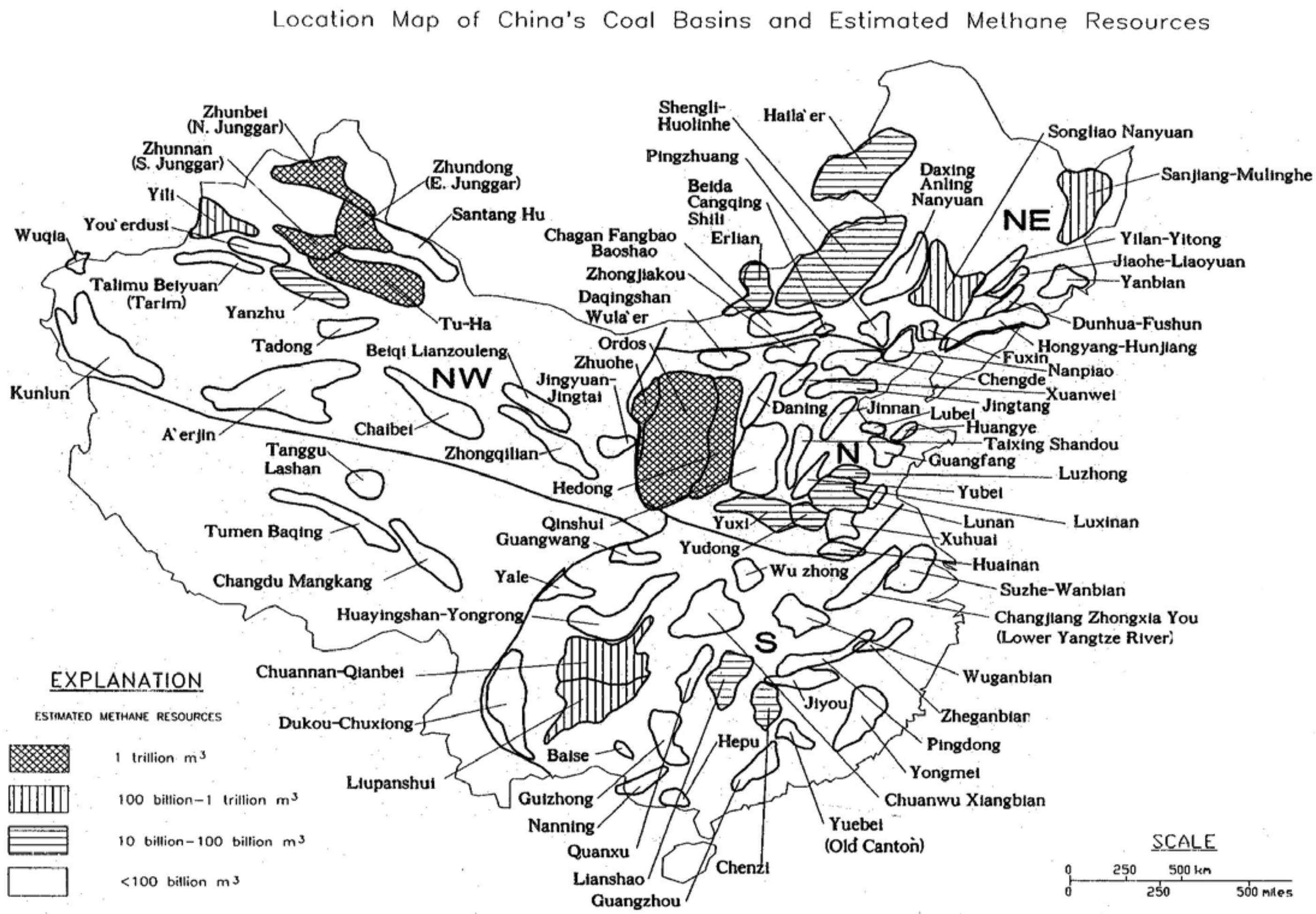
Coal resources of the People's Republic of China are among the world's largest and the extent is evident in the fact that over 1,000 of the country's mines are producing about 1.3 billion tons of coal (International Coal Seam Gas Report, 1997). China's demonstrated coal resources are in the order of 1 trillion tons, with proven reserves accounting for 30% or 296 billion tons.

The coal deposits are distributed throughout China and vary in age, structural complexity and rank. Of the total resources, 75% are bituminous, 12% are anthracite, and 13% are lignite.

The economically important coal seams occur in Permian Carboniferous, Jurassic and Tertiary age sediments.

Northern, northwestern and northeastern China contains 84% of the total in-place reserves. The sedimentary basins are contained within 4 large geographic regions—Northeast, North, South, and Northwest. Each region has unique characteristics that are directly related to their tectonic history. **Figure 3.1** shows the major coal basins in China and their estimated methane resources.

Figure 3.1 China's Coal Basins and Estimated CBM Resources (Modified After U.S. EPA, 1996)



The Northeast Region

The Northeast region contains coal-bearing sediments deposited predominantly during Late Jurassic time, with some deposited during Permo-Carboniferous and Early Tertiary time. The region comprises Jilin and Heilongjiang Provinces, northern Liaoning Province and the eastern part of Inner Mongolia. The tectonics of the Mesozoic age coalfields are relatively complex, due to the impact of the folding and faulting that occurred after the formation of the coal basins. A major subsidence zone, the Cathaysian rift system, developed in northeast China after the Late Mesozoic. Many extensional structures, such as horsts and grabens, formed in the rift system, and the coal-bearing formations are best developed in these fault-defined basins.

Coal seams are generally thick, although the lateral extent within individual coal basins may be relatively small. Coal rank ranges from lignite to high volatile bituminous coal with some occurrence of medium volatile bituminous coals. Late Jurassic coal-bearing sediments are well developed in the eastern part of this region; the Sanjiang-Mulinghe Basin is located in this region. Grabens also formed during rifting events in the southern part of the region; the Songliao Basin contains Late Jurassic coal-bearing sediments.

Most of the coal in this region is bituminous (much of it gassy), although there are some anthracite and lignite coals as well. Late Jurassic and Early Cretaceous lignite deposits occur in Inner Mongolia, mainly in the area north of the Yinshan Mountains. The economic bituminous coal deposits comprise the Tertiary Fushun and Shulan Groups.

Deposits are grouped into 4 main basins, located in the provinces of Heilongjiang, Liaoning, and Jilin.

- The **Sanjiang-Mulinghe** Basin is the most economically important coal basin in Heilongjiang Province, with seams ranging in thickness from 2 to 20 meters. Major Coal Mining Administrations (CMAs) within this basin includes Hegang and Shuangyashan. Coal measures in the Hegang CMA are shallow and gently dipping, and are structurally complicated. These are high volatile bituminous coals, some having coking quality and suitable as a metallurgical coal. The Shuangyashan CMA, also located in Sanjiang-Mulinghe Basin, possesses high quality coals, but is located far from major industrial centers.

- The **Songliao** Basin has an area of 513 square kilometres (km^2). The basin contains the large Tiefa CMA, which has 8 active underground mines, all of which are gassy. Seam depth ranges from 600 to 800 meters. There are 20 coal seams, of which 12 seams are mineable. The basin's major mineable coal seam, No 8, has an average thickness of 2 to 4 meters. Coal rank is high volatile bituminous.

- The **Donhuan-Fushun** Basin is a major coal-producing basin in Liaoning Province. The coal basin has 3 workable Eocene seams whose total thickness ranges from 20 to 134 meters. Structurally, this basin is relatively simple, with laterally continuous high volatile bituminous coal seams that are low in ash and sulphur. The Fushun CMA, located in the Donhuan-Fushun Basin, recovers and uses coalbed methane. In 1993, Fushun CMA had an annual gas drainage of 113.36 million cubic metres (Mm^3).

- The **Hongyang-Hunjiang** Basin is located in Jilin Province. Within this basin, the Tonghua CMA has numerous mineable bituminous coal seams. Some of these Jurassic coal seams are mined for coking coal.

The North Region

The North Region contains the largest quantity of proven coal reserves in the country. It is an important coal-producing region of China, possessing high quality coal and nearby markets. Flat-lying Paleozoic and Mesozoic strata occur in a series of basins comprising 800 square kilometers and extending through Shanxi Province north to Hebei Province and southwest Inner Mongolia. All 12 of the provinces in this region produce coal, making an important contribution to national coal production. Rank of these coals is predominantly bituminous, with occurrences of small amounts of semi-anthracite and anthracite. Coal basins in the northern region are generally linked by rail to the domestic markets and ports from which coal is exported. The rail system to coastal markets has recently been upgraded. The area has been extensively explored, and numerous large underground mines are in operation. Abundant hard coal reserves occur in Inner Mongolia, which lie in remote areas with access to markets via railway.

The North Region consists of predominantly Upper Carboniferous-Permian coal basins, with lesser amounts of coal reserves contained in Lower and Middle Jurassic sediments. Major CMAs and coal basins in this region include Kailuan, Fengfeng, Tonghua, Datong, Jiaozuo, Zibo, Yangquan, Huainan, Huaibei, Yuxi and Hebi. Quality of the Paleozoic coal produced in this region is relatively consistent and classified in high to medium volatile bituminous in rank. In the central part of this region near Taihang Mountain, coal range in rank from low volatile bituminous to anthracite. Key coal basins in the North Region are:

- The economically important coal basin in Hebei Province is **Taixing-Shandou**, with bituminous coals of Permo-Carboniferous age. In this basin, there are up to 21 mineable coal seams, some of which are coking quality, whose maximum thickness is 30 meters. In general, coal measures are gently dipping with some local faulting. Major CMAs in the Taixing-Shandou Basin includes Hebi, Jingxing and Xingtai.

- The **Qinshui** Basin, located in Shanxi Province, is a major coal-producing basin containing Carboniferous, and Permian coals. Major CMAs in the Qinshui Basin include Yangquan, Xishan, Jincheng and Jiaozuo; these CMAs produce bituminous and semi-anthracitic coals. Methane recovery systems are used at the Yangquan CMA, and gas drainage in 1995 averaged 150 Mm^3 per annum.

- The **Daning** Basin, located in northern Shanxi Province, comprises Carboniferous, Permian and Jurassic coals. It contains the largest CMA in China, the Datong CMA. In 1994, the coal mines of Datong CMA produced over 31 million tons of coal, primarily sub-bituminous in rank.

- The **Ordos** Basin is an extensive coal basin, spanning the provinces of Shaanxi, Gansu, Ningxia, and Inner Mongolia. It contains Carboniferous, Permian and Jurassic coals. Major CMAs contained within the Ordos Basin includes Tongchuan, Wuda, and Cuijiagou, which produce sub-bituminous and bituminous coals.

- Most of the coal seams in Henan Province are relatively deep and were deposited in Permo-Carboniferous time. The **Yuxi** Basin contains the Pingdingshan and Yima CMAs.

- The **Xuhuai** Basin, located in northern Anhui Province, contains substantial anthracite and bituminous deposits of coking coal. It is a large basin, covering 4,000 square kilometers and containing 12 coal mines, 10 of which are considered highly gassy mines. Seam depth ranges from 400 to 1,000 meters, with 13 to 46 seams, 4 to 13 of which are mineable in various parts of the basin. The basin contains the large Huaibei CMA. At these mines, seam thickness ranges from 1 to 19 meters. The coal-bearing strata are predominately steeply dipping, but free of intense structural deformation.

- The **Huainan** Basin is an important coal basin in southern Anhui and Jiangsu Provinces, covering an area of 2,500 to 3,000 square kilometers. Depth of the coal seams is generally less than 1,000 meters, with a maximum depth of 1,700 meters. There are 10 to 18 seams considered mineable; 4 to 5 major seams are 2 to 6 meters thick. Permo-Carboniferous coal seams range in rank from low to high volatile bituminous, much of which becomes coking quality with depth. The Huainan Basin is linked by railroad to the ports of Suzhou and Shanghai.

The South Region

The South Region comprises Paleozoic and Mesozoic bituminous and anthracite coals, of Paleozoic and Mesozoic age, with less important coal seams deposited during the Late Tertiary. Most of the coal deposits in the region were deposited in the Permian and Late Triassic-Early Jurassic. Important deposits of extractable coal deposits in the eastern part of this region are limited to complex tectonics and thinner seams. These deposits are scattered throughout the provinces of Hubei, Hunan, Guangxi, Guangdong, Fujian, Zhejiang, Jiangxi, and South Anhui. Numerous medium and small coal mines are currently operating in this area.

Permian coal deposits in Guizhou, Sichuan, and Yunnan Provinces are large, accounting for about 75% of the total coal resources in the South Region. Although the southwestern part of this region lacks the infrastructure of the North Region, the government is committed to aggressively developing these coal resources. Some of the key coal basins in the South Region are:

- The **Chuannon-Qianbei** Basin is located in Sichuan and Guizhou Provinces. It contains thick, bituminous coals of coking quality. There are also semi-anthracite and lignite deposits in Sichuan Province. Major CMAs in this basin include Songzao, Furong, Nantong, and Zhongliangshan. The Songzao CMA, between Sichuan and Guizhou Province, recovers and uses coalbed methane from underground methane drainage systems. In 1992, Songzao drained 67 Mm^3.

- **Huayingshan-Yongrong** Basin is located in northern Sichuan Province. The basin contains 2 large CMAs with gassy mines, the Yongrong and Huayingshan CMAs.

- Guizhou Province contains large coal reserves, which have only been recently explored. They consist mainly of Permian bituminous and anthracite deposits. The **Liapanshui** coal basin is the most extensively developed coal basin in the province. The Panjiang, Shuicheng, and Luizhi CMAs are located in this basin.

- There are 6 gassy mines in Yunnan Province; however, none of these are part of large, state-run CMAs. They are the Yipinglang, Yangchang, Laibin, Tianba, Houshou, and Enhong mines. Neither coal gas content nor specific emissions data are available for these mines.

The Northwest Region

The Northwest Region is geologically similar to the North region, containing large resources of mainly Jurassic and some Permo-Carboniferous deposits of bituminous coal. The deposits are located in the provinces of Xinjiang, Gansu, and Qinghai. Despite large reserves, coal production is low due to the lack of infrastructure and the region's distance from heavy industry and population centres.

Xinjiang Province, located in extreme northwest China, contains the largest estimated coal resources of any province. Jurassic coal deposits range from lignite to bituminous in rank, and are mostly high volatile bituminous. Three large basins, the **Junggar, Tu-Ha**, and **Yili** Basins, contain numerous thick coal seams, ranging to a maximum thickness of 200 meters. Although current production in this region is limited, it is an area with a great potential for future coal development.

3.3 Coalbed Methane Resources

Contained within enormous coal resources in China is an equally enormous quantity of gas. Estimate range from 30 to 35 trillion cubic meters (1,071 to 1,250 Tcf). The vast potential for CBM development is apparent when looking at the extent of mine gas emissions, drainage, utilization and coal characteristics. More than 97% of active mines are underground operations, and about one-half are classified as gassy. A small volume of coal-mining related methane is already recovered from in-mine borehole drainage and gob drilling.

While CBM resource concentration is favourable, locating higher permeability is challenging. Well testing in eastern China indicates restricted permeability, generally well below 1.0 millidarcy (md). However, most tests took place in high rank and structurally complex coal-mining areas, where coal mine degasification was a primary objective.

Chinese coal basins are structurally and geologically more complex than the commercial U.S. coalbed methane areas. Faults, some active, compartmentalize the coal reservoirs into isolated blocks that would be difficult to develop. In addition, erosion of the coal section, and reburial during Quaternary time has affected gas saturation in East China coal basins.

Similar to the coal resources, the coal seam gas resource is widely distributed and the reported resource potential estimate and ranking of the fields vary. Nomenclature also varies according to how the basin, field and area names have been translated. The evaluation of the areas most prospective for coalbed methane development cite the eastern Ordos Basin (Shanxi and Henan Provinces), Songliao and Donhuan-Fushun Basins (Liaoning and Hebei Provinces), Huaibei and Huainan basins or areas (Anhui Province) and Chuannon-Qianbei Basin (Sichuan and Guizhou Provinces). Most estimators agree that two-thirds of the country's total resources are concentrated in the eastern and central provinces. The primary target area contains coal seams at least 2 meters thick at depths of 300 to 1,000 meters, gas content of at least 9 cc/g, permeability value of at least 1 md and location within areas known for gassy mines and regional industrial development. It should also be noted that about 66% of the CBM resources are deposited deeper than 1,000 meters.

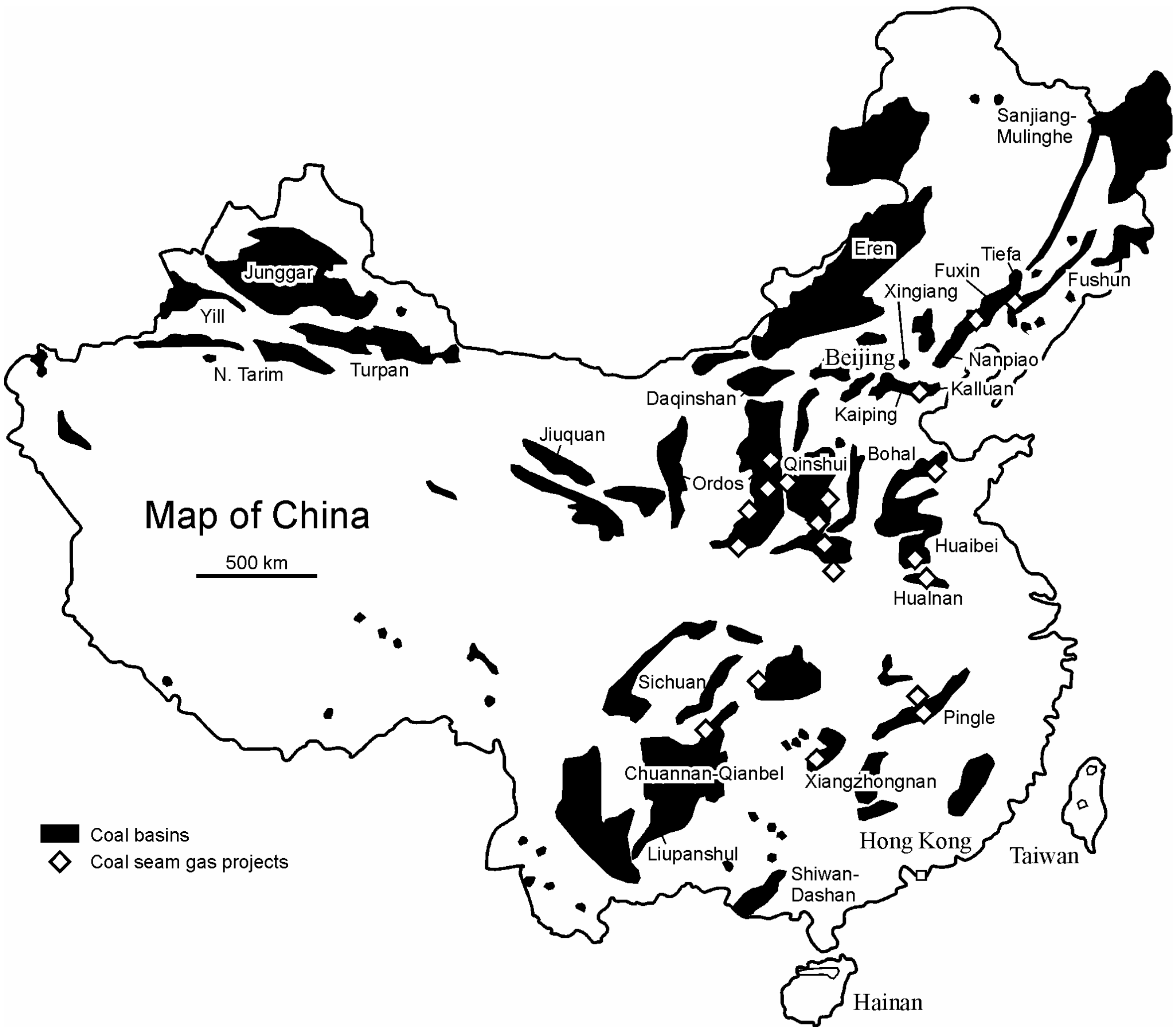
Coal seams gas resources of selected basins (Zhang et al., 1995)

Basin	Province	Resources	
		Gm^3 (10^9 m^3)	Tcf
North and Northeast			
Ordos	Shaanxi, Ninqxi	11,324	400
Qinshui, Daning	Shanxi	6,850	245
Sanjiang Mulinghe	Heilongjiang	401	14
Huainan-Huaibei	Anhui, Jiangsu	400	14
Southern China			
Liupanshui	Quizhon, Yunnan	1,334	47
Chuannan-Quianbei	Yunnan	1,121	40
Northwest China			
Hauin-Turpau	Xinjiang	4,647	164
Junggar	Xinjiang	2,997	106
Yili	Xinjiang	925	33

3.4 Basin Assessment

Even though the Chinese coal mining industry was experimenting with CBM in the 70s and 80s, the main activities in CBM exploration started in the 1990s. Chinese and foreign companies evaluated a number of diverse areas and helped to define the high-potential plays, although none of these projects obtained commercial status. **Figure 3.2** is a map showing the general locations of present and prospective coalbed methane development in the principal coal-bearing areas of China. In recent years, approximately 150 CBM wells were drilled in China.

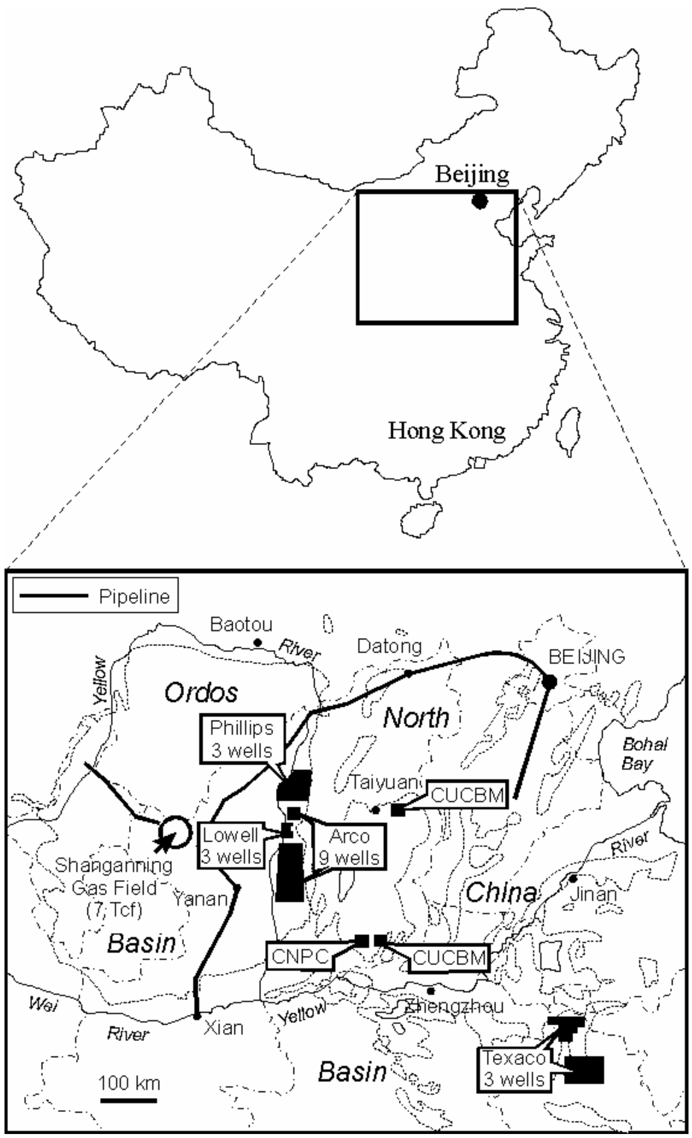
Figure 3.2 China's Coal Basins and CBM Prospects (Modified After the International Coal Seam Gas Report, 1997)



Most of the CBM activities through cooperation with foreign companies have been in the North region, primarily in the Ordos and Huaibei Basins (Stevens, 1999). The nine-coalbed methane blocks that have been approved for foreign cooperation are in the areas of Huainan and Huaibei of Anhui Province, eastern areas of the Taihang Mountains in Northern China, and Linxing, San Jiao, San Jiao Bei, Shilou and Liulin areas in Shanxi Province and Fengcheng of Jiangxi Province. To date a total of 7 Production Sharing Contracts (PSCs) for the cooperative exploration of coalbed methane were signed between CUCBM and 5 foreign companies including four US companies (Texaco, Phillips, Arco, Saba Petroleum) and one Australian company (Lowell Petroleum Company).

Texaco: Huaibei Project, Anhui Province (Huaibei basin)
Phillips: Linxing Project, Shanxi Province (Hedong Prospect in Ordos basin)

Figure 3.3 Coalbed Methane Exploration in China (Modified After Stevens, 1999)



ARCO: San Jiao, San Jiao Bei, Shilou projects, Shanxi Province (Hedong Prospect in Ordos Basin)
Saba: Fengcheng Project, Jiangxi Province
Lowell: Liulin Project, Shanxi Province (Hedong Prospect in Ordos Basin)

Chinese operators during 1990-1996 included Shenyaing (Municipal) Gas Company, the Ministry of Coal Industry (MOCI), Ministry of Geology and Mineral Resources (MGMR), and China National Petroleum Corporation (CNPC). The largest project was MGMR's six well, fraced production pilot at Liulin (Shanxi Province) in eastern Ordos Basin, which achieved peak gas rates of 7,000 m^3/d from a shallow coal seam (<350 m).

Currently, CNPC and CUCBM are testing in several areas **(see Figure 3.3)**, applying modern CBM exploration and production technologies. The south Qinshui Basin has been designated as "self-financing" region and hence, none of the blocks has been offered for foreign cooperation.

A total of 80 test wells to date (pre-1996) have been attempted by the following 3 organizations in China:

- Ministry of Coal Industry - 45 wells in Shenbei, Tangshan, Jiaozhou, Fushun, Panzhuang, Yangquan, Liwangmiao, Xinggong and Wudongguo;

- Ministry of Geology and Mineral Resources - 13 wells in Anyang, Liulin, Huainan and Huaibei;

- China National Petroleum Corp. - 6 wells in Licheng, Dacheng, Oulitouzi, Lengshujiang. Fengcheng and Qinshui.

Results from the 64 test wells were mostly for research and development. Infrastructure was not available in most cases; thus results met minimum guidelines for CBM production.

In this assessment, we will focus only on three basins in the North region – Ordos, Qinshui and Huaibei. We will capture the rest under other basins.

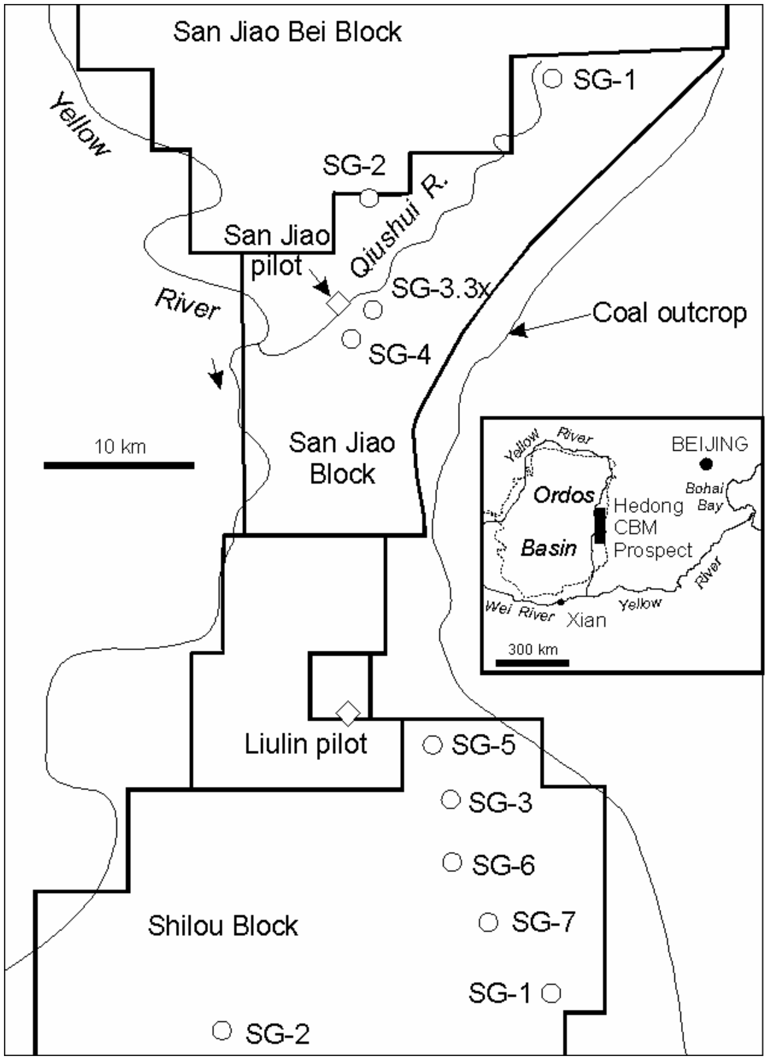
3.4.1 Ordos Basin

The Ordos Basin is an asymmetric cratonic basin covering an area of about 250,000 km^2. It consists of a thrusted western margin and a gently dipping eastern limb. The basin is floored by metamorphic basement and contains 4 to 18 kilometres of overlying sediment. Conventional oil and gas are produced from about 25 fields in the basin, including the Shan-Gan-Ning gas field, which contains about 7 Tcf of gas in place.

Hedong CBM Prospect

The Hedong Prospect is located on the eastern flank of the Ordos Basin between coal outcrops and the Yellow River. It is divided into four blocks – San Jiao Bei, San Jiao, Liulin and Shilou **(Figure 3.4).** Previous drilling shows good cumulative coal thickness (8 – 20 m), adequate gas content (12 –18 m^3/t) and potentially high permeability (<1 to 90 md). The gas in place volume for potentially productive coals at 250 to 1,250 m-depth may exceed 10 Tcf. The targeted coals are of the Permo-Carboniferous age and consist of 10 seams distributed over a 150 to 200 m interval. Recovered coals and rock cores show that the deeper coals are thicker, more continuous and of higher quality than the shallower coals. Interbedded sandstones and limestones have low matrix permeability but fractured limestones may contribute significant volumes of water in some areas. Coal maturity increased southward from high volatile A bituminous to semi-anthracite rank. Ash content ranges from 5 to 25% and is dominated by dispersed and layered clay.

Figure 3.4 Hedong CBM Prospect (Modified After Jenkins et al. 1999)



ARCO, Texaco and CUCBM are currently assessing the coalbed potential of the Hedong Coal Prospect (Jenkins et al., 1999). In 1992 Enron signed an agreement with the Chinese Government to assess the CBM potential of the Hedong area and drilled 2 core holes in early 1993 which showed favourable coal thickness and gas content. That same year the Hedong Prospect was chosen as the best potential CBM area in China. This led to the establishment of the Liulin Pilot Project, a co-operative project between the Chinese Government and the United Nations to demonstrate the CBM potential in China. The project extending from 1993 to 1996 include seven wells that averaged 1,000 to 3,000 m^3/d of production, with a peak of 7,000 m^3/d in one well.

Coincident with the Liulin pilot, Enron drilled seven additional wells from late 1993 to 1995 to evaluate reservoir characteristics and production potential of the Shanxi and Taiyuan Formation coal reservoirs in the Hedong Prospect. The results were very favourable. They encountered laterally continuous coal (8 – 20 m cumulative thickness), with good gas content (12 – 18 m^3/t) and a large range of well test permeability (<1 to 90 md). Several wells were cavitated and placed on production resulting in water rates of 50 to 190 m^3/day.

ARCO joined Enron as a partner in early 1997 to continue the appraisal work. ARCO purchased Enron's interest in mid-1997 and signed a PSC with CUCBM in mid 1998. ARCO drilled four appraisal wells in the Shilou block in late 1997. Texaco joined the project in 1998 and participated in four pilot wells recently drilled in the San Jiao block. The appraisal wells were completed in the autumn of 1998 and the pilot wells would be completed in the spring of 1999.

Huawell Coalbed Methane Company was granted a concession of 218 km^2 in the Liulin area. The site is an area between the Shilou block to the south and the San Jiao block to the north. Huawell Coalbed Methane Company was a joint venture formed by the North China Bureau of Petroleum Geology and Lowell Petroleum Pty. Ltd. of Australia. In May 1995, it drilled the first well at a site near the western boundary of the permit. Well data showed excellent gas saturation and permeability and was significantly over-pressured (Anonymous, 1999). A second well was drilled nearby with similar results. The third and final well of the first exploration phase of the Liulin contract was drilled in October 1995 at a site near the eastern boundary of the permit. This well also intersected the target seams with excellent gas saturation and permeability but these seams were under-pressured on account of a thick cover of younger Quaternary sediments. The results of the three test wells were reported in International Coal Seam Gas Report, 1997 as follows:

Net coal thickness	9 to 13 meters
Coal depths	300 to 1,000 meters
Vitrinite reflectance	1.34 to 1.59%
Permeability	0.1 to 12 md
Gas Contents	
Shanxi # 4	425 scf/ton
Shanxi #5	340 scf/ton
Taiyuan # 8	475 scf/ton
Taiyuan # 9	525 scf/ton
Taiyuan # 10	490 scf/ton

Gas production rates in the area are between 18 to 106 Mcfd with small amounts of water. Note that vitrinite reflectance is a measure of how bright polished vitrinite is; reflectance increases with coal rank. For example, vitrinite reflectance for a high volatile A bitumen on coal would be about 1%.

Exploration in the southern Ordos was less encouraging. Lowell drilled two wells in 1996 which intersected the target Jurassic coals with the requisite thickness and permeability, however, measured gas contents were low for both wells. Since reliable isotherm data indicated an adsorptive capacity for the coal of about 15 m^3/t, it would appear that a period of uplift and erosion has led to a de-gassing of the coals on a regional scale.

Phillips Petroleum is testing the Hedong CBM Contract area just north of ARCO's lease in the Linxing area of Ordos Basin. Following the acquisition of high-frequency seismic data during 1997, Phillips has tested gas content and permeability at three wells within its 3,120 km^2 block. Coal rank and gas content are somewhat lower than in the southern Ordos, but the coal reservoirs here are thicker. Phillips' block is located about 100 km south of the newly completed 91 cm (36") Ordos-Beijing natural gas pipeline, and 120 km west of Taiyuan, a major industrial city. Phillips plan to drill and complete several additional production wells during 1999.

Amoco Orient Petroleum Company signed a US$ 10 million joint venture agreement with Ministry of Coal Industry and China National Petroleum Corp. in late 1994. The areas where Amoco evaluated the potential for CBM included the Shanxi and Shaanxi Provinces of the Ordos Basin. Gas contents were deemed encouraging for local commercial development. When no local development could be agreed to, Amoco evaluated the possibility of expansion of infrastructure. It still showed economic potential, but Amoco still could not complete a satisfactory joint venture agreement with the Chinese.

In summary, typical reservoir parameters that may be expected from the Hedong Prospect may be as follows:

Table 3.1: Typical Reservoirs Parameters for the Hedong Prospect

Individual Seam Thickness	1 – 9 m
Cumulative Seam Thickness	N/A
Completable Thickness/Depth	25/1,000 m
Permeability	1 – 40 md
Coal Rank	Medium volatile bituminous,
Ash Content	N/A
Moisture Content	N/A
Gas Content	Estimated >12 m^3/t
Gas Saturation	Saturated
Cleating	Good
Mineralization	Not known

3.4.2 Qinshui Basin

With an area of 5,560 km^2 on the slope of Qinshui basin, the area is estimated to have reserves of 980 Gm^3 of coalbed methane.

Jincheng Area, South Qinshui Basin

The Jincheng field occupies an area of 406 km^2. The coalbed methane reserve is estimated at 99 Gm^3 at a depth of 300 to 1,000 m. CBM concentration is 244 Mm^3/km^2. The coal seams of interest mainly occur in the lower Permian Shanxi Formation and the upper Carboniferous Taiyuan Formation with structure dipping towards the northwest on coal occurring at depth from 300 to 1,000 m (Li et al., 1999). Anthracite occupies a great part of the region and meager coal lies in the northwest part. Total coal thickness in the Jincheng area varies from 10 to 15 m and is continuous laterally. Seam 3 and Seam 15 are the main target coalbed reservoirs. Seam 3 occurs in the lower Permian Shanxi Formation and stabilises in most of the area with a thickness of 4 to 7 m. It is mostly developed with a thickness of over 6 m around Fanhuang Village and Panzhuang Village and pinches out to the west and east. Hence, Seam 3 is a thick seam with consistent deposition throughout the whole area. Seam 15 occurs in the Upper Carboniferous Taiyuan Formation and is present in most of the area with a thickness of 1 to 6 m. It is mostly developed with a thickness over 3 m north of Panzhuang Village and pinches out to the north and west. Gas content in Seam 3 averages about 15 m^3/t. Injection/fall-off tests show that Seam 3 and 15 have permeability ranging from 0.1 to 3.6 md. Jinshi 1 Well has produced for 3 months. From the dynamic data collected, the simulated permeability of face cleats and edge cleat simulated based on production is 7 and 5.9 md respectively which is an order of magnitude larger than derived from the transient testing. Formation pressure from transient testing in Jinshi 1 Well is 4.8 MPa at a depth of 524 m. A stable production of 2,700 m^3/day was achieved under 0.23 MPa of casing pressure.

The International Methane Company Ltd. and its partner Jincheng Coal Mining Bureau have a 35,750-acre concession to explore and develop CBM in the Panzhuang area. The primary target is a 20-foot seam in the Shanxi Formation (Permian) with additional targets in the underlying Taiyuan Formation (Carboniferous). Results from tests are as follows:

Depth	425 meters
Number of seams	21
Net thickness	11 to 18 meters
Gas contents	970 scf/ton (maximum) (31 m^3/t)
Production tests	
PZ # 2 well	
Gas flow rate	106 to 230 Mcfd (3000 to 6511 m^3/d)
Water flow rate	50 to 250 barrels/day (8.0 to 40 m^3/d)

China United Coalbed Methane Co. Ltd. operations group has drilled 25 wells in Qinshui Basin in Shanxi Province of which 16 wells are in the South Qinshui Basin. The coal is a high-rank anthracite at Jincheng. Stable daily output of CBM were observed from the pilot wells at the Anze and Tunliu blocks of Qinshui Basin, with a high rate of 16,300 m^3/day at one well. On the basis of the pilot data, the area contains 100 Gm^3 of CBM within the 550-km^2 block. The properties of this CBM field are characterized by high coal rank, thick and stable coal seams distribution, moderate buried depth, relatively simple structure, good sealing conditions, high gas content and high permeability. This area is in the vicinity of large consumers with large natural gas potential. CNPC is also testing a 5-spot CBM pilot in the high-rank Jincheng mining areas of southern Qinshui basin, close to CUCBM's pilot.

Table 3.2: Typical Reservoirs Parameters for the South Qinshui

Individual Seam Thickness	1 – 9 m
Cumulative Seam Thickness	8 – 16 m
Completable Thickness/Depth	8 – 10 m/500 m
Permeability	0.1 – 3.6 md
Coal Rank	High volatile bituminous to anthracite, Vitrinite Reflectance (Vro) 0.7-3.5%
Ash Content	10 – 15%
Moisture Content	0.5-2.5%
Gas Content	12 – 26 m^3/t
Gas Saturation	Saturated 70 – 90%
Cleating	Good
Mineralization	Not known

Yangquan-Yushe, North Qinshui Basin

BHP Petroleum had established a joint venture with both Huaxian Development and Huatai New Technology Development to evaluate first and then develop a CBM project on 386 square miles in the Yangquan-Yushe mining area, east of Taiyuan and in the northern part of the Qinshui Basin. The 200-metre thick Permo-Carboniferous coal-bearing sequence contains 17 seams. The 3 main productive seams average 25 feet thick at depths between 1,300 to 1,900 feet. Recorded gas contents vary from 440 to 575 scf/ton. No other data is currently availability.

Projects outside of Qinshui Basin, in Henan Province

These projects are located to the south of Qinshui Basin, but may be significant in the development of the whole area.

Enron's second project, in western Henan is near the city of Pingdingshan, about 120-km southwest of Zhengzhou. This field includes 14 mines and is bound by northwest trending faults that are separated by a series of folds. The thick II-1 seam in the Lower Shanxi formation is the most developed seam in the area. Tests results indicate very good gas content (maximum 500 scf/ton or 16 m^3/t) and permeability (1-10 md, based on an injection fall-off test). The following is a brief outline the results in this area:

Number of coal seams	74
Average thickness of best seam	4 m
Rank	high to medium-volatile bituminous
Vitrinite reflectance	0.85 to 1.81 %
Coal cleat spacing:	
Face	18-21/5cm
Butt	3-5/5cm
Porosity (saturated)	2 to 10 %
Average Permeability	1.0 md
Average gas content	375 scf/ton (12 m^3/t)
Gas resource to 1200 meters	107 Bcf (3,028 Mm^3)

International Methane Company's second project, a 220,000-acre play in Henan is called Xing-Gong, a joint venture with Zhengzhou Natural Gas Company. Target was a 11-meter thick seam in the Shanxi Formation. Two wells have been drilled with following results:

Depth	460 meters
Net thickness	10 meters
Gas contents	718 scf/ton (23 m^3/t)
Production tests	
Xin # 1 well	
Gas flow rate	247 to 275 Mcfd (6,993 to 7,785 m^3/d)
Water flow rate	150 to 300 barrels/day (24 to 48 m^3/d)

This project is now in the hands of Texaco and they are planning a full-scale development project.

3.4.3 Huaibei Basin

The coal basins of the Huaibei region are part of the extensive Central China-Korea tectonic platform encompassing much of central and eastern China, Bohai Bay, part of the Yellow Sea and the Korean Peninsula. The Huaibei coal region actually comprises four individual coal-bearing basins (Nanping, Sunan and Xiaoxi synclines and Sudong), that are separated by major uplifts and associated faults. Currently, because of better data control, the Nanping and Sunan synclines in southern Huaibei are the two primary basins of interest.

The Huaibei coal region has complex post-depositional history. Beginning in the Late Jurassic, an east-west directed Yanshanian compression resulted in extensive folding and thrust faulting along the basin margins. All synclines at Huaibei now share an asymmetrical structural geometry where the western flanks tend to be only moderately deformed and dipping east into the basin at 10 to 30 degrees, while the eastern flanks are strongly folded and typically overridden by thrust faulting. During middle Tertiary time, transgressional extension throughout eastern China resulted in renewed uplift and significant erosion of the exposed Paleozoic strata. Following this extended period of erosion, the region once again subsided during the Quaternary, resulting in the deposition of a thick blanket of unconsolidated sand directly overlying the Paleozoic strata. Whether this significant period of uplift, erosion and cooling resulted in extensive gas loss and regional gas undersaturation in Huaibei is currently unknown.

Texaco Huaibei block

Texaco was the first to sign a CBM production contract with CUCBM, commencing on March 1, 1998. Later that year, Texaco drilled three wells within their 2663 km^2 Huaibei block in northern Anhui Province (Derickson et al., 1998). The age of the coal deposit is Late Carboniferous to Early Permian. The principal coal seams at Huaibei (seams 7, 8 and 10) average 10 to 15 m (32 to 49 ft) thick, with gas contents of about 12 m^3/t (380 scf/ton) at a depth of 610 m (2,000 ft). Data control is relatively good, with hundreds of coal exploration coreholes drilled throughout the area. Given its East China setting, geologic conditions are fairly complex, but potential gas markets in this industrial area are attractive. During 1999, Texaco plans to hydraulically stimulate the wells and put them on long-term production. Typical reservoir parameters are shown in **Table 3.3.**

Table 3.3: Typical Reservoirs Parameters for the Texaco Huaibei Block

Individual Seam Thickness	N/A
Cumulative Seam Thickness	Net 10-15 m, coal seams 7, 8 and 10
Completable Thickness/Depth	10/600 m
Permeability	N/A
Coal Rank	High volatile A bituminous, Vitrinite Reflectance (Vro) 1.0%
Ash Content	Medium (15%);
Moisture Content	Not known
Gas Content	10-14 m^3/t
Gas Saturation	Undersaturation is common occurrence
Cleating	Well cleated
Mineralization	Not known

3.4.4 Other Basins

Fengcheng Coalfields, Jiangxi Province

CUCBM and Saba Petroleum, of the U.S., have signed a contract to explore coalbed methane resources in Jiangxi Province. The partners will explore an area covering 1,540 km^2 at the Fengcheng coalfield. The methane reserves of the area are estimated at 37.1 Gm^3.

Tiefa, Shenbei and Hongyang fields, Liaoning Province

Shenyang General Gas Corporation established a technical service contract with Advanced Resources International to evaluate 3 coalfields. A series of test wells and coreholes were drilled in Tiefa, Shenbei, and in the Hongyang field, at the north end of Liaoning Province. The tests targeted coals of different age, rank and structural setting. Results from core data and pressure, transient tests, indicated the Tiefa field was the best area. It was also closer to the market.

The Shenbei area was selected for hydraulic fracturing and production testing. Stimulation on well # 5 was a mix of sand and water. Results were a maximum gas flow rate of 64 Mcfd (1812 m^3/d) and declining to 5.3 Mcfd (150 m^3/d) after 18 months.

Kailuan field, Hebei Province

A second project was conducted by Advanced International with Kailuan Coal Mining Administration at Tangshan mine, located 100 miles east of Beijing. Two test wells targeted high-volatile A bituminous (Permo-Carboniferous) coals. Results indicated lower than the norm in gas contents and significantly under-pressured reservoirs.

Fuxin Field, Liaoning Province

CBM Energy Associates entered into a joint venture agreement with Fuxin Municipal Planning Commission to drill a test well in the Wangjiaying mine in Fuxin field, Liaoning. It began drilling in early 1994. Operations were suspended in late 1994 due to drilling problems (International Coal Seam Gas Report, 1997).

3.5 CO_2 Sources

The basin assessment suggests that the Ordos Basin and the Qinshui Basin are the two better basins among the perspective basins. However, an adequate supply of CO_2 is a pre-requisite for the CO_2 – ECBM process. From this perspective, the south Qinshui Basin is clearly a better choice. The south Qinshui Basin is close to the cities of Changzhi and Jincheng, two large heavy industrial cities in Central China. In this vicinity are the Yangcheng Power Plant (the largest in Shanxi Province); Changzhi Iron and Steel Plant; Yanaquan Power Plant and the fertilizer and urea manufacturing complex in Changzhi and Jincheng. These plants will be able to supply the CO_2 (via their waste flue gas stream) necessary for the commercial development of the CO_2 – ECBM process in the area. These plants can also be developed as large users of the coalbed methane produced. On the other hand, the east Ordos Basin is in a much more remote area to the west, away from the industrial area. CO_2 supply will be problematic for the Ordos Basin.

3.6 Conclusions

The assessment indicated that the Hedong Prospect in the eastern flank of the Ordos Basin and the south Qinshui area near the CUCBM pilot are clearly the two better sites for implementing the CO_2-ECBM pilot. Both fields are fairly well explored, one area mostly with foreign companies and the other by CUCBM and CNPC. The following are the relative merits between the two sites:

- The east Ordos site has better production potential in terms of higher permeability
- The south Qinshui site has simpler geology
- In terms of downstream utilization market, the south Qinshui area is adjacent to the most developed industrial regions in China, but the Ordos site has the potential of connecting to the trunk pipeline moving the gas to Beijing
- In terms of CO_2 sources, south Qinshui is much better positioned.

We believe the south Qinshui site is a better site for the CO_2 – ECBM pilot. However, both sites are recommended for further ranking.

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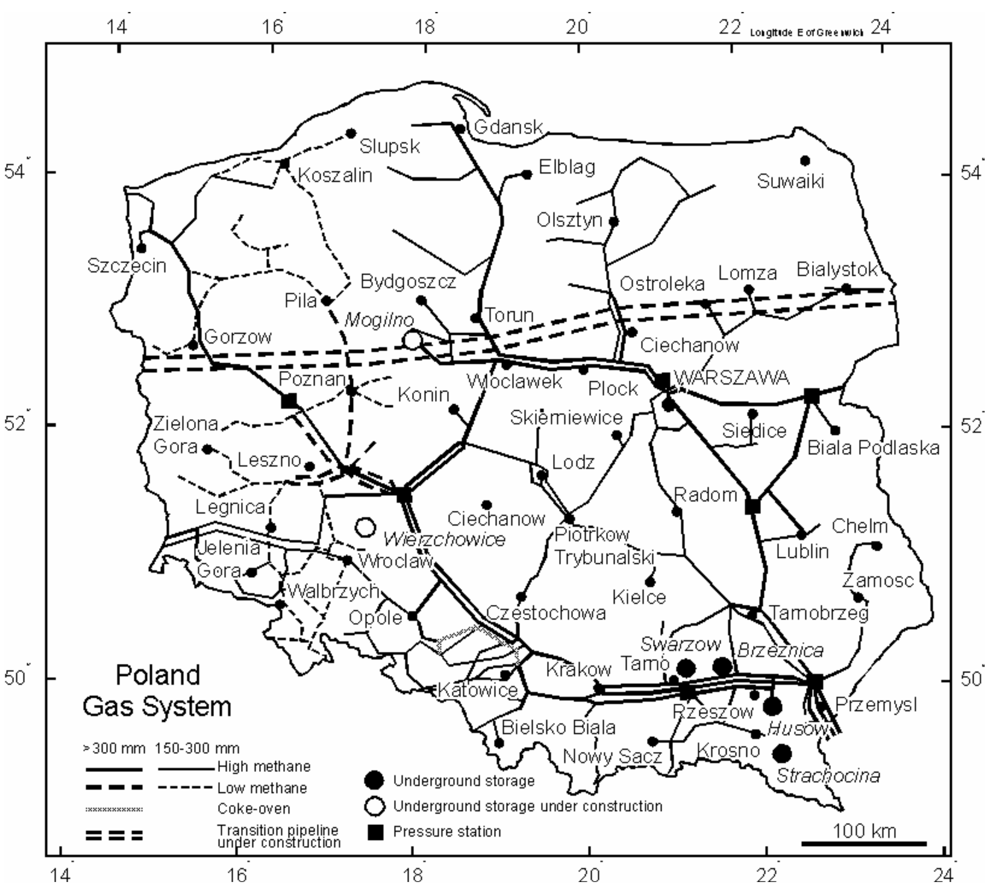
CHAPTER 4.
COUNTRY ASSESSMENT - POLAND

4.1 Poland's Gas Market

The Polish energy sector is based mainly on coal – both hard coal (mostly bituminous) and soft coal (lignite). Industries use primarily hard coal while lignite is used only for electric power generation. In 1996, Poland produced about 138 million tonnes (Mt) of hard coal. Domestic consumption was approximately 109 Mt with the balance being exported as steam and coke coals. Natural gas's share in the energy mix was about 10% or about 10.9 billion cubic meters (Gm^3). Of these, the industry sector consumed 5.4 Gm^3, while the residential sector consumed the remaining 5.5 Gm^3. Poland's natural gas production was relatively small, at 3.6 Gm^3. A significant amount, 7.3 Gm^3 was imported, mostly from Russia. A map showing the major cities and the gas transmission system in Poland is shown in **Figure 4.1**.

Figure 4.1 Poland's Major Cities and Gas Transmission Lines



The structure of the primary energy consumption in Poland in 1996 was as follows:

Hard coal	108.6	Mt
Lignite	62.7	Mt
Natural gas	10.9	Gm^3
Oil	14.7	Mt

Poland produced far less natural gas than it consumed. Estimated natural gas resources amount to 149 Gm^3. Most domestic natural gas was produced in the western part of the country and has a low heating value. Because domestic gas production and reserves were limited, Poland imported natural gas from its neighbor, Russia. The state Polish Oil and Gas Company has a monopoly on the importation, transmission, storage and distribution of natural gas.

Poland became a member of the Organization for Economic Cooperation and Development (OECD) in 1996. It is also pursuing membership in the European Union (EU). Complications for full membership include: EU demands that Poland liquidate its "special economic zones"; achieve a faster pace of privatization; and improve environmental conditions, a situation exacerbated by Poland's heavy reliance on coal. Increased consumption of natural gas, as an alternative to coal is considered a key component of Poland's plan to meet the stricter regulations. Gas consumption although currently not increasing as quickly as expected, remains projected to double to about 20 Gm^3 by 2010.

Efforts to diversify natural gas supply sources are underway. Existing infrastructure cannot support significant imports from non-Russia sources, for example Norway. Norway currently plans to pipe gas through Germany. A pipeline under the Baltic Sea is also under consideration. In addition to the non-Russian projects, a pipeline project is currently underway to connect Russian gas from Yumal (West Siberia) to Europe through Poland. The Polish section of the gas pipeline is now complete. Extension of the pipeline to Germany is behind schedule, as demand in Europe is not growing as quickly as expected. It is under this environment – some positive (higher environmental standards, faster pace of privatization, gas infrastructure development) and some negative (cheap import competition, a high taxation regime) that the coalbed methane supply must fit itself in.

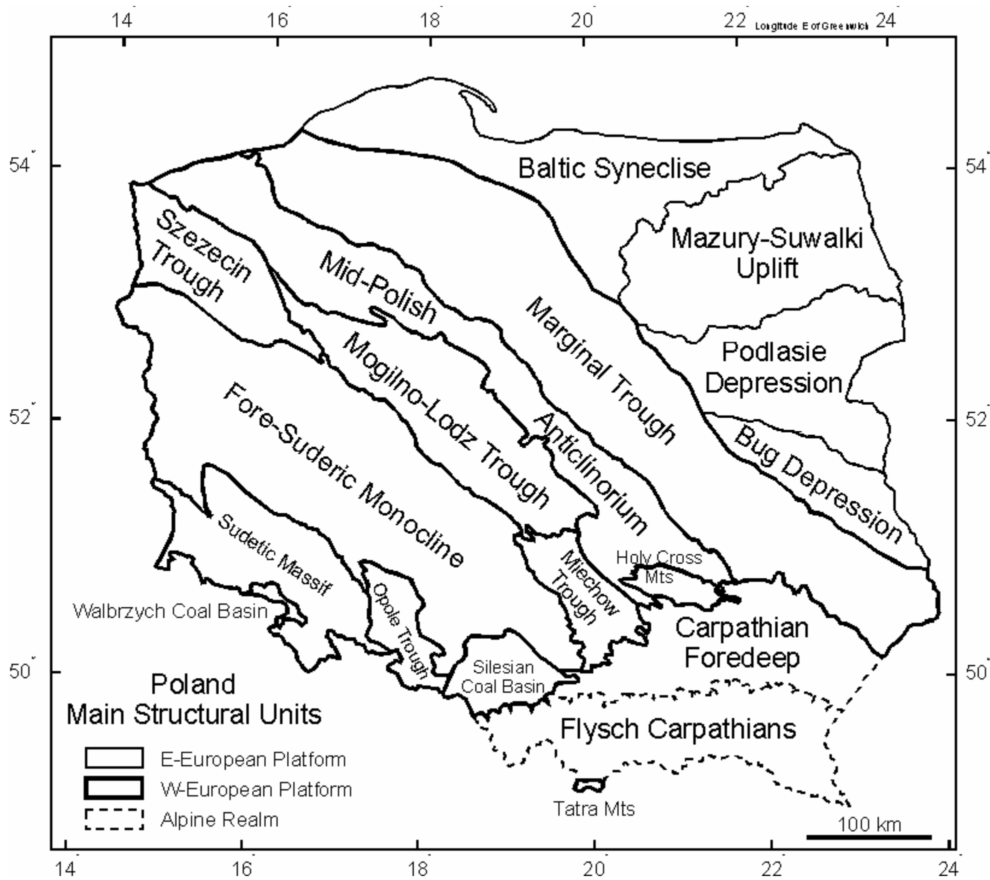
4.2 Geological Setting

The coal deposits in Poland occur in basins related to the evolution of Variscan orogenic belts and adjoining platform areas. The main structural units are shown in **Figure 4.2**. The evolution of the orogen resulted in the formation of three types of structural molasse basins, all of Carboniferous age, predominately coal-bearing, namely:

- the intradeep basin, comprising the Lower Silesian Coal Basin;
- the foredeep basin, comprising the Upper Silesian Basin;
- the epiplatform basin, which includes the Lublin Coal Basin.

The coal-bearing formation represents marine-paralic, paralic and continental sediments formed within the time span or Upper Viseau to Upper Westfalian.

Figure 4.2 Poland's Geological Structural Divisions



The most important of all three basins is the Upper Silesian Basin because of its size, coal production and coalbed methane potential. The location of Poland's Upper Silesian Basin is shown in **Figure 4.2**. The Upper Silesian Basin is situated in southern Poland and extends into the northernmost region of Moravia in the Czech Republic. The majority (two-thirds) of the basin area, defined by the extent of the Carboniferous coal-bearing formations, is situated within Poland.

The Lower Silesian Basin is located on the southwest side of Poland, approximately 160 km northwest of the Upper Silesian Basin. The Lublin Basin is 350 km north east of the Upper Silesian Basin. The basins extend into other countries, Upper and Lower Silesian - Czech Republic, and the Lublin Basin appears in the Ukraine.

The Upper Silesian Coal Basin was formed over the northern corner of the Upper Silesian massif, as a foredeep of the Moravo-Silesian Fold zone that occupies the western flank. The northeastern basin boundary is formed by the Cracow Fold Belt, which is superimposed on the dextral basement wrench-fault system separating two major crustal blocks. The crystalline basement of the Upper Silesia massif that constitutes a Precambrian crustal block forms the southeastern boundary. Due to its specific geotechnical setting, some features of the basin and its adjacent area are in contrast to those of other Variscan foredeep, such as the subtriangular shape, the considerable thickness of coal-bearing formations in comparison with their lateral extent and the sedimentary gaps in the formation sequence. The complex tectonic zonality of the basin is another contrasting feature.

The geological column of the Upper Silesian massif is comprised of rocks ranging in age from Precambrian to Quaternary. In general, the sequence may be divided into three parts, taking into account the occurrence of the coal-bearing measures:

- the basement of the basin;
- the productive coal-bearing part; and
- the overburden.

The Upper Silesian Basin basement consists of Precambrian, Cambrian, Devonian and Carboniferous rocks. The lowermost, Precambrian, part of the basement is composed of crystalline rocks—predominately paragneiss of different types, migmatic granite and olivine gabbro. The overlying Cambrian Formation rests discordantly on metamorphosed complex. It is a transgressive sequence of clastic rocks (ranging in thickness from 0 to 1,100 meters) and was deposited in a deep marine environment. The Devonian section of the basement that overlies the older basement complex is comprised of a basal clastic unit, which is succeeded by a sequence of dolomites (uniformly 250 to 290 meters thick) and it grades upward into organic and detrital limestone sequence. Maximum thickness of Devonian carbonate approaches some 1,200 meters. The Carboniferous section of the basement consists of the lower carbonates and clastic sequence (up to 285 meters thick), followed by clastics of marine origin. Thicknesses of 200 to 1,500 meters have been found.

The Carboniferous coal-bearing formations of the basin are considered as molasse sediments of the Variscan orogenic system. The 8,500-meter thick sequence of coal measures could be divided into a lower part, which are entirely silicoclastic marine coal-bearing strata. The upper part, separated at the base by a sedimentary gap, represents the continental deposition, which originated in a fluvial environment. The lower sequence and its coal potential vary within the basin due to its thickness and facies changes. Approximately 260 coalbeds are known, 114 ranging in economic thickness from 0.4 to 3.5 meters. This lower sequence is succeeded by the Upper Sandstone series, which is characterized by a predominance of coarse-grained sediments deposited in a fluvial and limnic environment. Total thickness approaches some 1,100 meters and pinches out in the eastern part of the basin. This is the major economic unit in the basin. Its total coal content ranges from 6 to 9% of the sequence. Some 61 coal seams are known, out of which 23 are of economic importance. The range in thickness is from less than 1 meter to about 24 meters. The average coal seam thickness is from 4 to 8 meters. This Sandstone series grades upward conformably into a mudstone series. The series is typified by cyclically alternating coal, claystone mudstone and sandstone. The thickness of the unit ranges from 100 meters in the eastern part, to some 2,000 meters in the central part of the basin. About 70 coal seams attain economic thickness which averages 0.9 to 1.3 meters thick. The uppermost part of the Carboniferous sequence is formed by a Cracow sandstone series. The thickness of the preserved part of the sequence ranges up to 1,640 meters. This series contains 38 coal seams of which 20 are of economic thickness. Some are 7 meters thick.

The coal-bearing Carboniferous formation of the basin is covered by Permian, Triassic, Jurassic, Tertiary and Quaternary deposits.

4.3 Coal Deposits and CBM Resources

Coal Deposits

The total number of coal seams recorded in sequences of all stratigraphic units is as much as 520. The beds range up to 24 meters in thickness. The total coal resources of the basin (as of 1987) amount to 103.7 billion tons. The estimates were done from a mining point of view, present mining techniques, depth limit (1,500 meters), and economic constraints. However, the coal seams of economic thickness occur down to the depth of 4,500 meters.

Complex coalification processes largely control the rank of Upper Silesian coal. Particular rank zones are not bound to specific deposits or stratigraphic zones. They are irregular discordantly intersecting the structure of carboniferous strata. There is a full set of coal rank and quality ranging from the sub-bituminous through high to low volatile bituminous to the high rank of anthracite. The vitrinite reflectance (Vro) ranges from 0.5 to 2.0%. As to the coal quality, the average ash content is in the order of 13% and the sulphur is relatively low in some 1.1%. The petrographical composition of mined coal is typically high in vitrinite; the exinite is subordinate. Most important for the coking properties is the content of inertinite, which ranges up to 65%.

CBM Resources

Despite decades of collecting data on methane occurrences in coal seams of the Upper Silesian Basin, the nature of the geological control over the distribution of gas in the basin still remains poorly understood.

The distribution of coalbed methane is primarily depth-related. The second factor controlling methane resources is the impermeable, argillaceous overburden of the Carboniferous strata, leading to secondary gas accumulation. The depth of the gassy coal top surface is variable through the basin area, ranging from 250 to 1,160 meters.

The commonly accepted control of methane content in coal seams by coal rank and depth of occurrence is considerably disturbed by other geological factors in the Upper Silesian Coal Basin. In the northern and central part of the basin, coalbed methane is present in small quantities or does not occur at all. In the southern portion of the basin, the methane content is fairly high in some areas. To some extent, the thickness and type of overburden and tectonic features control the content. The complex erosion history of the basin seems to play a decisive role in the formation of very deep zones of degassed Carboniferous strata.

The methane content of the Carboniferous coal seams in the Upper Silesian Basin varies over a very broad range up to 22 cc/g on a dried ash free basis (daf), the average methane content increasing with increasing depth. The gas content is low up to a depth of 600 meters; but the average gas content increases considerably within the depth range of 600 to 1,000 meters. Worthy of note is the very broad range of methane content in seams ranging from 0 up to 13 to 18 cc/g (daf), with some deep seams up to 1,800 meters totally devoid of methane.

The Polish Geological Institute estimates in-situ coalbed methane resources of the virgin exploration fields of the Upper Silesian Basin at 200 Gm^3. Some additional 150 Gm^3 of methane may be expected within the area of active coal mining.

4.4 Basin Assessment

Active coalbed methane drainage (mine degassifaction) is held continuously in seventeen mines of the Upper Silesian Basin and in the Rybnik Coal Region. Methane recovered by this method is a by-product of the mining and these areas would not be acceptable for CO_2-enhanced recovery operations.

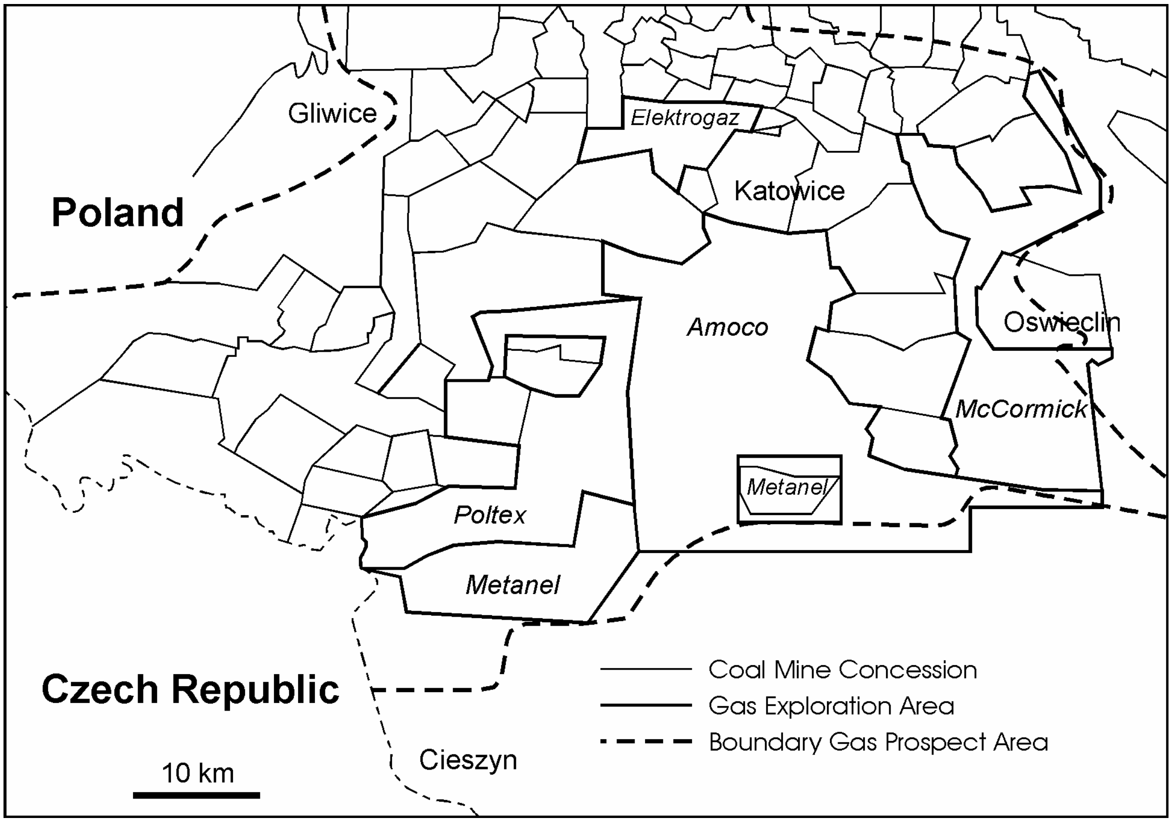
The first licensing round for coalbed methane exploration started in 1992 in three basins. Most activity was in the Upper Silesian Basin, while in the other two basins, Lower Silesian and Lublin Coal Basin, activity was limited.

4.4.1 *Upper Silesian Basin*

Five companies applied for these concessions and by the end of 1996, the companies owned their concessions within the Upper Silesian Basin only (**Figure 4.3**). In addition, two concessions in the Walbrzych area were granted. Most results from this activity have not been released into the public domain, but comparing public results from local mining activities in the regions can be helpful. The five companies were as follows:

a)	Amoco Poland Ltd.	120,000 acres	(488 km^2)
b)	McCormick	60,000 acres	(244 km^2)
c)	Metanel	6,670 acres	(27 km^2)
d)	PolTex Methane	NA	
e)	Elekrogaz	NA	

Figure 4.3 Original CBM Concessions Granted in 1992 Licensing Round



Amoco Concession Area

This was the largest individual concession awarded. It included virgin coal and four exploration concessions. In 1993, Amoco Poland Ltd. committed to drill 15 wells over the next 3 years and spend $10.0 million. Their activity was in the south-central part of the basin. To date, they have drilled 6 test wells and 8 coreholes. Some of the coreholes were drilled to depths of about 4,600 – 5,600 feet (1,400 to 1,700 meters). Results are as follows:

Number of coal seams	over 20
Thickness	up to 9 m (30 feet)
Gas Content	averaging 9.3 m^3/t (300 scf/ton) (as received)
Permeability	averaging 7.0 md (production test)
Ash Content	20%

Actual production rates have not been released to the public, but these results have been taken from conversations from ex Amoco personnel. The Amoco's CBM wells were dispersed. That was done on purpose to obtain data distribution on reservoir parameters in order to select the best site for the pilot project.

Amoco has finished its activity in Poland.

McCormick Concession Area

In 1993, McCormick Energy signed a contract to drill 9 wells on its 2 licensed blocks. Active mining is currently taking place on 3 sides of these blocks with 2 mining companies, Nadwislanska Spolka Weglowa SA and Katowice Coal Holding Company.

McCormick entered into an agreement to recover gas via gob wells and premining surface wells from Poland's second gassiest mine, Brzeszcze longwell mine #52. This mine is located in the southwest area of the licence area and produces sub-bituminous to high volatile B bituminous coal.

Results in 1994 indicated that a total of 4.41 Bcf (125 Mm^3) of gas was collected, with 1.56 Bcf of the gas collected coming from 3 in-mine boreholes. All produced gas was used for the mine's heating plant and by a local chemical plant.

Desorbed gas contents from whole core were as high as 480 scf/ton (15 m^3/t) (as received) in the area.

Similar results also occurred with the Jastrzabska Spolka Weglowa SA agreement over its Krupinski mine #58. A feasibility study was then completed to carry on or expand the operations, but McCormick had suspended its activities.

Metanel Area

Metanel's two licences, Silesia mines property #53 and in the Miedzyrzecze area north of mine #23 are located in the south central part of the basin. Results indicate that 1.45 Bcf of gas was recovered in Brzeszcze 's mine # 52. The recovered gas was again used in the mine's heating plant and by a local oil refinery at Czechowice-Dziedzice.

Of the total gas drained, 71% came from gob areas, and 22% came from the working faces. Seven percent was lost to the atmosphere due to poor operations. Gas content measurements, again from whole core, were as high as 340 scf/ton (10.6 m^3/t) (as received).

Metanel is continuing by adding a concession in the southwestern corner of the basin, the Drogomysl-Zebrzydowice exploration area.

PolTex Concession Area

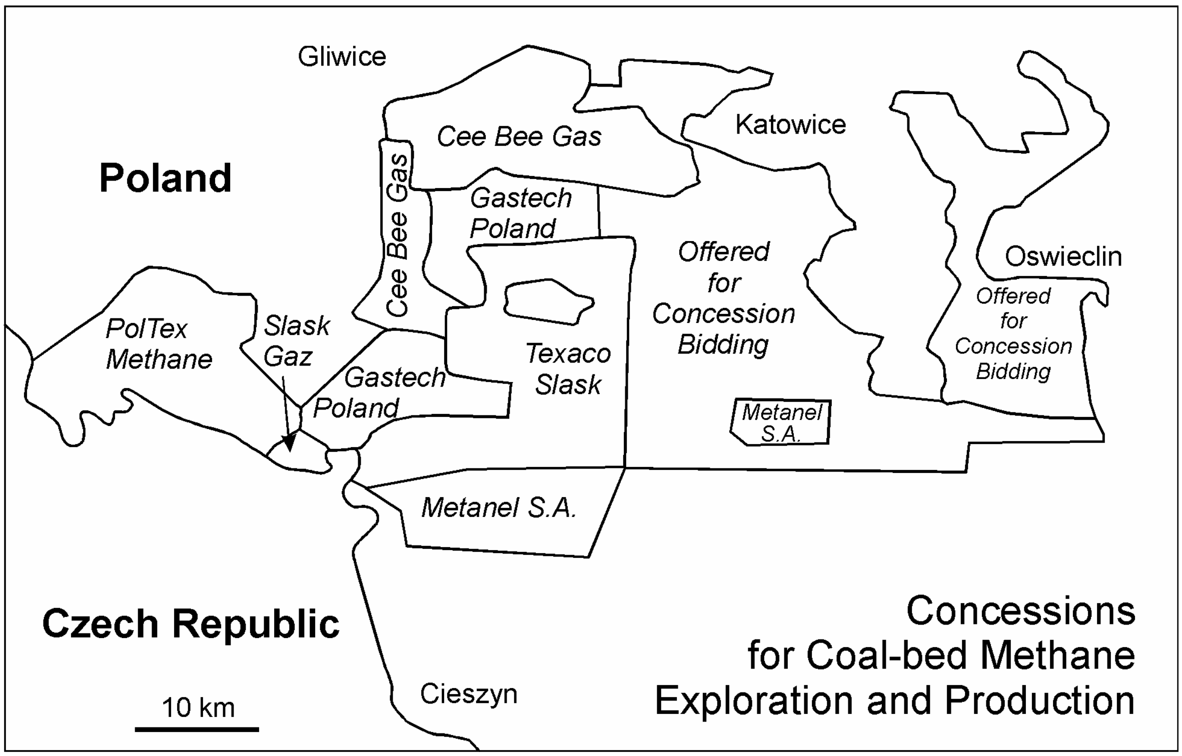
PolTex Methane is a Polish – Mackenzie joint venture. This license follows Amoco's property on the west, and has five exploration concessions attached. It also surrounds the Krupinski mine (#58), and part of the Pniowek mine (#63). The Pniowek mine recovered 4.46 Bcf (126 Mm^3) of methane, with 1.53 Bcf (43 Mm^3) coming from boreholes. The gas was used in the mine's heating plant and or sold to GOZO Zabrze, a gas utility company.

Gas contents from whole core have been measured up to 480 scf/ton (15 m^3/t) (as received), with average of 300 scf/ton (9.3 m^3/t). Other CBM laboratory analysis has been completed, but this information is not available.

PolTex drilled seven wells to maximum depths of 6,000 feet (1,820 m). Four were hydraulically fractured in the deepest coal seam encountered by a sand water frac. Results from two production tests indicated that economic gas was present.

There is currently a second wave of activity that is trying to understand the results of the previous work completed. Cee Bee Resources, Eurogas and Texaco are currently evaluating CBM prospects. There was no information on Texaco's 5-well production pilot drilled and tested during 1997-98. In fall of 1997 the concession of Amoco Poland expired and the released area will be offered for bidding. (**Figure 4.4**)

Figure 4.4 Current Status of CBM Concessions (April, 1998)



Eurogas has taken over the PolTex project and has brought in Texaco and currently is investigating the possibility of a North American power company supplying a 50 Megawatt (MW) power plant. Texaco will conduct a drilling and evaluation project and gain the right to develop the concessions in exchange for 20% of net profit interest.

4.4.2 Lower Silesian Basin

Vikelt Concession Area

Vikelt Ltd. was the lone bidder for a license in the Lower Silesian basin. In a one-test program, results from two thin coal seams were uneconomic. A total depth of 5,200 feet (1580 m) was drilled and both thin coal seams were stimulated with a sand water fracture. The operations were suspended.

CO_2 Sources

The Upper Silesian Region is the most industrialized and urbanized part of the country. It is situated in Katowice voivodship (county) and covers 2.1% of Poland. Eighty-seven percent of the population of 4 million inhabitants lives in towns.

Some 20% of the national industrial production come from the Katowice area, namely 98% of coal, 53% of steel, etc. There are more than 4,000 industrial plants. The total emission of gases is over 1.3 million tons per year, with CO_2 and SO_2 accounting for 73%. The area has developed a dense gas pipeline system, including high pressure gas transmission system, low pressure local distribution lines, core-oven gas lines and coalbed gas obtained from coal mine drainage.

4.5 Conclusion

The Upper Silesian basin is the basin of choice, as there is little activities in the other two basins. The former Amoco Concession area, south of the town of Tychy is selected as the potential site for the CO_2-ECBM pilot. This concession lease has expired and is available for bidding. Its proximity to industrial CO_2 sources and access to gas transmission pipelines makes it a viable site. It has a reasonable gas content. Typical reservoir parameters that can be expected from this area are shown in the following Table.

Table 4.1: Typical Reservoirs Parameters for the former Amoco Concession Area

Individual Seam Thickness	1 – 24 m
Cumulative Seam Thickness	52
Completable Thickness/Depth	<11 / 1,150 m
Permeability	Estimated 1 – 5 md
Coal Rank	Medium volatile bituminous,
Ash Content	Average 11%
Moisture Content	~3%
Gas Content	Average 8 m^3/t, up to 22
Gas Saturation	Undersaturated
Cleating	Good
Mineralization	None apparent

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CHAPTER 5
COUNTRY ASSESSMENT - INDIA

5.1 India Gas Market

India is the world's seventh largest energy consumer and consumed 12.5 quadrillion BTU (quads) of energy in 1998 (3.3% of the world total).

Coal is the dominant commercial fuel in India and supplies approximately 60% of the country's total primary energy requirements. Power generation accounts for about 70% of India's coal consumption, followed by heavy industry. The industrial users include iron and steel mills, foundries, fertilizer producers, paper manufacturers, and brick kilns. Coal consumption is projected to increase to 465 million short tons in 2010, up from 370 million short tons in 1998. A significant driver in the incremental coal demand is electric power generation. India is the third largest coal producer in the world (after the China and the United States), so most of the country's coal demand is satisfied by domestic production.

Oil and natural gas currently account for 30% and 8% of India's primary energy consumption respectively. While the utilization of natural gas in India began in the early 1960s, the volume of gas utilized increased significantly only in the early 1980s after gas became available from the Bombay High field in India's western offshore. Over the decade of the 1980s, gas consumption increased by 20% annually. It reached 0.6 Tcf (17 Bm^3) per year in 1995 and is expected to increase to 1.2 Tcf (34 bm^3) in 2000 and 1.9 Tcf (54 Bm^3) in 2005. Increased use of natural gas in power generation will account for most of the increase, as the Indian government is encouraging the construction of gas-fired electric power plants in coastal areas where they can be supplied with liquefied natural gas (LNG) by sea.

The recoverable reserves of natural gas in India are estimated at about 23 Tcf. About 70% of the country's gas reserves are found in the Bombay High basin and the state of Gujarat. Current projects include enhancing gas production at the Tapti fields and recovering previously flared gas at the Bombay High oilfield. Given that India's gas production is not likely to keep pace with domestic gas demand, India will have to import most of its gas requirements, either via pipeline or LNG tanker, making it one of the world's largest gas importers.

India is investing heavily in the infrastructure required to support increased use of natural gas, building LNG terminals and pipelines. Four large foreign financed projects are currently underway to facilitate imports of LNG. A consortium headed by British Gas is planning an import terminal at Pipavav, which will initially handle LNG imports from Yemen and will supply Gujarat. Enron is building an import terminal to supply its electric power generation plant at Dabhol with LNG to be supplied by Oman and Abu Dhabi. A consortium headed by Siemens is planning to build an import terminal at Ennore to supply an electric power plant. The Ennore project has been delayed by the lack of a power purchase agreement and financial guarantees. TotalFina of France is planning a facility at Tromaby, which will supply gas to a power plant and other users in Maharashstra.

One problem with the current investment climate in Indian imports is the lack of a coherent regulatory structure. The Indian Parliament is expected to put through a bill in year 2000 to set up a national regulatory body for natural gas and to allow for exclusive rights to be awarded in some areas to guarantee a market for new gas projects. Gas prices will not be fixed by the new scheme but a price ceiling may be imposed. All these will help the continuing development of gas markets in India.

Aside from LNG imports, land-based pipeline projects are also contemplated. One possibility is to supply India with gas from Iran's huge South Pars field via a subsea pipeline. Another possible route would link gas reserves of Bangladesh into the Indian gas grid. This kind of project takes a long time to negotiate and develop and most likely would not have much impact in the short term. Hence, current gas market development in India is in LNG and focussed around the coastal area to supply LNG to fuel electric power plants. In the interior areas, there is not much development. The Indian Government through the Directorate General of Hydrocarbons is encouraging coalbed methane exploration. Coalbed methane might be able to find a niche in India's energy supply mix.

5.2 India Coal and Coalbed Methane Resources

Coal Resources

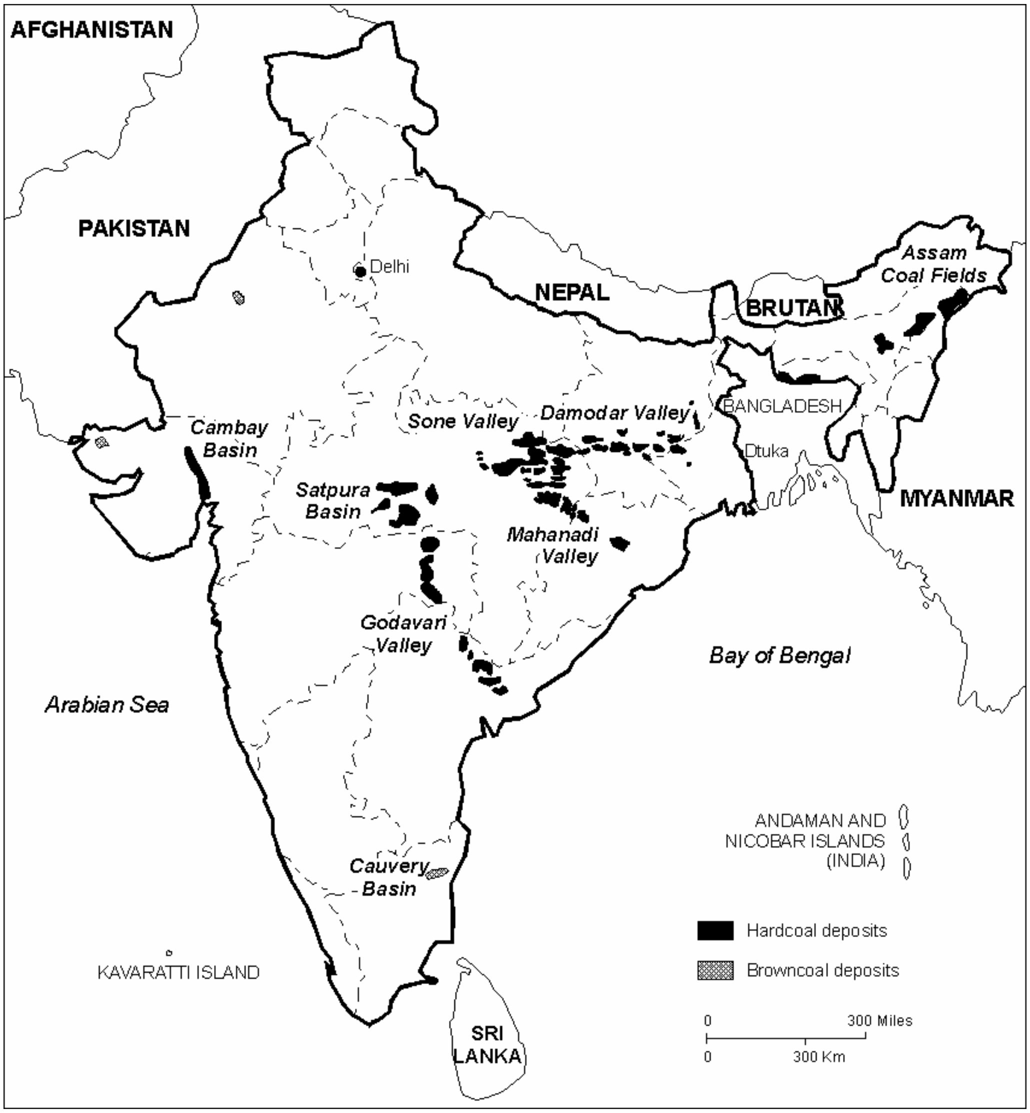
India has 7% of the world's proven coal reserves (US Energy Information Administration, 2000). By current estimates the reserves are enough to meet India's needs for at least another 100 years. The coal reserves are listed at 204 billion tons (and an additional 68 billion tons indicated). Coal deposits in India occur mostly in thick seams and generally at shallow depths. Non-coking coal reserves aggregate 172 billion tons (85%), while coking coal reserves are 30 billion tons (the remaining 15%). Ash content ranges between 15 and 45%. Currently, opencast mining is the predominant method used to exploit the 64 billion tons of proven reserves situated within a depth of 300 meters.

Most of India's coal demand is met from domestically mined reserves. However, as Indian coal has a high ash content and low calorific value, most coking coals must be imported. Major Indian coalfields are found in Bihar, West Bengal, and Madhya Pradesh. Nearly all of India's 390 mines are under Coal India Ltd. (CIL), which accounts for about 90% of the country's coal production.

Coalbed Methane Resources

There are numerous estimates of the coalbed methane (CBM) potential in India. However, although there is ample coal thickness and distribution data there is very little data concerning gas saturation and storage capacity. Estimates of the CBM resources (typically gas in place) are generally made by applying an estimate of an assumed gas content to estimated coal thickness and area. These estimates are at best a first approximation. Large potential CBM resources have been identified in the Damodar Valley area of Bihar and West Bengal in Eastern India and in the Cambay Basin in Gujarat, Western India (**Figure 5.1**).

Figure 5.1 The Coalfields of India.
(Modified From the International Coal Seam Gas Report, 1997).



Current estimates by the Directorate General of Hydrocarbons of CBM resources in India are of the order of 1,000 billion m^3 (Gm^3), assuming gas content of 5 m^3 per ton (Directorate General of Hydrocarbons, 1999). Boyer in his international assessment of CBM potential placed an estimate of approximately 850 Gm^3 for India (Boyer, 1994), although he noted that specific data to establish this estimate was lacking. The Oil and Gas Journal article on Indian CBM potential (Kelafant and Stern, 1998) estimated a range of 850 to 4,000 Gm^3 (30 to144 Tcf). Sawhney (1996) calculated potential coal seam gas resources to be 700 Gm^3 (25 Tcf) in India's five most prospective areas. One-half of the gas-in-place, or 350 Gm^3 (12.5 Tcf) was considered as recoverable. Engineers working in the Damodar Valley coalfields estimated 400 to 700 Gm^3 as a rough gas in place for the undeveloped areas in four Damodar Valley coalfields (Cooper, 1995). The Coal Mine Planning and Design Institute (CMPDI, 1999) has placed an estimate of at least 400 Gm^3 for the same area.

CBM test wells have been drilled in the Damodar Valley coalfields and in the Cambay Basin. The Oil and Natural Gas Corporation (ONGC) drilled at least four exploration wells and three more are planned in the Damodar Valley. Essar Ltd. drilled 3 CBM wells in the Cambay Basin. No sustained CBM production has been established in either basin. In these two cases, the operators have not released many specific details of the drilling results or testing programs covering permeability, volumes of gas and water produced. However, information on gas content, coal thickness and coal distribution/quality and some information on permeability levels have been noted.

5.3 India Coal Basins

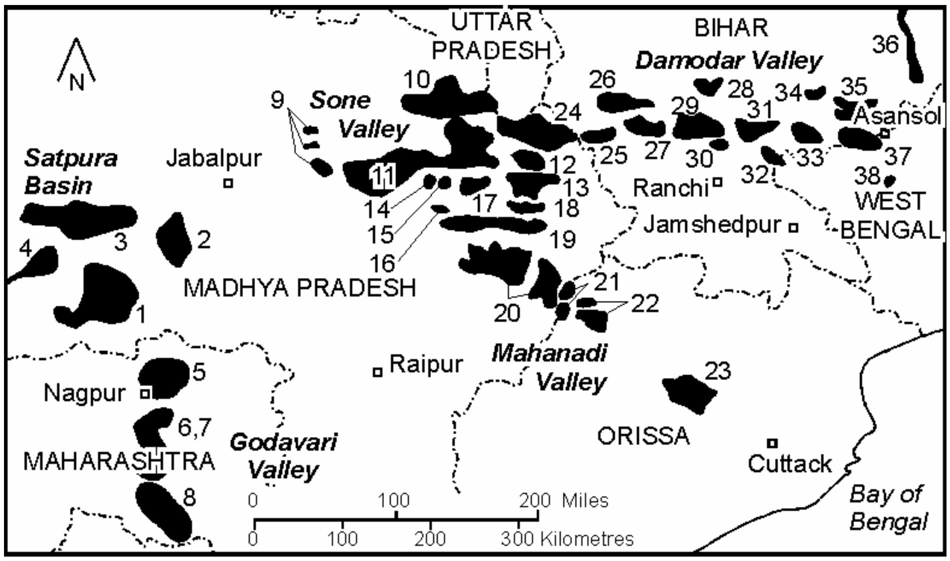
The coal bearing formations of India occur in two distinct geologic horizons: the Lower Gondwana (Permian) belts of Peninsular India and the Tertiary sediments (Eocene – Oligocene) of northwestern India in Gujarat and Jammu-Kashmir (Singh, 1987). The coals are located over a wide range of subsurface depths and exhibit different coal characteristics. India has numerous coalfields with potential for coalbed methane (CBM) development, which can be divided into five major geographic areas:

- Damodar – Koel Valleys
- Sone – Mahanadi Valleys
- Godavari Valley
- Assam Coalfields
- Cambay Basin (low rank Eocene deposits**)**

Only two of these areas (Damodar and Cambay) are actively being explored for CBM potential at the present time.

The bituminous coal fields of India consist of numerous isolated basins extending from the central states of Andhra Pradesh, Maharashtra and Madhya Pradesh northeastward through Orissa, Bihar and West Bengal, across Bangladesh, and into Assam (**Figure 5.1**). The majority of India's reserves are Permian Gondwana age coals, which are predominantly located in West Bengal, Bihar, Orissa and Madhya Pradesh (**Figure 5.2**). The three major coal field trends in these states are (1) the east – west trending Damodar – Koel Valley trend, (2) the northwest – southeast trending Sone – Mahanadi Valley trend and (3) the Godavari Valley. The thickest, most heavily mined and best-defined coals occur in the Damodar Valley. The other significant coal fields are Eocene coals in northeast India in and around Assam and also in Kashmir. There are also Jurassic, Cretaceous, Pliocene and Pleistocene minor lignite and sub-bituminous deposits.

Figure 5.2 Detail of Coalfields in East Central India.
(Modified From the International Coal Seam Gas Report, 1997).



Coal Fields

1 Pench-Kanhan	9 Sohagpur	17 Koreagarh	25 Hutar	33 Jharia
2 Mohpani	10 Singrauli	18 Lakhanpur	26 Daltonganj	34 Giridih
3 Tawa Valley	11 Sonhat	19 Hasdo-Arand	27 Auranga	35 Deogarh
4 Pathakhera	12 Jhilimili	20 Korba	28 Chope-Itkhori	36 Rajmahal
5 Kamptee	13 Bisrampu	21 Raigarh-Mand	29 North Karanpura	37 Raniganj
6 Umrer	14 Jhagrakhand	22 Ib River	30 South Karanpura	38 Barjora
7 Bandar	15 Chirimiri	23 Talchir	31 Bokaro	
8 Chanda Wardha	16 Sendergarh	24 Ramkola-Tatupani	32 Ramgarh	

Coal mining and resources are concentrated in the Damodar Valley, the Sone-Mahanadi Valley and the Godavari Valley regions of east and central India. Each of these elongated coal-bearing regions comprises a number of separate coal basins developed along a common structural trend. These regions share similar geological histories and employ the same stratigraphic nomenclature. Of the three regions, the Damodar Valley holds the greatest prospects for CO_2-ECBM recovery. It is the most studied and developed coal mining region in India; coal rank is substantially higher than that in the other regions.

The other coal-bearing region selected for analysis, the Cambay Basin in west India, offers opportunities for enhanced CBM production in a different geological and geographical environment. The Cambay Basin of Gujarat covers an area about 13,000 square miles (34,000 km^2) and has very thick low rank sub-bituminous Eocene coals. The Cambay Basin coals are not commercially mineable because of rank, quality and depth. ONGC initiated a pilot project for underground coal gasification but it was not commercially successful and the project was abandoned. This basin contains conventional natural gas deposits with developed gas-related infrastructure, and is located in the State of Gujarat, the principal industrial region of India.

In general, Indian coalmines are not considered very gassy because of the relatively shallow depth of mining. Locally high methane emission rates have been noted, particularly in mines that encounter faults or dikes especially in Jharia and East Bokaro coalfields. Banerjee (1987) classified 408 Indian coalmines (compiled by Ghose at Coal India in the 1980s) according to their degree of gasiness.

Gasiness	Methane Emission Rate	No. of Mines
Degree I	<1 m^3/Mg (<32 scf/ton)	263
Degree II	1-10 m^3/Mg (32-320 scf/ton)*	122
Degree III	>10 m^3/Mg (>320 scf/ton)	23

* Or if >0.1% flammable gas is detected in mine air.

Methane drainage has been attempted in several mines, but efforts through the 1980s generally were unsuccessful, uneconomic or not pursued. When gas volumes exceed the dilution capacity of the ventilation system, the methane is drained by in-mine pipeline and released into the main return air. Controlled bleeding routinely drains sealed areas, and there has been limited gob well usage. No surface drainage facilities or drained gas utilization has been implemented. In 1990, total mine methane emissions from drainage and ventilation systems amounted to 670 million m^3 (24 Bcf), with none utilized (Mase et al., 1995). The United Nations Development Program (UNDP), in an effort to minimize harmful greenhouse gas emissions in India, plans to use gob, in-mine drainage and other methods to recover and utilize coalbed methane gas produced during coal mining activities.

5.3.1 Damodar Valley

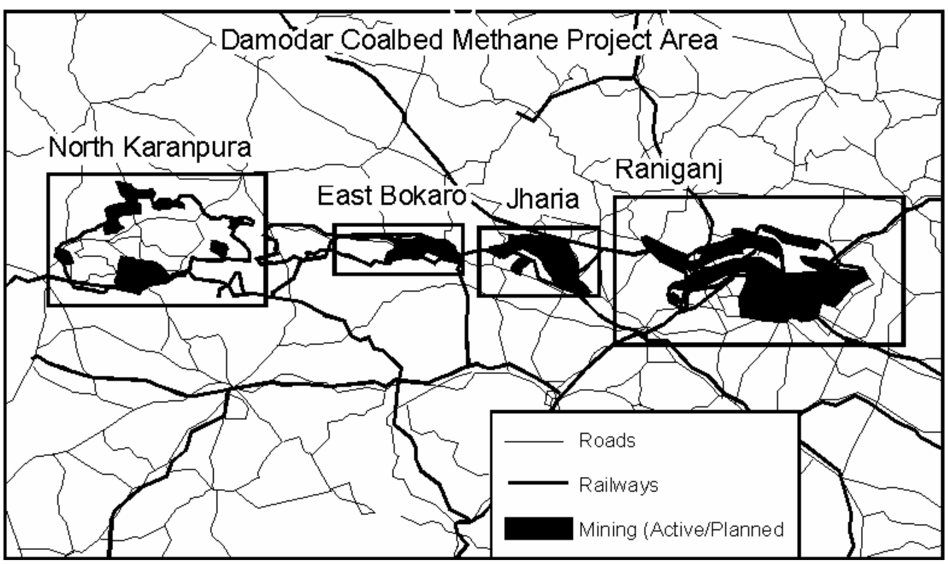
Damodar Valley coalfields are located in eastern India in the states of West Bengal and Bihar. The coalfields in eastern India were deposited during the Permian age Gondwana period. Coal was deposited on the supercontinent known as Gondwanaland, which included India, Africa, Madagascar, Australia, Antarctica, Arabia and South America. Gondwana coalfields have been developed in India, Australia, South Africa, Zimbabwe and Brazil. These coals generally share similar characteristics. The coals vary but tend to be ash rich (mineral matter), inertinite – rich, and vitrinite – poor.

The Damodar Valley coalfields are located in a rift structure in the eastern India shield province. There are igneous intrusions encountered in the central part of the Damodar Valley. The Damodar Valley coalfield stretches intermittently almost 500 kilometers (300 miles) in an east west direction but the individual fields are only 15 to 50 kilometers (9 to 31 miles) wide in a north - south direction. At the time of deposition the coal forming swamp probably continued in a continuous to a semi-continuous manner. Subsequent erosion has left the current isolated coalfields. The Damodar Valley coalfields are preserved as graben and half graben structures. The dominant fault in these fields is the south bounding fault. Within the Damodar Valley coalfields faulting and intrusive activity (mainly as dikes) have complicated the structure of the basin. The Coal Mine Planning and Design Institute notes that the faulting and igneous activity causes a complex structural character which has an effect on the resource potential and mineability of the seams. It will also have an effect on CBM development.

The Damodar Valley coalfields provide a favorable combination of coal thickness, rank and burial depth suitable for coalbed methane development. They have the thickest coals, and highest rank bituminous coals of any of the Indian coalfields. The two principal coal-bearing formations are the older Barakar and younger Raniganj. The Barakar formation is the main coal-bearing formation. This formation has coals from 0.5 meters (1.5 feet) to over 60 meters (200 feet) thick in most of the Damodar coal fields. The Raniganj is the thickest and most developed in the Raniganj coalfield in the eastern end of the trend. It has limited development in Jharia and is insignificant elsewhere. The Raniganj formation in Raniganj field has up to 12 seams, each of 1 to 11 meters (3 – 36 feet) in thickness. Maximum individual seam thickness in the Raniganj formation reaches 20 meters (66 feet).

Rank of these high-ash coals is highest (medium-volatile bituminous) in Jharia and Bokaro fields and decreases eastward and westward to high-volatile C bituminous on the eastern side of Raniganj and the western end of North Karanpura (**Figure 5.3**). Jharia, India's second largest coal field contains some of the country's few prime coking coals. The Geological Survey of India has identified the Jharia, Raniganj and Bokaro fields as good candidates for coal seam gas potential.

Figure 5.3 The Main Damodar Valley Coalfields.
(Modified from Cooper et al., 1995).



ONGC has drilled at least four CBM exploration wells in Jharia and Raniganj coalfields. Information has been released from the ONGC JHA-A well located in the Parbatar block in the southern part of Jharia coalfield. This well was production tested for two and a half months and averaged about 1,100 m^3 per day (40 Mcf/d) from the XIV coal seam. Two additional wells were drilled in the Parbatur block and one well was drilled in the Raniganj basin. No information was released on the additional wells in the Parbatur block and the Raniganj well was disappointing. Indian companies, Essar Oil and Reliance as well as the Gas Authority of India Limited (GAIL) have expressed an interest in developing CBM in the Damodar Valley.

Most of the gassiest mines are found in the Raniganj, Jharia, Bokaro, and Karanpura coal fields, Bihar and West Bengal (Banerjee, 1987). A survey of 14 mines in the early 1980s revealed maximum desorbable gas contents of in-mine borehole samples ranging from negligible to 5.5 m^3/Mg (176 scf/ton) (Banerjee et al., 1987). Higher gas contents and methane emission rates were being encountered as depths of mining increased. Two of the country's gassiest coal seams have been studied in detail. Their characteristics are summarized below. The wells ONGC drilled in the Parbatpur block of Jharia field, were just south of the Amlabad coal mine targeting the XIV and XV seams. These data were complied from Banerjee (1980), Ramaswamy and Rao (1991 b) and the International Coal Seam Gas Report (1997).

Seam XIV, Amlabad Mine, Jharia

Thickness	12 m (39 ft)
Depth	450 m (l,476 ft)
Gas emission rates	3- 12 m^3/min (153 -160 10^3 Mcf/d). Recorded from 1971-77.
In situ gas content (Seams XIII, XIV, XV) (Direct Method):	
Desorptable	6.3 m^3/Mg (202 scf/ton)
Total	7.8 m^3/Mg (250 scf/ton)
Gas composition	94.4% CH_4, 3.8% N_2, 1.74% CO_2, 0.06% O_2

Resources (Jharia field):

Coal (to 1,200 m)	19.4 billion Mg (21.4 billion short tons), proved and indicated
Gas in place	116.5 billion m^3 (4.1 Tcf)

Disergarth Seam, Chinakuri Mine, Raniganj Field

Thickness	3.3 m (11 ft)
Depth	650 m (2,133 ft)
Gas emission rate	average 7.6 m^3/Mg (244 scf/ton)
In situ gas content (total)	5.9 m^3/Mg (189 scf/ton)

Resources (Raniganj field):

Coal (to 1,200 m)	19.2 billion Mg (21.2 billion short tons) proved and indicated
Gas in place	96 billion m^3 (3.4Tcf)

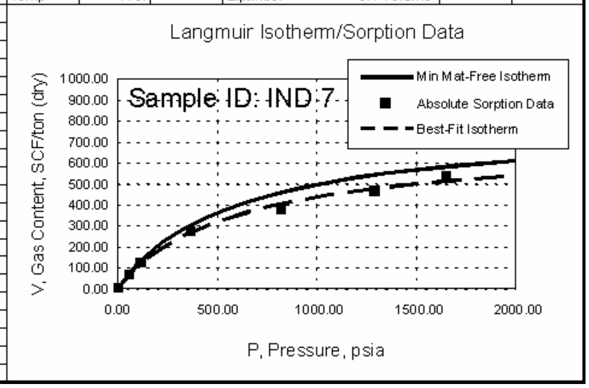
There is a wide variation of ash content and maceral distribution (vitrinite vs. inertinite) for the coals in the Damodar Valley. **Figure 5.4** is a plot of Langmuir isotherms from the Amlabad coal mine in the Jharia coalfield. The sample is from the Barakar XV seam and is typical of the coals in the Jharia coalfield. This is also one of the seams targeted by ONGC in their wells in the Parbatpur mining block to the south and is just above the XIV seam listed above. The coal has a mineral matter content of 14.8% which is slightly lower than average. The maceral content is a mix of 57% vitrinite and 42.6% inertinite. The sample has a vitrinite reflectance of 1.08% making it a medium volatile bituminous coal.

Figure 5.4 Langmuir Isotherm from the Amlabad Mine, Jharia. (Modified after Cooper et al., 1995).

Langmuir Isotherm - Jharia Coalfield

Langmuir Isotherm		*Amoco Production Research - Reservoir Technologies - Coalbed Methane*		
	Mineral Matter (dry)			
	14.82%			
b	**VM**	**VM**		
l/psi	SCF/ton	SCF/ton	**Experimental Data**	
0.001805	**638.48**	749.57	**Absolute Sorption**	
P	**V**	**V**	**P**	**VTRUE**
psia	SCF/ton	SCF/ton	psia	SCF/ton
0.00	0.00	0.00	**0.00**	**0.00**
100.00	97.63	114.61	**64.40**	**66.95**
200.00	159.36	198.82	**130.05**	**122.72**
300.00	224.29	263.31	**378.10**	**273.95**
400.00	267.71	314.28	**816.60**	**368.30**
500.00	302.88	355.58	**1293.35**	**417.17**
600.00	331.973	389.72	**1631.30**	**503.58**
700.00	358.41	418.42	**0.00**	**0.00**
800.00	377.24	442.87	**0.00**	**0.00**
900.00	395.21	463.97	**0.00**	**0.00**
1000.00	410.88	482.35		
1100.00	424.82	498.50		
1200.00	436.82	512.82		
1300.00	447.69	525.59		
1400.00	457.46	537.05		
1500.00	466.27	547.39		
1600.00	474.27	556.78		
1700.00	481.55	565.33		
1800.00	488.22	573.16		
1900.00	494.34	580.35		
2000.00	499.09	586.97		
Instructions				
Enter sample description information				
Enter additional measurement data				
Enter values for VM & b				
Enter value formineral matter (dry)				
Enter experimental sorption P & V(absolute)				

Sample Description			**Additional Measurement Data**	
Country	India		Moist: As Rec.	1.35% mass
Basin	Damodar		Eq Moist:	3.49% mass
State	Bihar		He Density:	1.5 g/cc
Well API#	97-357-99800-18		ASTM Rank:	MvBit
Formation	Barakar		Vol Mat:	26.49 dmmf
Seam	XV		Heat Value: 14868 BUT/bm mmmf	
Depth	Amiabad Mine		Min Mat:	14.82% dry mass
Sample ID	IND 7		Pure Coal:	85.18% dry mass
Notes			Vit Reflect:	1.08
			Vitrinite:	57 volume
Moist		mass	Inertinite:	42.6 volume
Temp	115F		Liptinite:	0.4 volume



The isotherm shows saturation potential of 9.4 to 15.6 m^3/Mg (300 – 500 scf/ton), at the range of reservoir depths and pressures. Other isotherms from these coals in the Damodar Valley show higher gas contents for higher vitrinite percentages with similar rank coals. The average gas content at Jharia coalfield is estimated to be around 12.5 m^3/Mg (400 scf/ton). The upper range of gas content can be up to 18.7 m^3/Mg (600 scf/ton). The Parbatpur block has the highest desorbed gas content in Indian coals measured by the Central Mining Research Institute at about 15 m^3/Mg (480 scf/ton)

Gas quality in the deeper seams is nearly pure methane with higher concentrations of carbon dioxide reported in shallow coal seams in Bokaro, Raniganj and Jharia mines (Banerjee, 1980). The gas quality for the Amlabad mine listed above was 95% methane. The CO_2 in the shallow seams is probably the result of igneous intrusions. CO_2 is also found in deeper seams adjacent to the igneous dikes.

Damodar Valley Coalfields Ranking

- **Jharia**
  - thick coal,
  - abundant coal deeper than 300 meters,
  - coal distribution well known,
  - very favorable coal rank,
  - existing three wells drilled for CBM,
  - moderate area, good rail and road access,
  - close proximity to CO_2 source, proximal to steel and other manufacturing areas.

- **East Bokaro (and West Bokaro)**
  - very thick coal,
  - abundant coal deeper than 300 meters,
  - coal distribution well known,
  - very favorable coal rank,
  - no wells drilled for CBM,
  - small to moderate area, good road access,
  - close proximity to CO_2 source, proximal to steel and other manufacturing areas.

- **Raniganj**
  - moderate to thick coal,
  - abundant coal deeper than 300 meters,
  - coal distribution well known,
  - favorable coal rank – less favorable in eastern part.
  - One existing well drilled for CBM (east of main field area),
  - large area, good rail and road access,
  - fair proximity to CO_2 source, proximal to steel and other manufacturing areas.

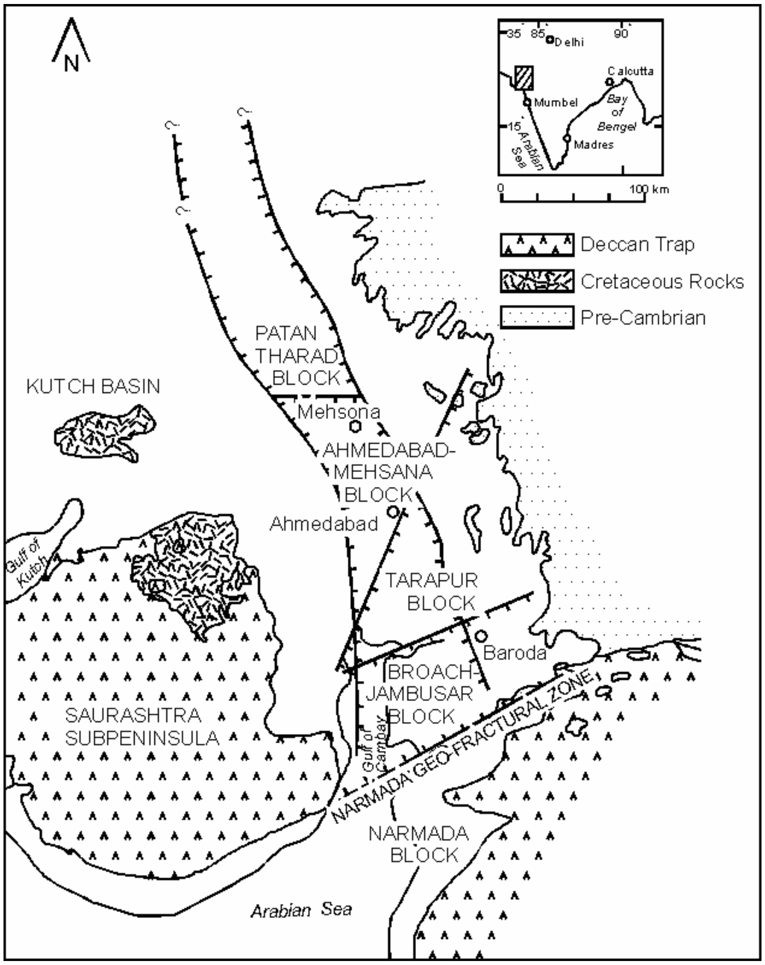
- **North Karanpura**
  - thick coal identified in the eastern part of the coalfield,
  - appears to have abundant coal deeper than 300 meters,
  - coal distribution defined in eastern part and less explored elsewhere,
  - favorable coal ranks in eastern portion and becomes questionable to the west,
  - no wells drilled for CBM,
  - large area, poor road access no rail access,
  - distant to CO_2 source, distant to steel and other manufacturing areas.

The Bokaro Steel Plant and the Chandrapura coal-fired power plant are directly adjacent to the Bokaro/Jharia area. The Santaldh coal fired power plant is south of Jharia. However, the Raniganj area is much farther away. All these plants could be considered as CO_2 sources.

5.3.2 Cambay Basin, Gujarat

The Cambay Basin is a large intracratonic rift basin, which extends in a north - south direction from the Gulf of Cambay to the northernmost part of Gujarat. It covers an area about 13,000 square miles including the Bay of Cambay. The basin margins are defined by discontinuous step faults, bounded to the west by the Saurashtra (or Kathiawar) uplift and to the east by the Aravalli ranges (Precambrian shield). ONGC has divided the basin into to four structural areas on identifiable basement fault trends: (1) Mehsana –Ahmedabad; (2) Cambay – Tharapur; (3) Jambusar - Broach; and (4) Narmada (**Figure 5.5**). The basin continues as a graben and merges into the Bombay Offshore basin.

**Figure 5.5 Cambay Basin Tectonic Map.
(Modified From Rao, 1997).**



The Cambay Basin originated in the late Mesozoic era as a failed rift, as tensional faults developed in the northwestern part of the Indian craton. Rifting was accompanied by Deccan volcanic activity, which covered large portions of the Indian subcontinent. The Tertiary sediments (including what would become the coal seams) were deposited on a Cretaceous volcanic basaltic basement. The basin is narrow and elongate with a broad north-south trend. The eastern and western boundaries of the basin are prominently marked by marginal faults, which are not sharp but extend over a zone, resulting in the formation of a narrow basin, reducing in its width towards the northwest. The most prominent structural feature of the basin is the Mehsana horst. It is 30 km long and 8 km wide at the top of the Paleocene. The eastern and southern flanks of the horst are well delineated. East and southeast of the horst and west of the eastern margin fault the Tertiary sedimentary section exceeds 5 - 6 km. On the eastern flank of the depositional basin the coalbeds cover a large area.

Paleogene coals in the Cambay Basin are known from oil exploration drilling (Ramaswamy and Rao, 1991). The Kalol coals, with 40 meters (130 ft) gross coal thickness, are sometimes oil and gas bearing. Pertinent data about the deeper, more extensive Sobhasan coals in a non-oil-bearing area were described from a coal gasification test well drilled by the

Oil and Natural Gas Commission near Mehsana. Thick Sobhasan coal seams have been identified at depths between 600 and 1,200 meters (1,970 and 3,940 ft) in a preliminary gas target area of about 500 km^2 (200 mi^2) around Mehsana (Ramaswamy and Rao, 1991).

Many companies are interested in CBM development in the Cambay Basin, including Essar, ONGC and Reliance. Gujarat is one of the most industrialized states in India and has a great need for natural gas. The wellhead price ranges from US$ 2.50 to 3.00 per thousand standard cubic feet and is expected to escalate. The supply of CO_2 should be readily available.

The Cambay Basin of Gujarat has very thick low rank sub-bituminous Eocene coals. These coals were first identified in well bores drilled for oil and gas. ONGC has identified over one hundred wells with these coals behind casing. This area has received significant attention because of production tests on several wells. These coals are similar to, but higher rank than, the Powder River Basin coals in Montana, USA and similar to, but lower in rank than the Wilcox coals in the Gulf Coast, USA. Although these coals are low rank (and lower gas saturation), they are very thick and extensive. Essar Oil Company drilled 3 CBM wells in the Cambay Basin using US Agency for International Development funding. The gas content for these coals was encouraging given the low rank of the coals. The Powder River Basin demonstrates that significant production can actually be produced from low rank coals. Sequestration capacity may be significant.

The coals in the Ahmedabad-Mehsana block are extensively developed within the early to middle Eocene oil bearing Kadi and Kalol formations. Middle Eocene coal seams are largely confined to the vicinity of Ahmedabad and Kalol. The early Eocene coals are best developed in the area around Mehsana, Sobhasan and north Kalol. Two persistent coal seams have been identified in the lower part of the middle Eocene Kalol formation. These two coal seams have been named the Kalol-IX (upper) and Kalol-X (lower). The strata overlying the Kalol-IX do not contain any significant coalbeds except in the immediate vicinity of Kalol.

The Kadi formation is subdivided into two members – the Mensana and the Mandhali. The Mensana member is characterized by several thick coal seams 20 – 50 meters thick, called the Sobhasan seams with a few thin seams interbedded with sands and shale. The thickness of the Mehsana member gradually thins to the east approaching the basin margin along with thinning of the coal seams. The Mandhali member also contains coal ranging from a few meters to up to 10 meters thick. These coals are not laterally persistent.

The Sobhasan I seam varies from 25 – 35 meters thick, the lower Sobhasan II seam averages around 20 meters, and the Sobhasan III seam is about 15 meters thick and combines with the II seam in areas to form a composite 35 meter thick. Gas contents have been stated to be in the range of 4 to 6 m^3 per ton (140 to 200 scf/ton), which appear to be high based on the low rank of these lignitic to sub-bituminous coals

Essar Pilot Wells

The United States Agency for International Development (USAID) supported the initial wells drilled by Essar. It was under the auspices of the Program for Acceleration of Commercial Energy Research (PACER). Under the program three wells were drilled and were to be followed by a pilot project. Two wells were drilled 8 kilometers apart. These wells, the LBM #1 and LBM #2, were drilled completed and stimulated. The third well, the

LBM #3 was drilled as an offset to the LBM #1 as part of an intended five spot pilot that has yet to be drilled. Based on data from these wells and numerous well logs from conventional oil and gas wells in the area it appeared that the three main coal interval were laterally persistent and relatively thick throughout the Essar project area in the Mehsana field. These wells were drilled and the coal seams were cored, but recovery and preservation were poor to fair. The seams were hydro-fractured, flow tested and the data were analyzed by reservoir models. Essar's exploration effort is so far the only CBM attempt in the Cambay Basin.

Essar first encountered the target coal seams at a depth of 1,340 meters. The coalbeds are in two distinct beds, separated by a two-meter shale bed. The shale thickens to the southeast and east as in an exploratory well about 8 km southeast of the first well and in a conventional exploratory well about 7 km east northeast of the well. The thickness of the shale bed remains nearly the same towards the west, the deeper part of the basin. The number of coalbeds also increases towards the deeper part of the basin as indicated by an exploratory well a few kilometers northwest of the pilot project well.

The main coal seam is divided into an upper and lower member which are separated by a two meter shale interbed. The Sobhasan II is the lower bed, which is 17 meters thick. The overlying Sobhasan I is 35 meters. A small hydrofrac with limited sand was used to stimulate both members. Injection fall-off test indicated a slight overpressuring of the coalbed reservoir. Limited permeability measurements to date are reported to be in the 0.5 - 3 md range (Kelafant and Stern, 1998). Below the targeted coal there are a few more coal beds each varying in thickness from 10 to 15 meters. They would have potential for coalbed methane, except these coals are limited in extent and are not homogenous in the pilot area.

The exploratory wells encountered a strong water flow and a large amount of produced coal fines. Essar attempted to dewater the coal seams in the exploratory wells with a progressive cavity pump and then by beam pump. The progressive cavity pump experienced >50% down time in the 8 months period but pumped out a substantial amount of water. A beam pump was then used for at least 2 years and brought the water level in the well below the depth of perforations. An undefined amount of gas was produced.

Cambay Basin coal seams are lignitic to sub-bituminous in rank, have high moisture contents and low to intermediate ash and sulfur Petrographic analysis determined that the maceral content of the coals is dominantly ~90% vitrinite with remaining amount split between liptinite and inertinite. Mineral matter is low ranging from 2 to 10%. Proximate analysis was done on three samples. A coal sample from the central part of the basin on an air-dried basis has 11% moisture, 51.9% volatile matter, 35.5% fixed carbon and 1.6% mineral matter. Another sample from an exploratory well in central part of the basin gives the following on an "as received" basis 17.2% moisture, 39.5% volatile matter (48.5% dry mineral matter free), 41.9% fixed carbon and 1.6% mineral matter. A third coal sample collected towards the margin of the basin had 10.1% moisture, 41.6% volatile matter (52.4% dry mineral matter free), 37.8% fixed carbon and 10.5% mineral matter (Rao, 1997). Vitrinite reflectance (Ro values) from more than 100 core samples from the pilot project wells varied from 0.30 to 0.46%, the mean was 0.36%. The basin margin well has Ro values ranging from 0.30 to 0.32% (Rao, 1997)

Three areas were analyzed in the Essar study (Rao, 1997), one on the eastern edge of the basin and the other two in the central part of the basin. The mid-basin well had gas content varying from 4 m^3/ton to 8.8 m^3/ton on an "as received" basis. The majority of the samples gave a value between 5-6 m^3/ton. The coals from eastern margin well had gas content which varied between 2 to 4 m^3/ton and only one sample with a value of 5.78 m^3/ton. These values are expected, due to the decrease in the coal rank towards the margin of the basin. Direct method desorption tests on core samples (depths unknown) collected by the Central Mining Research Institute, the research subsidiary of Coal India Ltd, indicated a maximum gas content of about 4.7 m^3/Mg (150 scf/ton) for Sobhasan coals at Mehsana (Sarkar et al., 1996). No data were available for Kalol coals, but they too were believed to contain gas. TerraTek Laboratories of Salt Lake City, Utah, USA ran isotherms on two samples from different wells. The coal has a gas content of 7.8 m^3/ton (250 scf/ton) at the formation pressure (Rao, 1997)

5.3.3 Other Coal Areas

Several companies have proposed coal seam gas exploration in Madhya Pradesh and Orissa. Areas include Sohagpur and Pench-Kanhan coalfields located in Madhya Pradesh, and in Talchir coalfield, located in Orissa (see **Figure 5.2**). The Pench-Kanhan Valley field lies on a monoclinal structure and includes two workable coal seams 2 to 7.5 meters (6.6 to 25 ft) and 1.2 to 2 m (4 to 6.6 ft) thick. Coking capacity of the high-volatile B to A bituminous coal increases from east to west. Sohagpur is among the principal coal fields of the Rewa basin in the Sone River Valley. The Lower Barakar Formation coal measures include four seams 1.5 to 2.4 meters (5 to 8 ft) thick and one extensively worked seam as thick as 11 meters (36 ft). Coal rank is high-volatile B bituminous. Barakar coal measures at Talchir, the country's seventh largest coal field, occupy a graben structure and include four seams aggregating from 17 to 54 m (56 to 177 ft) in net thickness. Coal rank is high-volatile C bituminous (International Coal Seam Gas Review, 1997).

UNDP Project

The United Nations Development Program (UNDP) will provide US \$10.3 million to support India's efforts to minimize harmful greenhouse gas emissions, by helping to recover and utilize coalbed methane gas produced during coal mining activities in the country. India's Department of Economic Affairs and the Coal Ministry and UNDP signed this agreement in New Delhi on 11 June 1998. The Global Environmental Facility (GEF), a partnership among the UNDP, UN Environmental Program (UNEP) and the World Bank will fund US \$9.19 million. The remainder will come from the UNDP/Government of India Country Cooperation Framework funds.

The main objective of this project is to demonstrate the commercial feasibility of recovering and utilizing CBM before, during and after coal extraction in the country. Harnessing CBM assumes special significance in India since coal remains the country's predominant source of energy. Coal accounted for 60 to 65% of India's primary energy needs over the past decade. According to estimates from the Central Mine Planning & Design Institute and Coal India Limited, both of which will be associated with the implementation of the Project, CBM could add 400 billion m^3 to the country's gas resources (this estimate is a conservative estimate for the Damodar Valley coal fields assuming full saturation).

There is a possibility that the UNDP project could be done in association with a CBM enhancement - CO_2 sequestration program.

5.4 Cambay Basin versus Damodar Valley

Gas markets

Cambay: Gas development in Gujarat would find ready market for power generation and industrial use. Currently, coal for power generation is brought in from the eastern coalfields. There is an established local natural gas market that is currently under-supplied. The Mehsana block has good access to a pipeline. It is 50 km from an established gas field near Nardipur.

Damodar: There is little infrastructure for natural gas pipeline transportation and usage. There is a small pipeline used for "coking gas". The Bokaro steel plant is located adjacent to these coalfields and the major industrial city of Jamshedpur is south of the fields. Calcutta is also a potential market if enough proven reserves can be established to justify a longer pipeline. The Hazira-Bijaipur-Jagdishpur (BHJ) National Pipeline is 550 km to the northwest.

Infrastructure

Cambay: The Cambay Basin in the western state of Gujarat is a mature oil and gas province. The drilling, completion and stimulation services and field supplies necessary for CBM development, are for the most part readily available.

Damodar: Damodar Valley is mainly a coal mining area, so accessing CBM services may be difficult and expensive.

Regulatory

Cambay: The Essar prospect area in Mehsana is estimated to be 4,000 km^2, all of which is likely to remain non-mineable due to the depth and low rank of the coal. The Gujarat/Cambay CBM play has attracted interest from local companies such as Essar and Reliance and foreign companies. The play has been delayed on ownership issues concerning the state of Gujarat, ONGC (with conventional oil and gas operations) and the Director General of Hydrocarbons. There are some discussions between state of Gujarat and the Director General of Hydrocarbons on the regulation of the CBM development of the Gujarat coals.

Damodar: The Parbatpur block is close to an existing coal mining area. Coal India has expressed concerns about CBM development and future mineability of the coal seams, even though the seams targeted would be deeper than current mining.

CO_2 Sources

Cambay: The Parbatpur block in the Jharia coalfield is 25 km from the Santaldh and Chandapura coal fired power generation plants. These plants would be able to provide large amounts of flue gas for the injection but would require the appropriate treatment.

Damodar: The Damodar Valley area has several electric power plants. The Mehsana block is 60 km from the Gandhinagar coal fired power plant. These power plants could be consumers of produced CBM and a source of CO_2.

5.5 India CBM Concession Areas

The Directorate General of Hydrocarbons (DGH) of India is the regulatory body for preparing terms and conditions for CBM exploration and development. However the Ministry of Coal and Coal India would still be involved in the areas where coal mining may be impacted.

The DGH has formulated a package of regulations for Coalbed Methane Exploitation. In July 1997, the Government of India approved a policy for exploration and exploitation of CBM gas. This Ministry has taken steps to implement the policy on CBM blocks being identified for exploration and exploitation. The Project involves 4 phases:

Phase 1: Exploration
Phase 2: Pilot Assessment and Market Confirmation
Phase 3: Development
Phase 4: Production

India is trying to commence Phase 1 and is starting by offering the relatively shallow depth coalbeds of the Lower Gondwana of the eastern and central parts of Peninsular India. The areal extent of these coalbeds is in the order of 11,000 square kilometers and includes the following:

- 2,800 km^2 in the Raniganj, Jharia, East Bokaro, and West Bokaro coalfields in the Damodar Valley belt **(Figure 5.3)**; and
- 8,200 km^2 in the Sohagpur and Satputra coalfields of Central India **(Figure 5.2)**.

Within these areas, DGH, in consultation with the Ministry of Coal, proposed an outline of a total of 10 blocks, varying in size from 200 to 500 km^2. The DHG has assembled a model CBM contract that is very similar to the previous oil and gas bid rounds. It is unclear what is the current status of blocks being awarded for coalbed methane exploration by the Indian Foreign Investment Board and the Coal Ministry. We are aware that blocks had been awarded to Modi- McKenzie consortium and later to Reliance – Enron. At best, additional CBM exploration would not begin until mid 2000.

Political Considerations

Recent developments in India have been dominated by the decision in May 1998 to carry out a series of nuclear weapons tests. As required by the Glenn Amendment, the United States imposed sanctions against India. By far the most significant sanctions were the suspension of U.S. government credits and guarantees, such as Eximbank financing and US Overseas Private Investment Corporation (OPIC) risk insurance, and U.S. opposition to further loans from International Financial Institutions (IFI's) such as the World Bank and the International Monetary Fund (IMF).

In October 1998, after India and Pakistan had declared moratoriums on nuclear testing, and had made commitments to eventually adhere to the Comprehensive Test Ban

Treaty (CTBT), the U.S. Congress passed a bill providing the President the authority to waive some of the sanctions measures for a period of one year. In November 1998, the most significant sanctions dealing with OPIC and Eximbank activities, as well as mandatory U.S. opposition to further IFI loans to India, were suspended. Nevertheless, this political factor may have impact on the financeability of CBM projects in India.

5.6 Conclusion

India coalbed methane (CBM) is in the early stages of exploration. Although the coal thickness and distribution is relatively well documented, the permeability and gas content of the coals is less known. Most estimates of CBM resources are based on available geologic and reserves data from the coalfields and gas emission and gas content from the mines. By those estimates, the Cambay Basin in Gujarat, west India, is the most prospective from an area size and infrastructure position, and the Damodar Valley in eastern India is the most prospective from a coal rank and thickness basis. Together, these two areas account for most of the total CBM potential resource. Estimates of Indian CBM potential range from 400 to 4,000 billion m^3 (14 –144 Tcf).

Only seven wells have been drilled to test the CBM potential of the Cambay and Damodar areas (the only areas tested). So although some information has been acquired on the technical parameters there has been no sustained production to date. More drilling and testing will be needed to verify the commercial viability of CBM in these areas, as well as the potential for CO_2 sequestration and Enhanced CBM recovery (It is difficult to predict enhanced recovery without the benefit of information from primary production). Based on the results of the wells drilled to date a moderate potential has been defined for CO_2-ECBM recovery and CO_2 sequestration in these areas. CO_2 could be supplied from vented emissions from nearby coal fired power plants. Using information from the drilled areas, two pilot CO_2-ECBM projects with 20 km^2 areas each, could have the potential to store up to 40 million tons CO_2. This would lead a much larger project if successful.

The Government of India is encouraging CBM exploration and a new CBM licensing round is to be announced soon. The US EPA is sponsoring programs to reduce greenhouse gas as in India. Because of uncertainties in the early stages of Indian CBM exploration it will be difficult to establish a commercial CO_2-ECBM project. The United Nations Development Program (UNDP) is providing US $10.3 million to support India's efforts to minimize harmful greenhouse gas emissions. A pilot to reduce CO_2 emissions may be just as viable from an environmental basis.

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CHAPTER 6
RANKING OF SITES

6.1 Ranking of Basins

Geological assessment of the four countries identified 8 "best" prospective basins for CBM development. They are:

		Global Ranking (IEA GHG, 1998)
India:	Damodar Valley	10
	Cambay Basin	5
Poland:	Upper Silesian Basin	16
China:	Ordos Basin	13
	Qinshui Basin (N.E. China)	12
Australia:	Bowen Basin	4
	Sydney Basin	6
	Gunnedah Basin	-

Other basins were considered but eliminated due to poor CBM/CO_2 sequestration potential or lack of sufficient CBM information.

Even for these 8 basins, the amount of detailed information varied widely for the basins. Also data from selected sites in a particular basin indicate that the CBM properties between sites can be quite different. It is difficult to "average" these properties on a basin scale. IEA GHG (1998) took an excellent first step in this direction as summarized previously in Table 1.2 (Chapter 1). Compared to their evaluation, the Gunnedah Basin was considered to currently have more potential than the Clarence-Morton Basin because there is insufficient reservoir data available for the latter to consider it for a sequestration demonstration site. The same is true for India; the lack of data makes a quantitative evaluation impossible. In Poland and in the Sydney Basin, land-use competition could delay or stop approval of a sequestration site. The Gunnedah Basin is not as well characterized as the Bowen Basin. The fact that the Bowen Basin in Australia has commercial production exceeding 1 Bcf annually, whereas the three other countries have no commercial production, is the reason for ranking the Bowen Basin over the Ordos and Qinshui Basin as the best basin to evaluate for a demonstration site. This ranking may not stand in the future as more data becomes available. In order to be as impartial as possible, it was decided to independently rank the basins from the bottom up by ranking individual sites in each basin instead of relying completely on this top down analysis.

6.2 Selected Sites

Geological assessment of the four countries identified eleven potential sites for locating the CO_2-enhanced coalbed methane (ECBM) pilot plant. They are:

India:
1) Damodar Valley, Jharia Coalfield, Parbatpur Block
2) Cambay Basin, Gujarat, Mehsana Block

Poland:
3) Upper Silesian Basin, former Amoco Block, south of the town of Tychy

China:
4) Eastern Ordos Basin
5) Southern Qinshui Basin

Australia:
6) Southern Bowen Basin, Dawson River
7) Southern Bowen Basin, Moura
8) Southern Bowen Basin, Fairview
9) Southern Bowen Basin, Durham Ranch
10) Southern Sydney Basin, Camden
11) Gunnedah Basin, Narrabri

Six of the eleven sites are located in Australia. However, this does not necessarily mean that Australia is superior to China, Poland or India, but the fact that public geological data are better kept and more readily accessible in Australia than in the other three countries. It also reflects that Australia is currently the hottest area of coalbed methane activities outside the US. Still, site specific data are difficult to get, as lease owners want to keep this information confidential.

This Chapter is organized as follows: Section 6.3 is a description of a methodology for site evaluation, based on a set of factors that are essential to the success of a CO_2-ECBM project. Section 6.4 is a proposed system for scoring this set of factors for a site, followed by a summary of the data for each site in Section 6.5. Section 6.6 is an application of the scoring system to each country and identifies the site with the highest score. Section 6.7 is a ranking of the four countries, based on the "high score" site in each country.

6.3 Evaluation Methodology

Each site will be evaluated on the following five factors:

- Market Potential
- Production Potential
- CBM Resource/CO_2 Storage Potential
- CO_2 Supply Potential
- Site Infrastructure Costs (Financeability)

The development of a gas resource, which can be sold for profit is the prime economic driver of a CO_2-ECBM project. Without a ready market for the gas, there can be no project. Coalbed methane, being a gas, needs a gas trunk line to transport the gas to load centers. Once it gets there, it needs a distribution network to move the gas to the customers. If such infrastructure exists near the site, the market potential of the project is greatly enhanced.

A CO_2-ECBM process also generates environmental benefit – permanently sequestering the CO_2 in the coalbeds, thus avoiding its release to the atmosphere and can help reduce global warming and climate change. Carbon credits may be created which may have monetary value. In evaluating the market potential, we must include this benefit as well. However, its timing is not clear at this time.

A very important consideration is CBM resource potential. It can be expressed in terms of CBM concentration at the site, which determines if the payoff is worthwhile to run the risk of undertaking the project. This is measured in Bcf of gas per square mile (for comparison 10 Bcf/mi^2 is equal to 109.4 Mm^3/km^2). It is a function of the gas content in the coal and the net coal seam thickness. Closely tied in with the CBM resource potential is the CO_2 storage potential. In high volatile bituminous coal, the ratio is two sorbed CO_2 molecules for each methane molecule released. In sub-bituminous coals, up to ten molecules of CO_2 are sorbed for each methane molecule. Geology of the site is also important. The geology can be simple with good reservoir continuity and lateral communication or it can be complex with lot of faulting and folding which will greatly diminish the resource/storage potential of the site.

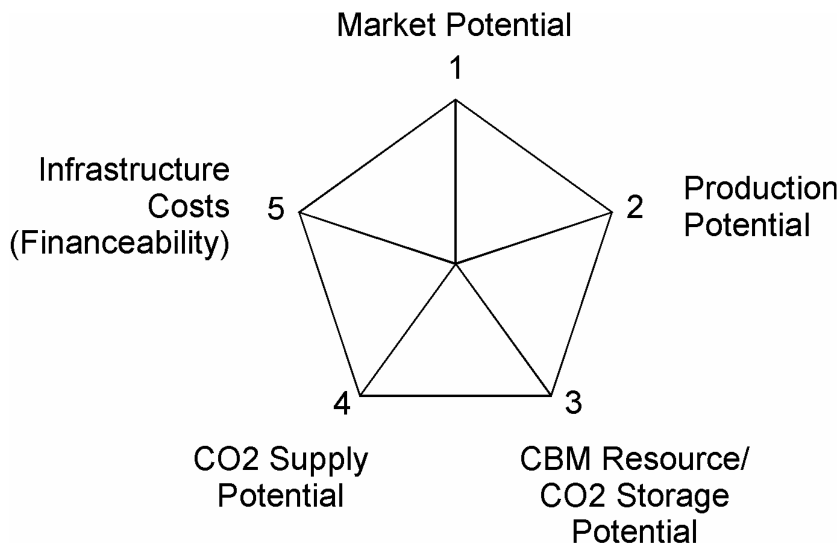
Production potential is of crucial importance. It determines how much of the resource can be produced as saleable gas. It is a function of reservoir characteristics (permeability is the key parameter) as well as the sweep efficiency.

For a CO_2-ECBM project to be viable, a large supply of inexpensive CO_2 must be made available. A likely source is CO_2 recovered from power plant flue gas. In this case, a capture cost would be incurred. An alternative is CO_2 from a fairly pure CO_2 source for example the exhaust from the reformer of a hydrogen production plant for which the costs of CO_2 capture can be greatly reduced, improving the economics of the CO_2-ECBM process. Distance of the CO_2 source from the site is a key parameter.

The last factor, which sometimes can be easily overlooked, is infrastructure cost. It is intended to capture well drilling and completion cost (relative to the San Juan Basin in the US for the same depth) as well as the regulatory and policy regime of the host country, in other words, the financeability of the project.

These five factors can be presented in a pentagon, as shown in **Figure 6.1**. The top of the pentagon is market potential, which is the economic driver of the project. The two corners at the base of the pentagon are CBM resource/CO_2 storage potential and CO_2 supply potential. These are the resource bases where production and site infrastructure can be built upon to fulfill the market needs.

Figure 6.1 The Five Factors for a Successful CO_2 – ECBM Project



6.4 Proposed Scoring System

We propose the following criteria for scoring each of the factors:

- ***Market Potential***
  - distance to connecting gas trunk line or to major load centers (3 for 0-100 km, 2 for 100-500 km, 1 for > 500 km)
  - gas demand, is it well developed? (1 to 3 for low, medium and high demand)
  - wellhead gas price (4 for US \$ 2-4/Mcf (\$0.071 – 0.141/m^3), 2 for US \$1-2/Mcf (\$0.035 – 0.071/m^3), 0 for < US \$ 1/Mcf (<\$0.035/m^3))
  - environmental pollution, is it a serious problem in the country? (1 to 3 for low, medium and high, to capture any likely credits for sequestering CO_2)

- ***Production Potential***
  - permeability (3 for > 20 md, 2 for 5-20 md, 1 for 1-5 md), 0 <1 md Less than 1 md is a showstopper and the site will not be considered.
  - sweep efficiency (2 for homogeneous reservoir and 1 for inhomogeneous reservoir)

- ***CBM Resource/CO_2 Storage Potential***
  - site gas potential in Bcf/sq. mile (4 for > 20 (>219 Mm^3/km^2), 3 for 10-20 (109 – 219 Mm^3/km^2), 2 for 3-10 (33 – 109 Mm^3/km^2), 1 for <3 Bcf/sq. mile (<33 Mm^3/km^2))
  - CO_2 storage potential

(2 for a 10:1 ratio and 1 for a 2:1 ratio of molecules of CO_2 sorbed/molecule of CH_4)
- Geology
  (2 for simple and 1 for complex)

- ***CO_2 Supply Potential***
  - distance of CO_2 source from site

    (3 for < 50 km, 2 for 50-200 km, 1 for > 200 km)
  - quality of CO_2, pure or flue gas

    (2 for pure source, 1 for flue gas)
  - size of the CO_2 supply, adequate for commercial project

    (2 for > 4000 t/d, 1 for < 4000 t/d)

- ***Site Infrastructure Costs***
  - regulatory regime, is it clear and acceptable i.e. is the project financeable

    (1 to 3 for poor, fair and excellent)
  - cost level above reference U.S. cost to capture drilling costs w.r.t depth and general cost structure
    (4 for 0 to +25%, 3 for +25 to +40%, 2 for +40 to +100% and 1 for >100%)

The score for each factor is calculated from the sum of its components and then normalized to 1. Then, the scores for each of the five factors are multiplied together to calculate a "site score":

Site score = Market Potential score x Production Potential score x CBM Resource/CO_2 Storage Potential score x CO_2 Supply Potential score x Site Infrastructure Cost score x 1000.

Finally an "Uncertainty factor" is estimated, which will discount the site score to reflect uncertainties in the estimates. We propose to weigh the uncertainty factor towards drilling density around the site (0.5 for 1-3 wells, 0.7 for 4-10 wells, 0.9 for 11-20 wells and 1 for >20 wells). As more data become available, we can use more sophisticated technique such as Monte Carlo simulation to assess uncertainties in the estimate. An "adjusted site score" is then calculated where:

Adjusted Site score = Site score x the uncertainty factor.

This scoring method uses an additive approach to calculate each factor score followed by a multiplicative approach to calculate the site score. We feel that this approach better captures the essence of the evaluation process, as all five factors are inter-related and essential to the success of the project. The scoring system is first applied to select the best site from each country, and then they are used to rank the country for a CO_2 – ECBM demonstration pilot.

6.5 Summary of Site Data

INDIA:

Site 1:	**Mehsana block, Cambay Basin**
Area	Essar site ~400 km^2, CBM potential 82 Gm^3 (2.9 Tcf)
Drilling History	3 wells drilled by Essar
Geology	Simple, with minor faulting
Gas Potential	~18 Bcf/mi^2 (197 Mm^3/km^2), 2.9 Tcf (82 Gm^3) over 400 km
CO_2 Storage Capacity	CO_2:CH_4 ratio 2:1 by volume
Permeability	1 – 3 md
Gas Injectivity	Fair, based on limited information on permeability
Sweep	Good, consistent seams
Gas Market	established gas demand 200 km from Hazira-Bijaipur-Jagdishpur (BHJ) National Pipeline
CO_2 Sources	Gandhinager coal fired power plants ~ 60 km away
CO_2 Processing/Transport	Flue gas

Site 2:	**Parbatpur block, Jharia Coalfield – Damodar Valley**
Area	The Oil and Natural Gas Corporation (ONGC) site 20 km^2, total undeveloped area in Jharia about 200 km^2
Drilling History	4 wells drilled by ONGC
Geology	Simple, maybe some compartmentation
Gas Potential	in the 20 Bcf/mi^2 (219 Mm^3/km^2) range
CO_2 Storage Capacity	CO_2:CH_4 ratio 2:1 by volume
Permeability	1 – 5 md range, no published data
Gas Injectivity	Fair, thick Permian age bituminous coal, intruded by Cretaceous age igneous dikes
Sweep	Good in area drilled by ONGC, faulting and dikes may affect sweep
Gas Market	No gas infrastructure 550 km from HBJ National Pipeline
CO_2 Sources	Chandrapura and Santadh coal fired power plants ~ 25 km away
CO_2 Processing/Transport	Flue gas

Poland:

Site 1:	**Former Amoco block – Upper Silesian Basin**
Area	Total area about 486 km^2 (120,000 acres)
Drilling History	6 test wells, 8 coreholes
Geology	Densely explored coal basin, structurally complex
Gas Potential	6 Bcf/mi^2 (66 Mm^3/km^3), based on basin average
CO_2 Storage Capacity	CO_2:CH_4 ratio 2:1 by volume
Permeability	1-5 md
Gas Injectivity	Fair, based on limited information on permeability
Sweep	No data
Gas Market	Near industrial complex of Katowice, Gas pipeline runs through the area
CO_2 Sources	Number of coal fired power plants and steelworks
CO_2 Processing/Transport	Flue gas

CHINA:

Site 1:	**Arco block, Hedong Prospect, Eastern Ordos Basin**
Area	~5000 km^2
Drilling History	9 wells drilled by Arco, total 15 wells on Hedong Prospect
Geology	Complex, with faults and compartmentation
Gas Potential	~11 Bcf/mi^2 (120 Mm^3/km^2), average
CO_2 Storage Capacity	CO_2:CH_4 ratio 2:1 by volume
Permeability	1 – 40 md
Gas Injectivity	Good
Sweep	No assessment
Gas Market	No gas infrastructure, not an industrial area Gas trunkline 200 km north
CO_2 Sources	Limited CO_2 sources
CO_2 Processing/Transport	Likely flue gas

Site 2:	**CUCBM/CNPC site – South Qinshui Basin**
Area	Site about 550 km^2, CBM 100 Gm^3
Drilling History	CUCBM/CNPC drilled 25 wells in South Qinshui
Geology	Simple, thick continuous seam around the site
Gas Potential	In the 16 Bcf/mi^2 (175 Mm^3/km^2) range
CO_2 Storage Capacity	CO_2:CH_4 ratio 2:1 by volume
Permeability	1 – 5 md range
Gas Injectivity	Fair
Sweep	Good
Gas Market	One of most industrialized region in China Access pipeline should be short to reach load centers
CO_2 Sources	Yangcheng and Yauqual coal fired power plants within 50 km
CO_2 Processing/Transport	Flue gas

AUSTRALIA:

Site 1:	**Dawson River – South Bowen Basin**
Area	~ 242 km^2, CBM 58 Gm^3
Drilling History	34 CBM wells drilled, number of these stimulated and production tested
Geology	Simple, with extensive database
Gas Potential	~22 Bcf/mi^2 (240 Mm^3/km^2), 58 Gm^3 over 242 km
CO_2 Storage Capacity	CO_2:CH_4 ratio 2:1 by volume
Permeability	2 – 19 md, mean ~ 5 md
Gas Injectivity	Good
Sweep	Some evidence of compartments, comprehensive data not available
Gas Market	High gas growth in New South Wales (NSW) and Queensland Well served by pipeline, extension planned
CO_2 Sources	Gladstone power plant ~ 150 km
CO_2 Processing/Transport	Flue gas

Site 2:	**Moura site – South Bowen Basin**
Area	Site about 550 km^2, CBM 100 Gm^3
Drilling History	27 wells drilled
Geology	Simple, with extensive database
Gas Potential	In the 16 Bcf/mi^2 (175 Mm^3/km^2) range
CO_2 Storage Capacity	CO_2:CH_4 ratio 2:1 by volume
Permeability	1 – 3 md
Gas Injectivity	Fair
Sweep	Good
Gas Market	High gas growth in NSW and Queensland Well served by pipeline, extension planned
CO_2 Sources	Gladstone power plant ~ 150 km
CO_2 Processing/Transport	Flue gas

Site 3:	**Fairview – South Bowen Basin**
Area	Site ~ 693 km^2 CBM 65 Gm^3
Drilling History	22 CBM wells drilled
Geology	Simple, with extensive database
Gas Potential	~9 Bcf/mi^2 (98 Mm^3/km^2), 65 Gm^3 over 693 km
CO_2 Storage Capacity	CO_2:CH_4 ratio 2:1 by volume
Permeability	Poor data, large implied from production testing of cavity completed wells
Gas Injectivity	Good
Sweep	No information for assessment
Gas Market	High gas growth in NSW and Queensland Well served by pipeline, extension planned
CO_2 Sources	Gladstone power plant ~ 300 km
CO_2 Processing/Transport	Flue gas

Site 4:	**Durham Ranch – South Bowen Basin**
Area	Site about 691 km^2, CBM 65 Gm^3
Drilling History	9 CBM appraisal wells drilled
Geology	Limited seismic and geophysical well logging
Gas Potential	In the 9 Bcf/mi^2 (98 Mm^3/km^2) range
CO_2 Storage Capacity	CO_2:CH_4 ratio 2:1 by volume
Permeability	No data, implied high
Gas Injectivity	Fair
Sweep	Good
Gas Market	High gas growth in NSW and Queensland Well served by pipeline, extension planned
CO_2 Sources	Gladstone power plant ~ 350 km
CO_2 Processing/Transport	Flue gas

Site 5:	**Camden – South Sydney Basin**
Area	Site ~ 275km^2 CBM 25.5 Gm^3
Drilling History	12 CBM appraisal wells drilled
Geology	Limited seismic and geophysical well logging
Gas Potential	~9 Bcf/mi^2 (98 Mm^3/km^2), 25.5 Gm^3 over 275 km
CO_2 Storage Capacity	CO_2:CH_4 ratio 2:1 by volume
Permeability	Variable, 1 md in some areas, 12-36 md reported from CBM wells
Gas Injectivity	Good
Sweep	No information for assessment, variable between seams
Gas Market	High gas growth in NSW and Queensland Well served by pipeline, extension planned
CO_2 Sources	main power plants west and north of Sydney basin 50 - 100 km
CO_2 Processing/Transport	Flue gas

Site 6:	**Narrabri – Gunnedah Basin**
Area	Site
Drilling History	15 CBM wells drilled, 9 stimulated
Geology	Good definition at margins
Gas Potential	~ 12 Bcf/mi^2 (131 Mm^3/km^2) range
CO_2 Storage Capacity	CO_2:CH_4 ratio 2:1 by volume
Permeability	18 – 36 md from well tests
Gas Injectivity	Good
Sweep	No data available
Gas Market	High gas growth in NSW and Queensland Pipeline recently constructed to region
CO_2 Sources	2 coal fired power plant ~ 150 km
CO_2 Processing/Transport	Flue gas

6.6 Ranking of Sites in Each Country

The scoring sheets for the eleven sites are included in the Appendix I. The results of the site evaluation for each country are summarized as follow:

6.6.1 India

	Cambay Basin Gujarat, Mehsana Block	**Damodar Basin Jharia Coalfield Parbatpur Block**
Market Potential	0.69	0.54
Production Potential	0.60	0.60
CBM Resource/CO_2 Storage Potential	0.75	0.75
CO_2 Supply Potential	0.86	0.86
Site Infrastructure Costs	0.43	0.29
Site Score	114	59
Uncertainty Factor	0.5	0.5
Adjusted Site Score	57	30

Between the two sites selected for India, the Mehsana Block scores higher than the Parbatpur Block (site score of 114 versus 59). Both sites have reasonable permeability, thick continuous coal seam and a good supply of CO_2 from the nearby coal fired power plants. However, the gas demand in Gujarat is better developed than in Bihar and also because Gujarat is a major petroleum producing state in India, CBM drilling and stimulation support is more easily accessible in the Cambay Basin than in the Damodar Basin. In addition, there is concern that Coal India may be reluctant to let CO_2 be pumped into their coal seams in the Jharia Coalfield. We assign a high uncertainty factor of 0.5 to each site, as each site has only three test wells drilled to date.

Hence, the Mehsana Block in the Cambay Basin is the recommended site for India.

6.6.2 Poland

	Upper Silesian Basin Former Amoco Block
Market Potential	0.85
Production Potential	0.40
CBM Resource/CO_2 Storage Potential	0.50
CO_2 Supply Potential	0.86
Site Infrastructure Costs	0.71
Site Score	104
Uncertainty Factor	0.7
Adjusted Site Score	73

Only one site is selected for Poland. It is the former Amoco Block in the Upper Silesian Basin, south of the town of Tychy. We score the site at 104. The area has good gas market potential, as it is close to major population and the large industrial complex of the Katowice region. The CBM can be easily connected to markets as a number of medium and high-pressure gas trunk lines runs through the area. CO_2 can be supplied from coal-fired power plants and steelworks close by. The area has good infrastructure for CBM drilling and stimulation. The basin is a densely explored coal basin. However, its geology is structurally complex. A total of six test wells has been drilled at the site. There is little site information available. We have to rely on basin average for the evaluation.

The former Amoco Block in the Upper Silesian Basin is recommended as the site for Poland.

6.6.3 China

	Ordos Basin Eastern Border	**Qinshui Basin Southern part**
Market Potential	0.69	0.85
Production Potential	0.60	0.40
CBM Resource/CO_2 Storage Potential	0.63	0.75
CO_2 Supply Potential	0.57	0.86
Site Infrastructure Costs	0.71	0.86
Site Score	106	186
Uncertainty Factor	0.9	0.9
Adjusted Site Score	95	168

Two sites have been selected for China, the Eastern Ordos Basin and the Southern Qinshui Basin. No specific site area is noted in the Eastern Ordos. Unless some companies move out, most areas of the Hedong Coalfield have been or will be occupied by foreign companies for the CBM cooperative exploitation under the Production Sharing Contracts (PSC). The site for Southern Qinshui Basin will be near the CUCBM existing pilot site. The Southern Qinshui Basin site scores higher than the Eastern Ordos site (site score of 186 versus 106). The reasons for the lower score for the Ordos are:

- The site is in a more remote area of China. Hence, the gas market is less developed and site costs are generally higher.
- Supply of CO_2 to the site is a major problem, as few industries are located there.

On the other hand, The Qinshui Basin is well explored. CUCBM has drilled 16 wells and CNPC 9 wells in south Qinshui. CO_2 supplies are plentiful. For example, the Yangcheng Power Plant, (the biggest in Shanxi Province), Changzhi Iron and Steel Company, Yangquan Power Plant and some fertilizer plants are in the vicinity of the site. The advantage for the Ordos basin site is its higher production potential, as there is expectation that sweet spots with high permeability may be found.

Overall, we recommend the South Qinshui Basin as the site for China.

6.6.4 Australia

A total of six sites have been selected for Australia, four in the Southern Bowen Basin, one in the South Sydney Basin and one in the Gunnedah Basin.

	Southern Bowen, Dawson River	**Southern Bowen, Moura**	**Southern Bowen, Fairview**	**Southern Bowen, Durham Ranch**
Market Potential	0.62	0.62	0.62	0.62
Production Potential	0.60	0.40	0.40	0.40
CBM Resource/ CO_2 Storage Potential	0.88	0.75	0.63	0.63
CO_2 Supply Potential	0.71	0.71	0.57	0.57
Site Infrastructure Costs	0.86	0.86	0.86	0.86
Site Score	198	113	75	75
Uncertainty Factor	1.0	1.0	1.0	0.7
Adjusted Site Score	198	113	75	53

Of the four sites in the Southern Bowen Basin, Dawson River scored the highest, at 198. The Dawson River and Moura sites are close together, while the Fairview and Durham Ranch sites are further to the southwest. The area has good market potential, as gas consumption has been growing rapidly in New South Wales and Queensland. It has good CBM drilling and stimulation infrastructure. For CO_2 supply, the Fairview and Durham Ranch sites are at a disadvantage to the Dawson River and Moura sites, as the Gladstone coal fired power plant is further away. The reasons for the higher Dawson River score are an indicated permeability of 5 – 20 md and a much better CBM resource concentration of around 22 Bcf/sq. mile (241 Mm^3/km^2).

	Southern Sydney, Camden	**Gunnedah Basin, Narrabri**
Market Potential	0.62	0.62
Production Potential	0.40	0.60
CBM Resource/CO_2 Storage Potential	0.63	0.75
CO_2 Supply Potential	0.86	0.71
Site Infrastructure Costs	0.57	0.86
Site Score	75	170
Uncertainty Factor	0.9	0.9
Adjusted Site Score	68	153

For the Camden site in Southern Sydney Basin, the major impediment is competing land use where the area might be better used for urban development or national parks. This will probably prohibit it from consideration as a pilot plant site. The Narrabri site in the Gunnedah Basin also scores quite high, at 170. The major reason for it is the high permeability of 18 – 36 md measured from test wells.

Overall, the Dawson River site in the Southern Bowen Basin is recommended as the site for Australia.

6.7 Country Ranking

The four recommended sites from each country are summarized below:

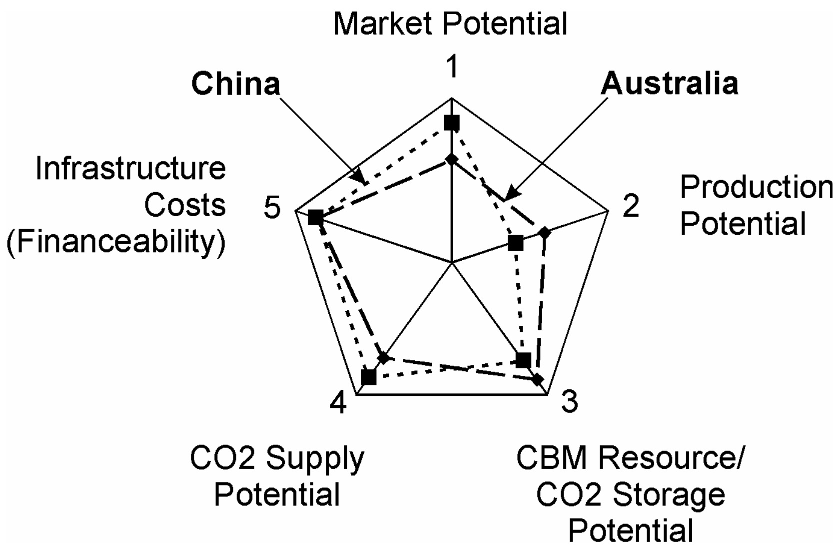
	Australia **Southern Bowen, Dawson River**	***China*** **Southern Qinshui, CUCBM Site**	***Poland*** **Upper Silesian, Former Amoco**	***India*** **Cambay Gujarat, Mehsana Block**
Market Potential	0.62	0.85	0.85	0.69
Production Potential	0.60	0.40	0.40	0.60
CBM Resource/ CO_2 Storage Potential	0.88	0.75	0.50	0.75
CO_2 Supply Potential	0.71	0.86	0.86	0.86
Site Infrastructure Costs	0.86	0.86	0.71	0.43
Site Score	198	186	104	114
Uncertainty Factor	1.0	0.9	0.7	0.5
Adjusted Site Score	198	168	73	57

Australia has the highest score followed by China, Poland and India. The India score is low because of a lower gas market potential, as the gas market infrastructure is not well developed and a lower infrastructure cost rating (financeability). Drilling cost is estimated to be 30% higher than Australia and Poland. However, the major impediment for the low infrastructure cost rating is a bureaucratic regulatory regime which can be quite time consuming. In addition, the Cambay Basin is the least explored basin for CBM among the four basins, hence the high uncertainty factor. The high risk factor is a very dominant factor in deciding against India. Poland also scores quite well, but it is hindered by a low production potential and low CBM resource potential. One of the reasons for that is because site information is lacking and we have to rely on basin average data for evaluation.

Comparing China and Australia, the strengths of the China site are its high gas demand potential and CO_2 supply potential, while the site infrastructure costs (financeability) are comparable. The strengths of the Australia site are its production potential and CBM resource potential. This can be illustrated in the pentagon, as shown in **Figure 6.2**. In other words, the Australia site offers the best potential for technical performance while the China site is the best site where the technology is most needed.

In summary, we rank the four countries in descending order as Australia, China, Poland and India. ***The scores of the Australia and China sites are very close. In addition to the technical performance and market potential consideration for the two countries, there is the developed and developing country perspect which would impact on the potential funding sources. We consider both sites have merits and should be further evaluated for pilot plant design and economics.***

Figure 6.2 Comparing the Australia and China Sites



6.8 References

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CHAPTER 7
DESIGN FOR TECHNICAL/COMMERCIAL DEMONSTRATION SITE FOR CO_2-ECBM

7.1 Technical Approach

The overall objective of the project is to install a commercial CO_2 sequestration/enhanced methane hydrocarbon gas production operation. To insure that the process can be implemented successfully from both a technical and economic viewpoint, a staged process must be used. Three major stages will be discussed in this document as summarized in **Table 7.1.** After these three stages, sufficient information would be available to expand the project to a field-wide scale. This section outlines these three stages. Details are included later in this chapter.

Table 7.1. Major Pilot Stages

Stage	Description	Number of Wells
1	Micro-Pilot Testing	1 Injection/Production
2	5-Spot Pilot Testing	4 Injection / 1 Production
3	9-Pattern Testing	16 Injection / 25 Production

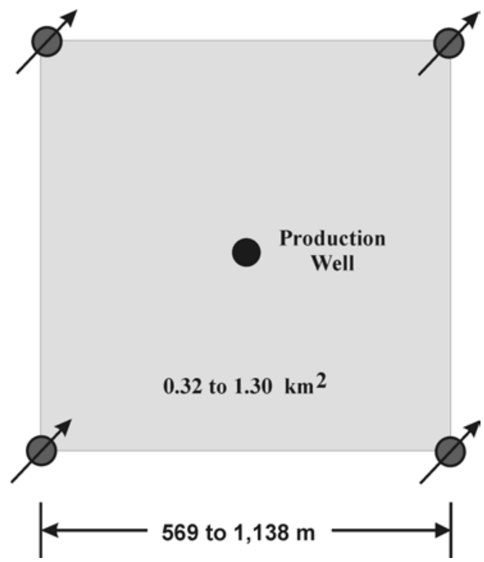
During the first stage of the project, the field of interest is studied to select an optimum location for the pilot. This study includes both geologic and reservoir engineering efforts to quantify the continuity, geometry, and properties of the coal seams based upon available data. A formation evaluation test well is then drilled to obtain data to improve the estimates of reservoir properties. Cores are taken and logs are measured. The core samples are used to quantify the gas content, storage capacity, and other coal properties as discussed later. The permeability of the coal seams is quantified with well tests. If the permeability is sufficient, the well is completed and used as a micro-pilot test well. If permeability is insufficient, another location for the micro-pilot test must be found.

During the micro-pilot test, the well is stimulated and placed on production to obtain coal seam gas and water productivity information, fluid composition data, and production and shut-in pressure data. CO_2 is injected and allowed to be sorbed into the coal. The well is returned to production to quantify the effect of the CO_2 upon the reservoir properties and to measure the gas composition. The gas composition data is evaluated to predict the volume of methane displaced by the CO_2.

The final effort during Stage 1 is to evaluate all of the data and to use the evaluation to predict the behavior of a Stage 2 five well pilot under both CO_2 injection alone and under a combination of CO_2 and N_2 injection. This information is used to design the size of the pilot injection pattern. Stage 1 projects are relatively inexpensive and would provide the much needed data on the effectiveness of CO_2 injection. Two or more stage 1 projects could be run concurrently if time is of essence, to identify the optimum location of the pilot. If the results of Stage 1 project conclude that potential sequestration and production volumes are sufficient to meet technical and economic requirements, the project proceeds to Stage 2.

The goal of Stage 2 is to install, operate, and evaluate a 5-spot injection well pattern. A typical pattern is illustrated in **Figure 7.1**. The pattern is sized so that the production response of the reservoir to injection can be quantified within a twelve-month time frame. The data collected

Figure 7.1 Typical 5-Spot Pilot Pattern



from the 5-spot pilot is used to predict the behavior of a 9-pattern operation that would be installed during Stage 3.

The Stage 1 micro-pilot test well will be converted to an injection well during Stage 2. A second well will be drilled at one of the injection well locations. This well would be tested to insure that sufficient permeability exists to justify the remainder of the injection and production wells. This second well will also be used to perform a second micro-pilot test during which both CO_2 and N_2 would be injected. These micro-pilot data are used to assist with the interpretation of the 5-spot data. At the conclusion of the second micro-pilot test, the production well and the remaining two injection wells will be drilled and completed. The production well will be placed on production as soon as possible to obtain pre-injection gas and water production, pressure, and test data. Surface facilities for injection and production are installed. Flue gas injection begins with portable flue gas generators and continues for a year. At the end of the injection period, production continues for a final one month to complete data acquisition for the project.

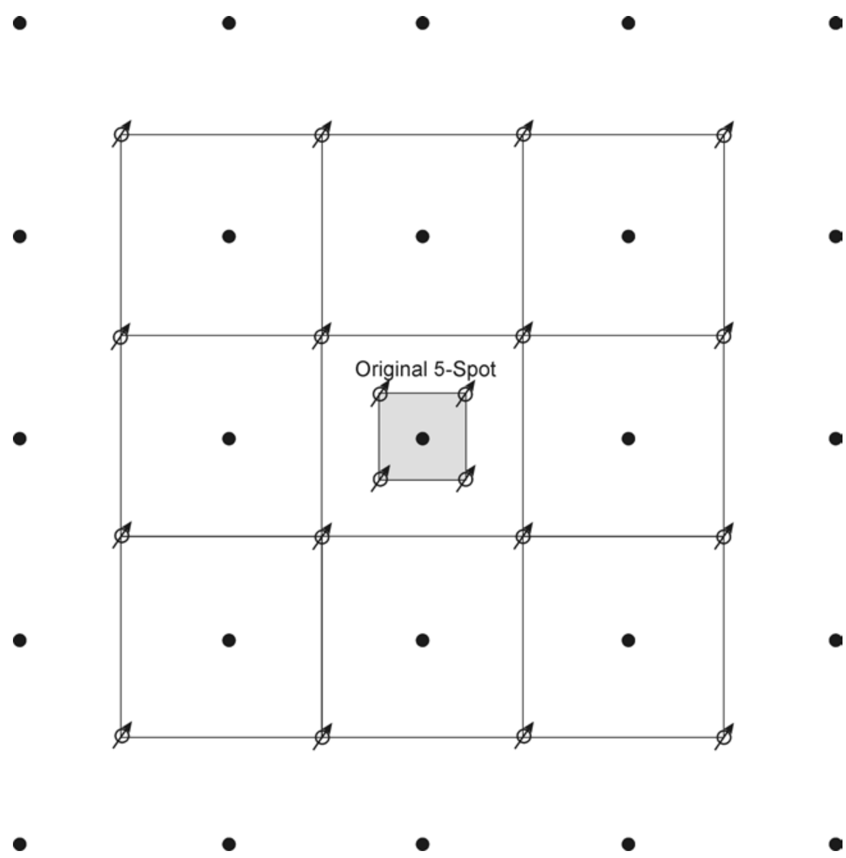
An array of three pressure monitoring wells should be sited both inside and outside the pattern based on cleat, stress and directional permeability data, if it is available. These add some extra control points for the simulations and history matching.

One important aspect of the 5-spot effort is to determine the optimum mix of CO_2 and N_2 to inject into the coal seams. Therefore, the mix will be varied during the project by adding CO_2 from a purchased source.

The important information gained from the 5-spot pilot includes the sweep efficiency (proportion of the hydrocarbons displaced), the increase in hydrocarbon production rates, and the optimum composition of the injected gases. These data as well as the pressure behavior are matched with a comprehensive multicomponent coal gas reservoir simulator. Once matched, the calibrated simulation model is used to predict the behavior of a large-scale project. The predicted behavior is evaluated both technically and economically to determine if the larger-scale effort is warranted.

The larger-scale project is installed around the existing pilot but with a much larger well spacing. Possible well spacing scales are on the order of 0.32 to 1.3 km^2 (80 to 320 acres) and depend upon the optimum size predicted by the calibrated simulation model. Eight additional patterns are installed to create the 9-pattern flood illustrated in **Figure 7.2**. Production wells are included outside of the injection wells to maximize hydrocarbon productivity. The 9-pattern test includes 41 total wells, 16 injectors and 25 producers. The original four injection wells in the 5-spot pilot are converted to observation wells. The original production well continues to produce. This large-scale effort would continue for two to five years. A decision to expand the project beyond the 9-pattern test would be based upon the sequestration and production performance of the project.

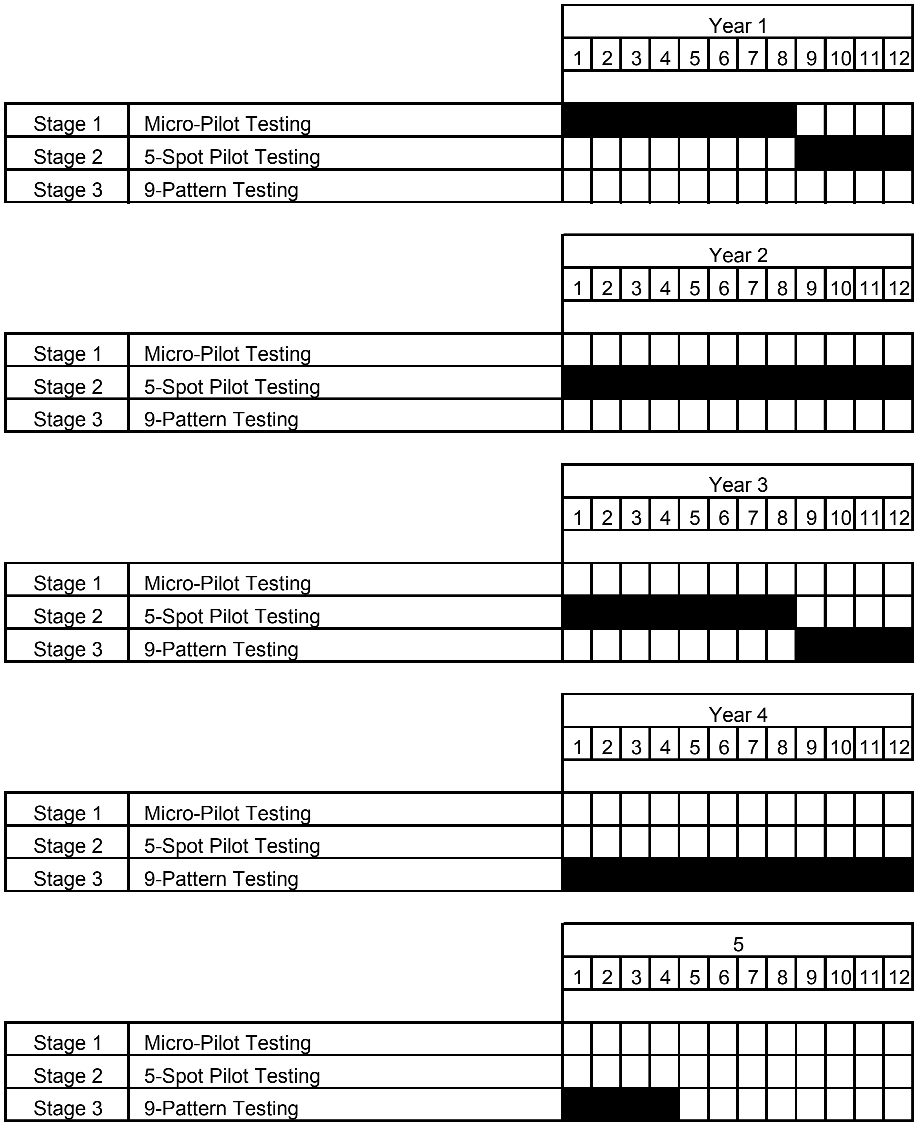
Figure 7.2 9-Pattern Flood Geometry



More detailed descriptions of these stages are included in the following sections. The most important aspect of a project of this nature is to collect sufficient data to properly evaluate the technical and economic performance of the project and to make correct decisions concerning progression from one stage to the next.

The overall timing to this project is 4.3 years as illustrated in **Figure 7.3** based on the assumption that there are no gaps between each stage. At the end of year 5, assuming success, Stage 3 would become a commercial operation.

Figure 7.3 Overall Project Timing



This operation plan is a detailed plan suitable for both sites in Australia and China. For the Dawson River coal gas field in Australia, eleven coal seams have been penetrated at depths between 421 and 835 m. Average total coal thickness is 20 m. The reservoir are normally pressured with gas contents generally exceeding 11 cm^3/g. Gas content is similar to storage capacity. Estimates of permeability in some seams have been as great as 4.8 md. Average gas production rates are 8,500 m^3/D (300 Mcfd) with 32 m^3/D (200 STB/D) of water. Total gas production is roughly 113,000 m^3/D (4 MMcfd). Production well costs are roughly $A 500,000 ($US 300,000).

For the Qinshui Basin in Shanxi Province of China, China United Coalbed Methane Co. Ltd. (CUCBM) has drilled 25 wells in the basin of which 16 wells are in the southern part of the basin. Burial depth ranges from 300 to 1,000 meters and initial gas content 12 to 25 m^3/t. The coal is a high-rank anthracite at Jincheng. Stable daily outputs of CBM were observed from the pilot wells at the Anze and Tunlin blocks of Qinshui Basin, with a high rate of 16,300 m^3/day at one well. On the basis of the pilot data, the area contains 100 Gm^3

of CBM within the 550 km^2 block. The properties of this CBM field are characterized by high rank coal, thick and stable coal seams distribution, moderate burial depth, relatively simple structure, good sealing conditions, high gas content and good permeability. Production well costs are roughly $US 400,000.

7.2 Stage 1, Micro-Pilot Testing

Stage 1 is composed of four sub stages as summarized in **Table 7.2**. Stage 1.1 is required to select the optimum location for the pilot. The purpose of Stage 1.2 is to accurately quantify the reservoir properties. Stage 1.3, the micro-pilot test itself is required to quantify the coal natural fracture permeability, to insure that sufficient CO_2 injectivity is present, to determine the hydrocarbon sweep efficiency, and to determine the effect of CO_2 injection upon the reservoir properties and behavior. The data collected during the micro-pilot test is evaluated during Stage 1.4 and used to predict the behavior of a 5-spot pilot. If the project proceeds to the 5-spot stage, the formation evaluation well becomes an injection well.

Table 7.2 Stage 1, Micro-Pilot Testing Sub Stages

Stage	Description
1.1	Field Review
1.2	Formation Evaluation Well Drilling and Evaluation
1.3	Micro-Pilot Testing
1.4	Data Analysis and 5-Spot Pilot Design

7.2.1 Stage 1.1. Field Review

In the event that the pilot will be performed in an undeveloped area, only a geologic evaluation will be performed. If the project is to be performed in a developed coal gas field, Stage 1.1 is performed in three tasks designed to:

1. evaluate the geology of possible pilot locations,
2. obtain quantitative estimates of the reservoir properties that will affect sequestration and enhanced recovery, and
3. select the optimum pilot size and injection fluid composition.

The purpose of the geologic evaluation is to determine the optimum location for the pilot. Of most interest are three characteristics; coal seam continuity between injection and production wells, minimal communication with continuous permeable sandstones or other rock types, and isolation of one coal interval for the pilot. While sandstones are discussed in this section, the same approach applies regardless of the rock type of possible permeable conduits other than coal. A good ECBM site should avoid any high permeability sandstone or low angle or bedding plane shear zones to avoid “short circuiting” the CO_2. If available, open hole log data are reviewed in several possible locations for the pilot. Stratigraphic cross-sections are constructed that illustrate the vertical geometry of the coal and interbedded and surrounding rocks and correlate the individual coal and sand bodies (or other rock types) between wells. Maps that illustrate the thickness of individual coal and sand bodies are also prepared. Without well penetrations, the geologic evaluation must be based upon surface geology and known characteristics of the area. Optimum location selection based upon surface geologic is imprecise as coal deposits can vary greatly in limited distances from the outcrop.

One of the important considerations for the pilot concerns continuity of the coal seams and sandstone between injection and production wells. Clearly, the coal seams must be continuous so that displaced hydrocarbon gases can flow through the reservoirs and be produced. To evaluate the degree of enhanced recovery and sweep efficiency in a reasonable period, the pilot must be isolated in one primary coal interval that is laterally continuous between wells. However, the presence of continuous permeable sandstones can cause problems. Sequestration concerns alone do not preclude the presence of permeable gas-bearing sands. In areas where the sandstones do not outcrop, the sandstones will be excellent sequestration sites. However, under the combination of sequestration and enhanced methane production, gas-bearing continuous sandstones can become conduits for CO_2 between injection and production wells causing CO_2 to breakthrough to producing wells.

7.2.2. Stage 1.2, Formation Evaluation Well Drilling and Evaluation

In the event that Task 1 concludes that a pilot installation is feasible, the first well of the pilot will be drilled at one of the corner locations of the pilot as illustrated in **Figure 7.1**. This well will be designed to quantify reservoir properties needed for an evaluation of the pilot and to predict the future performance of a 5-spot and large-scale sequestration/enhanced recovery project. Mavor et al. (1992) summarizes many of the formation evaluation procedures.

The coal seams will be cored and logged during this task. A complete characterization of the coal is performed to obtain the reservoir property estimates summarized in **Table 7.3**. These properties are of interest to both gas recovery and CO_2 sequestration. It is also necessary to core and perform analyses of the inorganic rocks above, between, and below the coal seams. **Table 7.4** summarizes the measurements to be performed in the inorganic rocks. The primary purpose of the inorganic rock measurements is to quantify the storage and flow properties of the interbedded rocks.

The formation evaluation well will be a vertical well drilled to 15 meters (50 feet) below the deepest coal seam of interest. The bottom 15 meters is required for sufficient rat hole for logging tools and to provide a sump while producing the well. For cased hole completions, wells are often drilled with a 200-mm (7.875-inch) bit and cased with 139.7-mm (5.5-inch) casing. Core bit sizes match the bit diameter. A 88.9-mm (3.5-inch) diameter core is most common when using conventional coring equipment.

The general data collection plan depends upon the relative location of coal seams and permeable inorganic rock types. If the permeable inorganic rocks are located immediately above the coal seams, these rocks must be cored. If the coal interval is capped with impermeable claystone, coring can begin immediately above the coal seams. The following plan is based upon an impermeable cap rock existing.

1. Drill to within 2 meters (6 feet) above the top of the shallowest coal interval of interest.

2. Core through cap rock, the coal interval, and 1 meter into the underlying rock with a conventional, 10-meter (30-foot) PVC-lined core barrel.

3. Retrieve the core barrel to surface and place coal core samples in desorption canisters for gas content and gas composition measurements.

4. Continue coring the coal and inorganic rocks through the interval of interest.

5. Retrieve the core barrels to surface and place coal core samples in desorption canisters for gas content and gas composition measurements.

6. Drill to the planned total depth and measure a wireline log suite

The coring and logging operations are performed by petroleum industry service companies using standard equipment. The details of the analysis procedures are discussed in Mavor and Nelson (1997). Core desorption measurements must be started on location by specialists in this technology to determine the in-situ gas content of the coal and the composition of the gas. These measurements are completed in a laboratory over a period of one to three months. These data when combined with open-hole log data and the geologic studies will allow accurate estimates of the gas-in-place volume and composition as well as the sequestration capacity.

Table 7.3 Summary of Required Coal Gas Reservoir Property Estimates.

Property	Units	Data Source
Geometry		
Individual Coal Seam Top Depth	m	Wireline Logs and Cores
Individual Coal Seam Bottom Depth	m	Wireline Logs and Cores
Coal Seam Thickness	m	Wireline Logs and Cores
Reservoir Temperature, Pressure, and Permeability		
Average Temperature	^oC.	Wireline Logs and Well Tests
Initial Pressure	kPa(a)	Well Tests
Effective Permeability to Gas	md	Well Tests
Effective Permeability to Water	md	Well Tests
Coal Properties		
Equilibrium Moisture Content	wt. %	Eq. Moisture Measurements
Sample Moisture Content	wt. %	Proximate Analysis
Ash Content (moist)	wt. %	Proximate Analysis
Sulfur Content (moist)	wt. %	Lab Measurements
Organic Fraction Density (dry)	g/cm^3	Data Regression
Inorganic Fraction Density (dry)	g/cm^3	Data Regression
Gas Content, Composition, Sorption Time		
In-Situ Sorbed Gas Content (moist with ash)	scf/ton	Desorption Measurements
Sorbed Gas Composition	mole %	Desorbed Gas Analysis
Coal Diffusivity	sec^{-1}	Desorption Measurements
Gas Storage Capacity		
Methane Storage Capacity vs. Pressure	cm^3/g	Isotherm Measurements
CO_2 Storage Capacity vs. Pressure	cm^3/g	Isotherm Measurements
N_2 Storage Capacity vs. Pressure	cm^3/g	Isotherm Measurements
Thermal Maturity, Organic and Mineral Composition		
ASTM Coal Rank Classification	-	Lab Measurements
Calorific Value (moist, mineral-matter-free)	Mj/kg	Lab Measurements
Mean-Maximum Vitrinite Reflectance (in oil)	%	Lab Measurements
Vitrinite Content (mineral-matter-free)	vol. %	Lab Measurements
Inertinite Content (mineral-matter-free)	vol. %	Lab Measurements
Liptinite Content (mineral-matter-free)	vol. %	Lab Measurements
Mineral Matter Composition	vol. %	Lab Measurements
Natural Fracture Properties		
Relative Permeability	-	Lab Measurements
Porosity	vol. %	Lab Measurements

Table 7.4 Summary of Inorganic Rock Core Analyses.

Property	Units	Data Source
Permeability to Air	md	Routine core analyses
Helium Porosity	vol. %	Routine core analyses
Water Saturation	vol. %	Routine core analyses
Grain Density	g/cm^3	Routine core analyses
Rock Composition	wt. %	X-Ray Diffraction Measurements

The open-hole logs recommended for evaluation are summarized in **Table 7.5**. This suite is required to estimate the properties of the coal and the inorganic rocks.

Table 7.5 Planned Open-Hole Log Suite.

Log	Purpose
Deep and Medium Induction Resistivity	Sandstone Water Saturation
Shallow Resistivity	Invaded Zone Water Saturation
Micro-Resistivity	Invasion – Permeability Presence
Natural Gamma Ray	Inorganic Rock Clay Content
Natural Gamma Ray Spectrum	Inorganic Rock Clay Type
Bulk Density	Coal Inorganic Content and Inorganic Rock Porosity
Neutron Porosity	Inorganic Rock Clay Content and Gas Saturation
Caliper	Wellbore Diameter

The most important log data will be bulk rock density to determine the thickness and inorganic content of the coal, micro-resistivity to determine the depths of permeable intervals, and gamma ray for correlation with other logs. The porosity and resistivity data are used to determine the properties of inorganic rocks.

At the completion of the logging operations, steel casing is run to the total depth of the well. This casing will be cemented in place to allow isolation of the coal intervals of interest.

7.2.3 Stage 1.3, Micro-Pilot Testing

The micro-pilot approach to coalbed reservoir evaluation has three primary goals. The first goal is to accurately measure data while injecting into and producing from a single well. The second goal is to match the measured data with a comprehensive coal gas reservoir simulation model to obtain estimates of reservoir properties and sorption behavior. The third goal is to use the calibrated simulation model to predict the behavior of a larger scale pilot project or full field development.

The data that must be measured includes the injection rates, surface and bottom-hole pressure and temperature while injecting carbon dioxide, the surface and bottom-hole pressure and temperature during shut-in periods, and the surface and bottom-hole pressure and temperature, gas and water production rates, and gas composition during producing periods.

When casing is run and cemented in place, the near-well coal natural fracture system becomes severely damaged. Perforating alone is not effective in connecting the wellbore to the natural fracture system. Acid stimulation is not effective either. Hydraulic fracture stimulation is required. Prior to stimulation:

1. Measure a cased-hole cement bond, gamma ray, collar log to determine bond quality, zone isolation, and to correlate with other logs.

2. Perforate the coal interval of interest with conventional jet perforating charges.

As this well will eventually be an injection well, a stimulation is required that will not result in significant height growth out of the coal interval. A water/proppant stimulation treatment is recommended. Typically, these stimulations consist of pumping water containing low proppant concentrations of 120 to 240 kg/m^3 (1 to 2 pounds per gallon) at high rates such as 10 m^3/minute (60 barrels per minute). Proppant size is often 800 to 420 µm (20/40 mesh). A design specific to the coal seam and rock conditions at the site will be developed to ensure adequate stimulation without height growth The effective fracture length will be less than 10 meters (30 feet) and should allow the well to be produced in an undamaged manner.

Once stimulation is completed, a water injection/falloff test is required to estimate the reservoir pressure, effective permeability to water and the stimulation efficiency. Alternatively this test could be performed in an open hole before casing is installed. The procedure for this test is similar to the following.

1. Move in and rig up a completion rig.

2. Set up a small water tank and fill with 12 m^3 (75 barrels) of filtered drinking water containing 1% potassium chloride (KCl).

3. Run into the well with tubing and clean out frac sand that remains in the wellbore.

4. Trip out of the well with the tubing.

5. Pick up a bottom-hole injection assembly that consists of the following items from the bottom up:

   a. wireline reentry guide
   b. 3-m (10-ft) pup joint
   c. bottom no-go nipple
   d. 3-m (10-ft) perforated spacer tube
   e. upper no-go nipple
   f. tubing-set injection packer

6. Trip in the hole with the bottom-hole assembly on tubing and set the packer 12 m (40 ft) above the top perforation.

7. Rig up slick line equipment and trip in the hole with a self-contained memory electronic pressure / temperature and set the transducer in the bottom no-go nipple. The transducer should be capable of measuring 0.14 kPa (0.02 psi) pressure changes and storing data points every 15 seconds.

8. Rig up surface pumping equipment and injection rate and surface pressure recording equipment.

9. Inject the filtered water at a rate not to exceed 20 liters/minute (5 gal/minute) for a period of eight hours. Total injection volume is 9.6 m^3 (60 barrels).

10. Near the end on the injection period, rig up slick equipment and a plug in a lubricator. Run in the well with the plug and set the plug in the upper no-go nipple. Cease injection after the plug is set and maintain surface pressure of at least 1,500 kPa (220 psig). Trip out of the well with the slick line equipment.

11. Leave the well shut-in for twice the injection period duration or 16 hours.

12. Trip in the well with slick line equipment and recover the plug and transducer.

13. If the pressure data is suitable for analysis, trip out of the well with the injection string. If not rerun the test.

After the test is completed, tubing will be rerun into the well. A permanently installed surface recording pressure/temperature transducer is run on a nipple in the tubing-casing annulus. The nipple should be ported to read annulus pressure. The transducer is connected to the surface via wireline banded to the tubing and protected with collar protectors. A computer at the surface records temperature and pressure at programmable time increments. The transducer should be capable of monitoring pressure changes of 0.14 kPa (0.02 psi). A rod pump and a pump jack are installed for artificial lift.

Although equipment specifications depend upon reservoir pressure and depth, a wellhead rated to 21,000 kPa (3,000 psi) is often installed to with stand pressure during gas injection. A polish rod BOP should be included so that shut-in tests can be performed without surface leaks. A typical completion diagram is illustrated in **Figure 7.4**. **Figure 7.5** illustrates a wellhead diagram

The well will be produced for 30 days with artificial lift as necessary to obtain gas and water productivity data and produced gas samples for composition determination. The production period is followed with a shut-in test. The data measured during the shut-in period are evaluated to obtain pressure and permeability estimates prior to gas injection.

Following the shut-in test, the pump and rods are removed from the well. CO_2 is purchased and trucked to location. CO_2 is periodically injected over a period of a week or so until the desired CO_2 volume is injected through the perforations. A typical CO_2 injection volume is on the order of 23,000 m^3 of vapor per meter of coal. CO_2 will be injected relatively rapidly below fracture pressure gradient using hydraulic fracturing equipment. After injection, there will be a soak period of at least the same duration to allow the sorbed and free gas composition to equilibrate in the reservoir.

Once the soak period is completed, the well will be returned to production for 30 days to determine the well's productivity and the composition of the produced gas. The production test is followed with a final shut-in period to obtain pressure and permeability estimates after injection. These data are evaluated to estimate the CO_2 sequestration potential and the enhanced hydrocarbon gas recovery that should result from a 5-spot pilot. The 5-spot pilot is designed with well testing technology, reservoir engineering calculations, and simulation models.

Figure 7.4 Production Well Completion Diagram

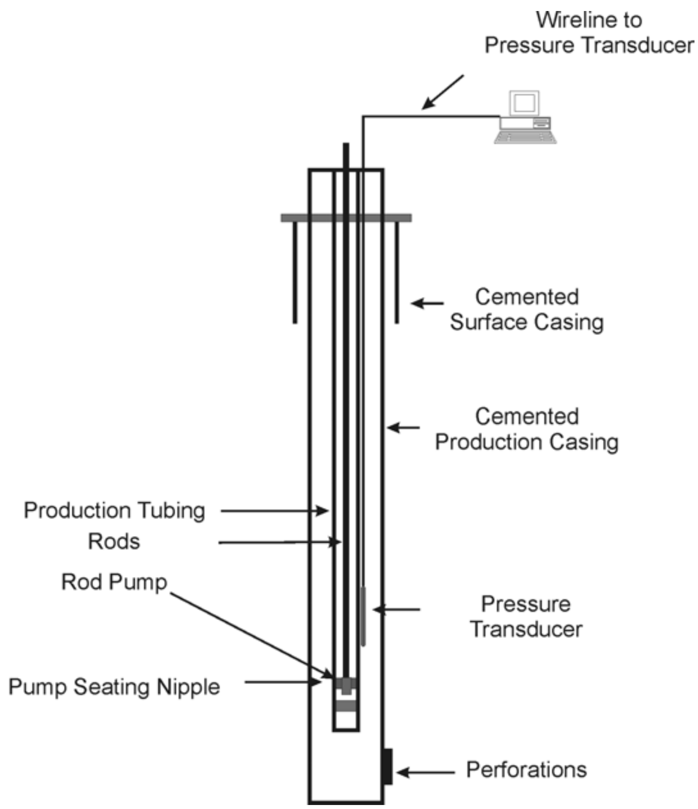
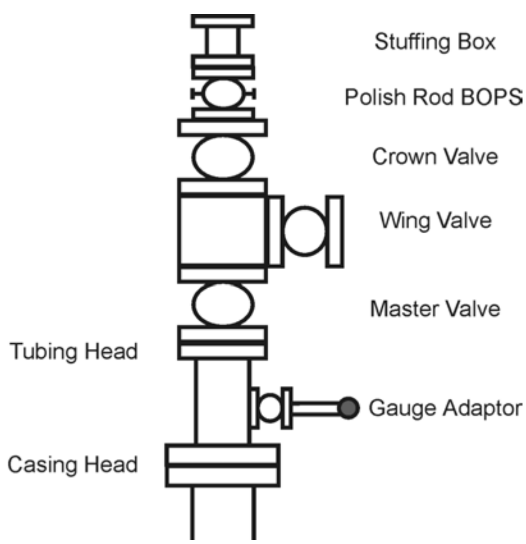


Figure 7.5 Production Wellhead Diagram



An example computation of 5-spot pattern size design for CO_2 injection alone is as follows. Over 60% of the pilot area will have to be contacted by CO_2 during the life of the pilot for an obvious production increase. The size estimate can be based upon the area required to sequester a given volume of CO_2. This area can be calculated with the following relationship.

$$A = \frac{Q_i}{10^6 h \overline{\rho}_c \overline{G}_s} \tag{1}$$

where:

A *gas storage area, km²*
Q_i *cumulative CO_2 injection volume, standard m^3*
h *thickness of the coal interval accepting injection, m*
$\overline{\rho}_c$ *average in-situ coal density at the average in-situ rock composition, g/cm^3*
$\overline{G}_s$ *average in-situ storage capacity of the injected gas, cm^3/g*

Typical CO_2 injection rates are on the order of 20,000 to 60,000 m^3/D (0.7 to 2 MMcfd) into four injection wells, equating to 5,000 m^3/D to 15,000 m^3/D (0.2 to 0.5 MMcfd) per well. For the maximum case, over a twelve-month period, a total of $5.2(10^6)$ m^3 (182 MMcf) of CO_2 will be injected into each well. Suppose that the in-situ storage capacity of CO_2 is 26.8 cm^3/g (860 scf/ton) and that the coal interval is 4 m (13 feet) thick. The area around each injection well required to store the year's injection volume is 0.0371 km^2 (9.2 acres). Therefore, for CO_2 injection alone, we would have to use a pilot pattern area of 0.06 to 0.08 km^2 (15 to 20 acres) to obtain a measurable productivity increase for the production well.

The actual pilot operation will include injection of a mixture of N_2 and CO_2. The pilot design requires reservoir geometry estimates, methane, N_2, and CO_2 sorptive capacities of the coal, and the effective permeability to gas and water. The sorptive capacity estimates will be based upon measured CH_4 and CO_2 sorption isotherm data obtained from laboratory measurements performed on the coal samples used for the desorption measurements.

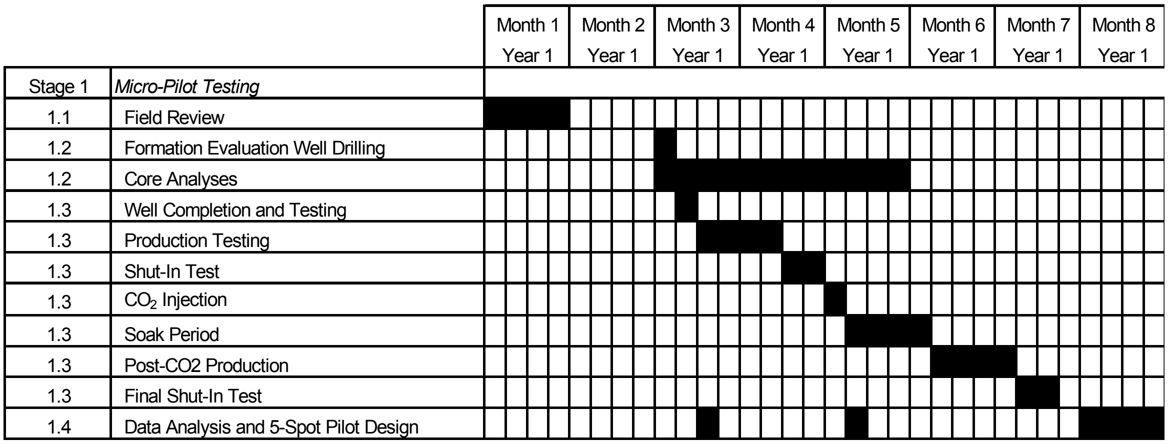
The pilot design requires a multicomponent coal gas reservoir simulator. The simulator is used to model 5-spot pilot hydrocarbon recovery as a function of injection rate, injection gas composition, and pattern area until an optimum solution is found. The pattern size will be similar to but larger than that expected for CO_2 injection alone.

The decision to continue to a 5-spot pilot is based upon the range of the performance estimates predicted by the simulator. If the gain in hydrocarbon productivity is sufficient, the project continues to Stage 2.

7.2.4 Micro-Pilot Timing

Stage 1 can be completed within an eight-month time frame as illustrated by **Figure 7.6**. The initial field review can be completed within one month. Once the well location has been selected, permits must be acquired for drilling. The permitting process can be quite lengthy. **Figure 7.6** assumes that one month is required however; this length could be from one to six months depending upon the location of the project. The well can be drilled, cored, logged, and cased in one week. Core analyses begin at the well site and usually require three months to complete all measurements. The stimulation and initial testing will require one week to complete. The production test is scheduled for one month and is followed by a two-week shut-in test. CO_2 injection will require one week to complete followed by a one-month soak period. Post-CO_2 production requires one month and is followed by a final two-week shut-in test. Final data analysis may require a month to complete.

Figure 7.6 Stage 1, Micro-Pilot Time Requirements



7.2.5 Stage 1, Summary

The micro-pilot design will allow determination whether a 5-spot pilot can succeed early in the life of the project. If the injectivity is too low for the project, the project can be terminated and costs will be minimized. In the event that injectivity and productivity are sufficient, the design will result in the data required to calibrate a coal gas reservoir simulator to properly predict the behavior of future expanded pilot projects or full-field development.

The data that must be measured include the injection rates, surface and bottom-hole pressure and temperature while injecting carbon dioxide, the surface and bottom-hole pressure and temperature during shut-in periods, and the surface and bottom-hole pressure and temperature, gas and water production rates and gas composition during producing periods.

7.3 Stage 2, 5-Spot Pilot Testing

Once the micro-pilot test has been evaluated and confirmed that sufficient permeability and gas-in-place volume is present to justify project expansion, installation of the pilot can begin. The goal of the 5-spot pilot is to demonstrate that carbon dioxide sequestration and enhanced gas recovery is possible. A product of the pilot will be complete specifications of the technology required to perform large-scale projects. The specifications will include those for a flue gas collection and treatment module, a compression module, and a gas production module.

The 5-spot installation procedure includes a step-by-step process as summarized in **Table 7.6**. The second well is drilled at the location of one of the injection wells. This well is completed in the same manner as the first well. A second micro-pilot test is performed to collect data required to predict N_2 and CO_2 injection behavior. The 5-spot installation can be terminated at this point if injectivity or productivity are insufficient for the process.

Table 7.6 Stage 2, 5-Spot Testing Sub Stages

Stage	Description
2.1	Second Well Drilling and Completion
2.2	Second Well N_2/CO_2 Micro-Pilot Testing
2.3	Conversion of First Two Wells to Injection Wells
2.4	Production Well Drilling and Completion
2.5	Pre-Injection Production
2.6	Remaining Injection Well Drilling and Completion
2.7	Surface Facility Construction
2.8	Injection and Production
2.9	Final Testing
2.10	Analysis and Expansion Design

The first well is converted to an injection well. The remaining wells are then drilled and completed. The production well is placed on production as soon as possible to maximize the length of pre-injection production history. The surface facilities are constructed. Injection begins for a period of 12 months. A final one-month production period completes data collection. The final analysis of all data is completed at the end of the project. The data is matched with a reservoir simulation model. The calibrated model is used to forecast recovery of a large-scale project. A decision to expand the project can be made at this time.

7.3.1 Stages 2.1 and 2.2, Second Well Installation and Evaluation

The second well drilled for the 5-spot pilot must be carefully evaluated to insure that sufficient permeability is present to continue the project. For this reason, the second well should be located at the opposite corner of the 5-spot pattern. The second micro-pilot test is conducted to obtain reservoir data concerning the behavior of N_2 and CO_2 injection. Pure gases will be used for this injection to simplify data analysis. The data from this test will be used to calibrate the simulation model that will be used to evaluate the 5-spot behavior. The steps for Stages 2.1 and 2.2 are summarized in **Table 7.7**.

The second well is drilled, logged, and cased in the same manner as the first well with the exception that coring is not performed unless additional coal samples are desired. Although not done here, if the budget allows, it is recommended that core should be taken from each well for gas content and isotherm measurement. Such background data is very valuable when trying to model and understand the production data.

Once stimulation is completed, an injection-falloff test will be performed to obtain data to estimate the reservoir pressure, the effective permeability to water and the degree of stimulation. This test will be performed with the same procedures as for the first test.

Table 7.7 Stage 2.1 and 2.2 Steps

Step	Description
1	Drill a new well at the opposite corner of the 5-spot from the first well.
2	Drill to the planned total depth and run open-hole logs.
3	Run and cement casing.
4	Stimulate with a water/proppant hydraulic fracture treatment.
5	Conduct an injection-falloff test
6	Place the new well on production for 30 days.
7	Conduct a shut-in test
8	Inject a nitrogen-carbon dioxide mixture.
9	Shut-in the well for a soak period.
10	Conduct a 30 day post-injection production test.
11	Conduct a final shut-in test.

At the conclusion of the test, tubing, a surface recording bottom-hole pressure/ temperature transducer and a rod pump will be run into the well. A wellhead rated to 21,000 kPa (3,000 psi) will be installed. The production completion and wellhead schematics for this well are the same as for the first well, **Figures 7.4 and 7.5**.

The well will be produced for 30 days with artificial lift as necessary to obtain gas and water productivity data and produced gas samples for composition determination. We will follow the production period with a shut-in test to obtain pressure and permeability estimates prior to flue gas injection.

We plan to inject a mixture of N_2 and CO_2 to simulate flue gas. The use of the pure gas species will reduce the need for flue gas cleanup and extensive core analyses and will simplify analysis of the data. The gases will be injected relatively rapidly below fracture pressure gradient using hydraulic fracturing equipment. After injection, there will be a soak period of two to four weeks to allow the sorbed and free gas composition to equilibrate in the reservoir.

Once the soak period is completed, the well will be returned to production for 30 days to determine the well's productivity and the composition of the produced gas. Data acquisition will be finalized with a shut-in test. These data will be evaluated and used to predict the behavior of the 5-spot pilot.

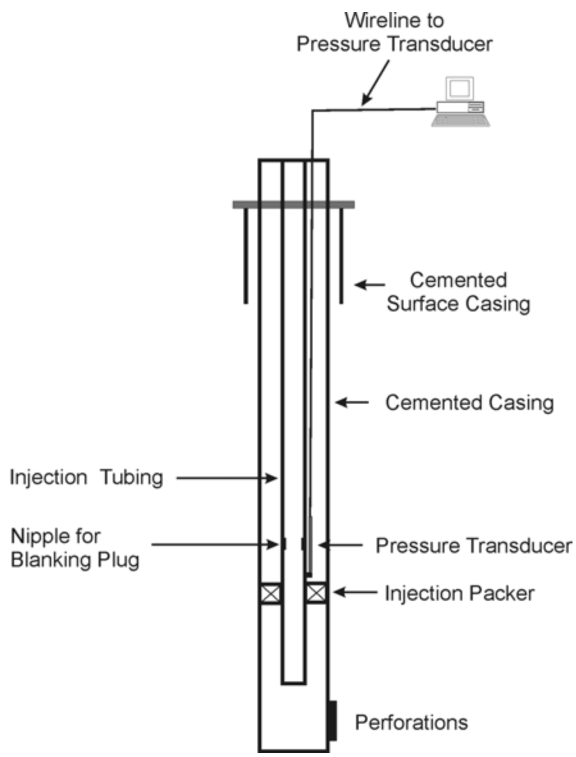
The decision to continue installation of the 5-spot will be based upon the permeability estimates and the injectivity of N_2 and CO_2. If sufficient permeability does not exist, the project can be terminated at this point.

7.3.2 Stage 2.3, Conversion of First Two Wells to Injection Wells

If the project continues, the next step will be to work over the first two wells to injection wells. This stage requires removing the downhole production equipment, installation of an injection packer, reinstallation of a surface-recording, bottom-hole pressure/temperature transducer, and replacing the production wellhead equipment with an injection wellhead rated to 21,000 kPa (3,000 psi).

Once the workover is completed on each well, a nitrogen injection test is performed to insure that the well can be used as an injector. While injection will be expected to be possible because of the previous test, injectivity should be confirmed prior to spending money on new wells and surface facilities. Once the nitrogen injection test is completed, a tubing plug will be run into the wells to isolate the pressure gauge from the surface. The wells will then be used as pressure observation wells until injection begins. **Figure 7.7** illustrates a schematic of the injection wells.

Figure 7.7 Injection Well Completion Diagram



7.3.3 Stages 2.4 through 2.6, Well Installation

The production well will be the third well drilled for the 5-spot. This well will be drilled, logged, completed, stimulated, and tested in the same manner as for the first well, taking account of previous data and the final design for the 5-spot trial. A permanently installed downhole pressure transducer and a rod pump will be included. **Figure 7.4** illustrates the completion diagram. The wellhead used for the production well will be similar to that for the first well, **Figure 7.5**, with the exception that the pressure rating will not have to be as great as since N_2 or CO_2 will not be injected into this well. While hydraulic fracturing, a tree saver should be used to protect the wellhead equipment.

The well will be placed on production with controlled artificial lift prior to the start of injection to obtain background production data. Gas and water production rates and operating pressure conditions will be carefully monitored. Gas composition will be measured with a gas chromatograph and gas samples. Water samples will be taken periodically for composition measurements. A shut-in test should be performed prior to the start of injection to obtain pressure, effective conductivity to gas and water and stimulation effectiveness estimates.

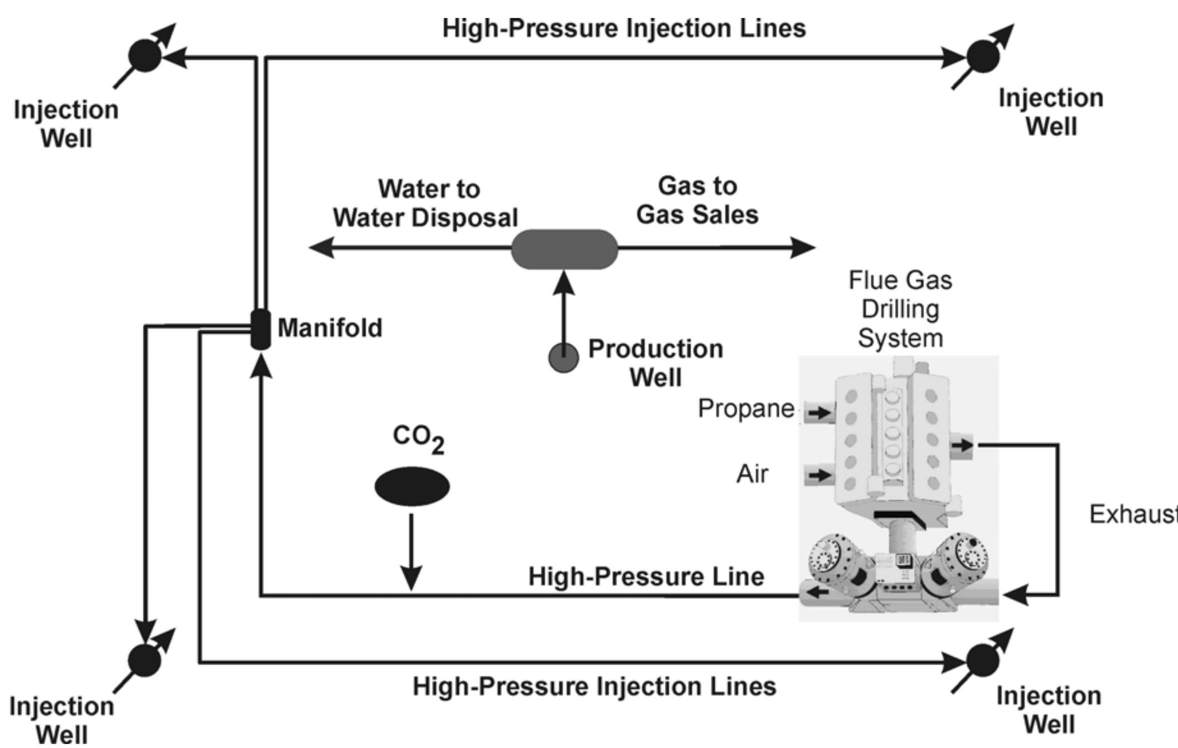
The remaining two injection wells will be drilled, logged, and cased. The wells will be completed by perforating the casing but without stimulation. Water injection falloff tests will be conducted after perforating to insure that injection is possible. If not, the wells will be stimulated with high rate water injection without proppant. Once injectivity is sufficient, an injection packer, tubing, plug seating nipple, and a bottom-hole pressure transducer will be run into each well. Wellheads rated to 21,000 kPa (3,000 psi) will be installed.

A tubing plug will be run into the well on slick line to isolate the pressure transducer from the surface. All four of the injection wells will be used as pressure monitoring wells until injection begins.

7.3.4 Stage 2.7, Surface Facility Installation

The surface facilities consist of a variety of items illustrated in **Figure 7.8**. These items include a flue gas generation / compression system, the injection lines, and the production facilities. Since this pilot is not likely to be located immediately adjacent to a flue gas source, a portable temporary source will be used for the pilot.

Figure 7.8 Schematic of Surface Facility Layout.

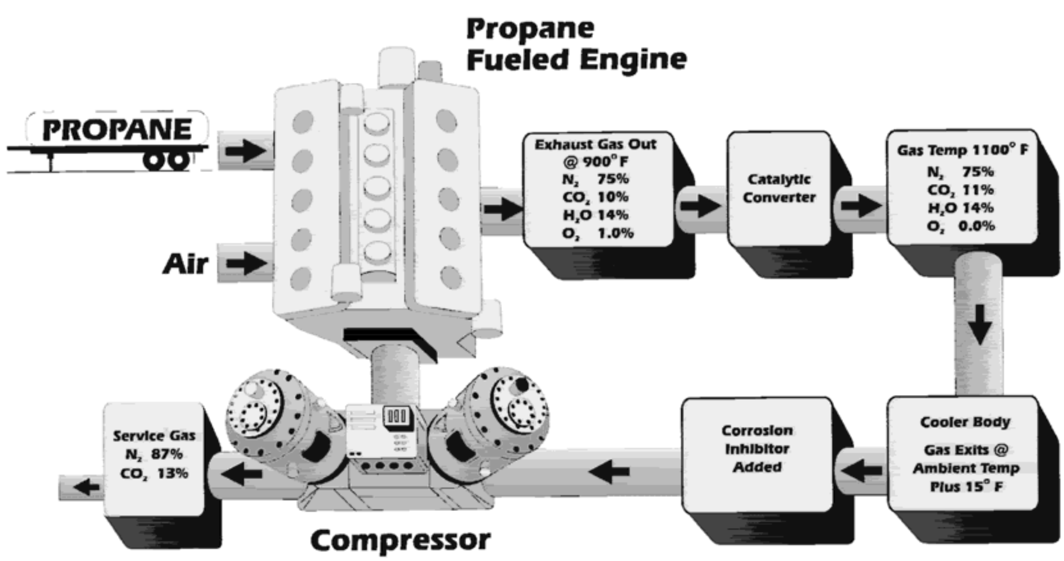


Flue gas will be generated with a portable flue gas compressor used in underbalanced gas drilling applications. A schematic of this equipment is illustrated in **Figure 7.9**. The compressor runs on propane and air. The exhaust gas is passed through a catalytic converter that removes all oxygen and then passed through a cooler that removes most of the water and cools the exhaust to 8 ^{o}C above ambient temperature. The exhaust is compressed to either 9,600 kPa(g) (1,400 psig) or 13,800 kPa(g) (2,000 psig). The composition is 87% N_2 and 13% CO_2. The delivery rate is between 59,000 and 82,000 m^3/D (2 to 2.9 MMcfd) corresponding to an injection rate of 15,000 to 20,000 m^3/D (0.5 to 0.73 MMcfd) per injection well. The smaller unit is the more likely candidate for a pilot.

To investigate changes in the composition of the injection gas, CO_2 will be added from a purchased source. This source will be liquid when delivered to location. The CO_2 will be vaporized after compression. The mixture of N_2 and CO_2 will enter a manifold that will direct the gases to the injection wells.

The injection rates at each well will be monitored with a standard gas orifice meter. The injection rates may vary between injection wells under a constant gas pressure condition, and this may have to be controlled. Flow rate entering the manifold must also be monitored with an additional meter run. The injection gas composition will also be monitored. At the production well, water flows out of the tubing and into water lines to a tank. Water rates will be measured with positive displacement or turbine meters. Gas is produced up the casing-tubing annulus and enters a flow line to a standard two phase separator. Gas rates are monitored with orifice meters. This equipment is available commercially. Gas composition will be monitored with a gas chromatograph and gas samples. Water composition will be monitored by resistivity and sample analysis.

Figure 7.9 Schematic of a Flue Gas Compressor



Gas can be utilized on location or sold if the project is performed in a developed field. Water will enter a water gathering system if in a developed field. If not, water will be trucked from location to a disposal site as necessary.

The site should be electronically instrumenting so that all data is collected in a central computer system that can be remotely monitored. The monitored data will include the following.

1. Injection well bottom-hole and surface pressure and temperature.

2. Gas injection rates at each well and exiting the high-pressure compressor.

3. Injection gas composition.

4. Production well bottom-hole and surface pressure and temperature.

5. Gas and water production rates.

6. Produced gas and water composition.

A variety of supplementary data such as separator pressure and temperature conditions, as well as pressure and temperature conditions at important surface locations should also be monitored.

7.3.5 Stage 2.8, Flue Gas Injection

Once construction is completed, testing of each surface facility module must be performed to remove operating problems and to insure that the data collection systems are functioning properly. Temporary shutdown of injection during the project will be beneficial, as the shut-in pressure behavior at the injection wells will allow estimates of the effect of the injected gas upon the reservoir properties. There may be planned shut-in periods as well.

Because of the complexity of this project, 24-hour manned coverage will be required. These personnel will be qualified to operate and trouble shoot as much of the equipment as possible.

Once the background production data are measured, injection of the desired mix of CO_2 and N_2 will begin. Injection will likely begin with the exhaust gas composition but will likely be varied depending upon the amount of N_2 in the produced gas stream. If N_2 production becomes excessive, CO_2 use will be increased and exhaust decreased. The injection rates may be decreased in this situation also. The variation in injected gas composition will result in valuable data concerning variation effects upon sequestration and enhanced recovery volumes. Injection is expected to continue for twelve months. All data discussed in the surface facilities section will be collected and evaluated during this time.

The rate of CO_2 usage will vary as the desired mix varies. There may be periods of pure CO_2 injection. The rate of CO_2 usage can be computed from Equation 2 for the desired injection gas composition.

$$q_C = q_e \frac{x_{TC} - x_{eC}}{1 - x_{TC}} \tag{2}$$

where:

q_C *CO_2 injection rate, m^3/D*

q_e *exhaust injection rate, m^3/D*

x_{TC} *mole fraction of CO_2 in the injection stream*

x_{ec} *mole fraction of CO_2 in the exhaust stream*

If the average composition of the injection gas is 25% CO_2 over the life of the project, the CO_2 injection rate is 16% of the exhaust gas injection rate. Over a period of one year, this volume would amount to 876,000 m^3 of CO_2. The liquid volume to be delivered to location would be 2,000 m^3 (2,100 metric tons) including losses.

7.3.6 Stage 2.9, Post Injection Testing

At the conclusion of the injection period, production monitoring will continue for thirty days to determine if the produced gas composition and rate or water production rates change. Data acquisition will be completed with a final shut-in test to determine the average reservoir pressure, the effective permeability to gas and water, and the stimulation efficiency at the end of the pilot.

7.3.7 Stage 2.10, Data Analysis

One of the important aspects of this data is to properly archive, store, and distribute all data to interested parties. A web site may be utilized for this. The amount of data will be enormous and this will be a time consuming task

Evaluation of the pilot behavior will be performed with well testing technology, reservoir engineering calculations, and reservoir simulation models. The goal of the analyses is to improve understanding of the processes, document the enhanced recovery and sequestration volumes, and to evaluate the economics of the process.

Data analysis must continue throughout the pilot. A final effort to history match the measured data with a reservoir simulator to create a calibrated reservoir model will be required. The model will allow computation of the following items.

1. Hydrocarbon sweep (displacement) efficiency

2. Carbon dioxide injection front locations

3. Nitrogen distribution

4. Pressure distribution

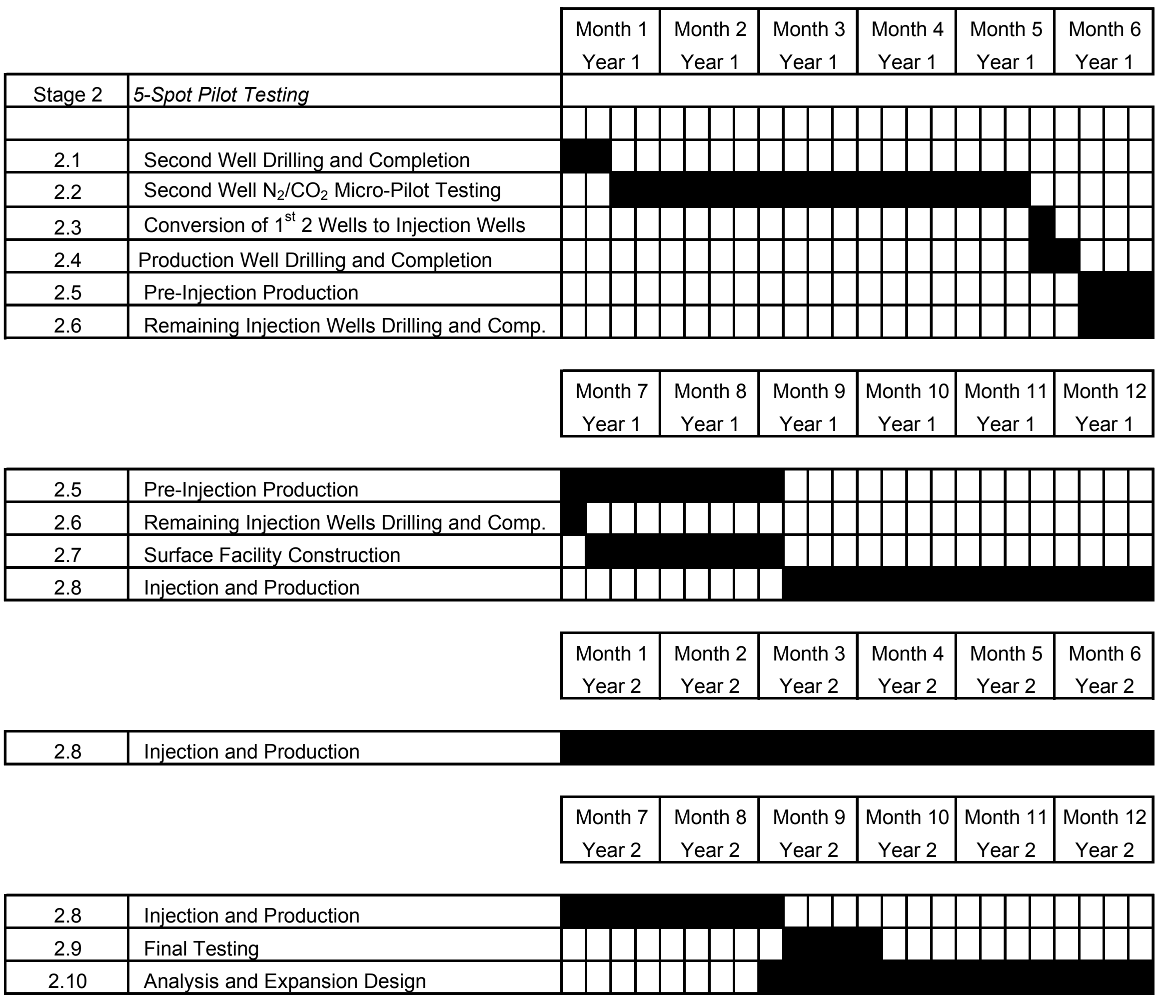
5. Optimum CO_2 – N_2 ratio for maximum hydrocarbon recovery and economic return

The model will also be used to predict the expected hydrocarbon production rates and CO_2 sequestration volume under large-scale implementation of the technology. Should the process appear to have value, the project will proceed to a larger scale stage.

7.3.8 Stage 2, Timing

The expected timing for this stage is illustrated in **Figure 7.10**. The entire stage will require roughly two years to complete. The second well can be drilled and completed in two weeks. Micro-pilot testing requires 17 weeks to complete. The workovers of the first two wells and drilling of the production well can be performed simultaneously within two weeks. Three months of background production behavior can be achieved. Surface facility construction can be completed in two months. Injection and production continues for twelve months. Final testing requires one month. Data analysis may require as many as four months to complete.

Figure 7.10 Stage 2, 5-Spot Pilot Time Requirements



7.3.9 Stage 2, Summary

The 5-spot pilot design will allow determination whether a 5-spot pilot can succeed early in the life of the project. If the injectivity is too low at the second well location, the project can be terminated and costs will be minimized. In the event that injectivity and productivity are sufficient, the design will result in the data required to determine if expansion to a larger scale development effort is both technically and economically warranted.

7.4 Stage 3, 9-Pattern Testing

It should be clear from the 5-spot pilot test whether a larger scale effort is warranted. If so, an additional eight patterns can be installed surrounding the 5-spot pilot. The ability to expand the pilot hinges on the ability to deliver injection fluids (flue gas, CO_2, etc.) to the site without excessive transportation compression requirements. This is a very important distinction between a field demonstration for a CBM primary operation and ECBM. The size of CO_2 source requires that a commercial demonstration be much larger than a 5-well field pilot. Another important component will be to operate the project without generating additional greenhouse gas emissions. This section begins with a discussion of source and transportation options, and then discusses installation of the 9-pattern expansion itself.

7.4.1 CO_2/N_2 Sources For Large-Scale Projects

There will be three possible sources for CO_2 for these projects, natural sources, coal-fired power plants and natural gas treating plants. Natural gas-fired turbine power plants are also a possibility however; the emissions from turbines are much less.

Burlington Resources Corporation (McGovern, 1998) has been using CO_2 that was produced from naturally occurring subsurface deposits, compressed, and shipped to within 50 km (30 miles) of their San Juan Basin, New Mexico, pilot. Use of naturally occurring CO_2 does not assist in reducing atmospheric emissions and is not an option for sequestration.

Byproducts from gas treating plants that remove H_2S and CO_2 from produced natural gas are liquids that range in composition from 5% H_2S / 95% CO_2 to 94% H_2S / 6% CO_2. (Wichert, 1999). These liquids are usually injected into underground formations for disposal but have not been utilized for coal gas enhanced recovery.

Coal-fired power plants are the largest source of flue gas. Technology exists for enriching the carbon dioxide concentration above the typical 13% level. The Japanese have been developing large-scale flue gas recovery technology since 1990 as recently reported in the Society of Petroleum Engineers Literature (Iijima, 1998). The process is based upon a monoethanolamine (MEA) process with improved solvents and can be used with boilers and gas turbines. The boiler plant is a large-scale operation as $3.4(10^6)$ m^3/D (120 MMcfd) of carbon dioxide are recovered at a purity of 99.9%. The turbine exhaust extraction is a smaller scale process generating 1.4 (10^6) m^3/D (51 MMcfd) of 99.9% purity carbon dioxide. The CO_2 is delivered at 13,800 kPa(g) (2,000 psig) and would be transported via pipeline to the disposal site.

The cost for carbon dioxide extraction from the boiler, including hardware depreciation and operating costs, was estimated to be U.S. \$0.716 per Mcf (\$0.025/m^3). The cost for carbon dioxide from the turbine exhaust was greater, U.S. \$1.20 per Mcf (\$0.042/m^3). The difference in cost may have been partially due to the amount of carbon dioxide in the input stream. For the boiler case, the carbon concentration was 8.55% by volume. The turbine exhaust contained 3.5% carbon dioxide by volume. These costs include compression to but do not include pipeline transportation costs.

An alternate technology, under development by Canada Center for Minerals and Energy Technologies (CANMET), is to pre-treat the flue gas stream to enrich the CO_2 content of the injection stream (Croiset and Thambimuthu, 1999). The output of the process is a flue gas stream that can contain 20 to 75% CO_2, the composition of which can be altered rapidly. There is synergy between the CO_2-ECBM process and the CANMET technology.

Figure 7.11 illustrates the CANMET process that uses oxygen and flue gas recirculation. Oxygen is stripped from air using either a cryogenic or membrane process and feed into a steam boiler that is fueled either with coal, natural gas, or oil. The exhaust stream is recirculated into the boiler while water is rejected. The volume of the recycled stream is altered until the desired concentration of CO_2 in the product stream is attained. The advantages of this process are as follows.

1. The volume of nitrogen in the injection stream is reduced, reducing the amount of inert gas that must be compressed.

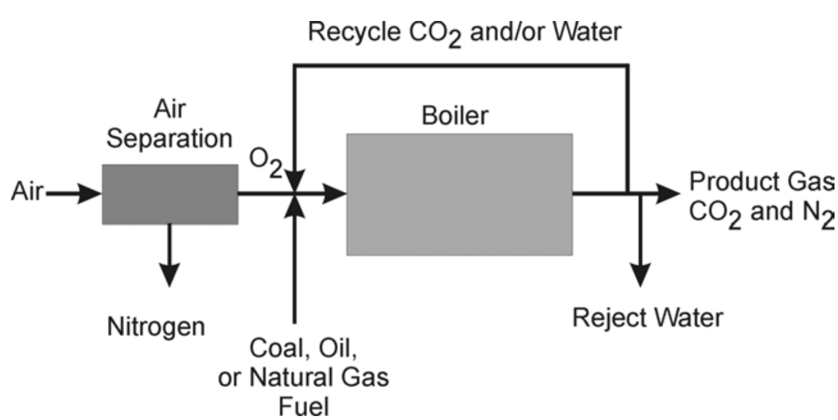
2. Reduction of the nitrogen volume results in a reduction of the CO_2 created - sequestered ratio, maximizing CO_2 storage efficiency.

3. The product gas stream is less corrosive than untreated flue gas, which greatly reduces corrosion problems and associated costs.

4. The process can tolerate a wide range of inert gas concentrations in the fuel stream allowing the use of produced methane that contains significant volumes of nitrogen as the fuel source.

5. The CO_2 - N_2 composition of the injection stream can be altered to maximize the efficiency of the in-situ sequestration - enhanced recovery process.

Figure 7.11 Schematic of CANMET Enriched Oxygen Combustion Process



7.4.2 Delivery to Sequestration Site

A combination of CO_2 and N_2 injection is believed to have the greatest chance for improving the economics of sequestration/enhanced recovery. Therefore, both gases must be available at the sequestration site. The transportation strategy used to design the 9-pattern test was based upon three assumptions.

1. The optimum mix of N_2 and CO_2 is unknown at the present time but the use of N_2 should be minimized to reduce N_2 breakthrough at production wells.

2. CO_2 enrichment technology is large-scale and the equipment must be installed at power plants.

3. The mix of N_2 and CO_2 may need to be varied on a well-by-well basis to control N_2 breakthrough.

Compression and transportation of raw flue gas is not likely to be commercially viable due to the need to compress much more N_2 than will be required at the sequestration site.

The most likely scenario is CO_2 enrichment of flue gas at the power plant with additional N_2 added at the sequestration site. This option minimizes energy use (and thus CO_2 generation) by minimizing the volume of N_2 that is compressed.

There are several methods of generating N_2 on location including:

1. capture and compression of compressor exhaust,

2. flue gas drilling equipment,

3. N_2 extraction from the atmosphere using membrane technology,

4. compression and injection of air, or

5. recycling of N_2 extracted from the production stream with cryogenic technology.

Depending upon the distance between the sequestration site and the CO_2 source, additional compression of the CO_2 at the sequestration site may be required for injection. In this case, the compressor exhaust would be captured and injected using a modified version of the flue gas drilling equipment. Compression of produced gas will be required also. This exhaust must be captured as well.

If further compression of CO_2 is not required, and if insufficient nitrogen is available from the produced gas compressors, the flue gas drilling equipment can be used as a combined N_2/CO_2 source. The advantage of the flue gas drilling equipment is that all exhaust is captured and injected downhole without release to the atmosphere:

Compression is required for extraction of N_2 from air or for air injection. Therefore, there is no advantage of this technology over the flue gas generator.

If the 9-pattern test is installed in a developed gas field, N_2 may not have to be rejected from the produced gas stream. Dilution with gas produced from outside of the 9-pattern project may be sufficient to meet pipeline quality constraints.

However in a full-field operation, nitrogen rejection will be required. The most economical means of nitrogen rejection from the produced well stream will be with a cryogenic process. Cryogenic processes have the advantage of handling larger gas volumes (30 MMcfd) with a low maintenance cost. The input gas stream must be compressed to 3,450 kPa(g) (500 psig) and the hydrocarbon gas stream is output at 2,070 kPa(g) (300 psig). Compression costs are U.S. \$0.194 per Mcf (\$0.0069/m^3) while the plant purchase and maintenance cost is equivalent to U.S. \$0.175 per Mcf (\$0.0062/m^3) for a total processing cost of U.S. \$0.369 per Mcf (\$0.0130/m^3) of well stream. This cost assumes that the plant capacity is fully utilized. If the processed volumes are less, the cost per volume will increase.

Molecular sieve extraction technology is available on a smaller scale. Based upon data supplied by Niject, the cost of N_2 rejection with a 3 MMcfd (85,000 m^3/d) unit is in the range of U.S. \$0.40 per Mcf (\$0.0141/m^3) of produced gas. These units have the disadvantage that the produced gas must be compressed to 970 kPa(g) (140 psig) prior to treating. The output stream is at atmospheric pressure requiring additional compression to pipeline transportation pressures. Only the first compression cost is additional. The second compression would be performed for a carbon dioxide injection project also. The first compression cost is U.S. \$0.18 per Mcf (\$0.0064/m^3) of input stream for a total incremental cost of U.S. \$0.58 per Mcf (\$0.0205/m^3) of well stream to extract the nitrogen. This cost assumes that the plant is fully utilized.

Nitrogen can be rejected by pressure swing adsorption methods also. For a 3 MMcfd well stream, the estimated processing cost for a feed stream containing 30% nitrogen ranges from U.S. \$0.67 (\$0.0237/m^3) to reduce the nitrogen content to 10% nitrogen to U.S. \$0.97 per Mcf (\$0.0343/m^3) to reduce the nitrogen content to 3% (Buras and Mitariten, 1994)

In summary for the 9-pattern test, we plan to transport CO_2 directly from the source and add nitrogen captured from compressor exhaust at the pilot. This plan requires that a central compression / production facility be utilized. There will be a total of 16 injection wells. If each well can accept 14,000 m^3/D (0.5MMcfd), the total injection volume will be 230,000 m^3/D (8 MMcfd).

7.4.3 9-Pattern Design

The sub stages associated with the 9-pattern project are summarized in **Table 7.8** and described below.

Table 7.8 Stage 3, 9-Pattern Testing Sub Stages

Stage	Description
3.1	Permitting
3.2	Injection Well Testing
3.3	Production Well Drilling and Completion
3.4	Injection Well Drilling and Completion
3.5	Flue Gas Source Modifications
3.6	CO_2 Pipeline Construction
3.7	Gathering & Injection System Construction
3.8	Production and Compression Facilities Construction
3.9	Production and Exhaust Injection
3.10	CO_2 Compression Installation
3.11	CO_2 Injection and Hydrocarbon Production

The stage begins by obtaining all the necessary permits for drilling, construction, and pipeline right of ways. Once permits are obtained, construction can begin.

In addition to an areal expansion of the project, the 9-pattern testing effort will involve completion of multiple coal seams. To insure that sufficient permeable coal thickness is present to justify expansion, the permeability of the coal seams should be estimated from water-injection falloff tests. The testing can be performed in one or more of the injection wells used during the 5-spot pilot while awaiting permits. The tests performed in the manner discussed in the section concerning micro-pilot testing prior to stimulation.

The additional coal seams to be added to the project may be located both above and below the seams tested during the 5-spot pilot. The injection-falloff tests can be performed in seams located below the completed seams but there is additional risk of sticking tools in the well. If debris falls on top of the packer during the injection testing, it may be difficult to remove the packer from the well. Therefore, the modified procedure is as follows assuming that the seams to be tested are located below the perforated interval.

1. Rig up a completion rig and remove the injection packer, tubing and permanently installed pressure transducer from the wells.

2. Clean out the well to the plugged back total depth with a bit and casing scraper.

3. Circulate the wellbore volume several times to insure that the return fluid is free of debris.

4. Rig up wireline equipment and perforate the interval of interest with casing guns.

5. Trip in the well with a plastic, drillable bridge plug and set the plug above the interval of interest. The bridge plug should be designed so that a stinger on tubing can be stung into the plug so that injection through the plug is possible. The plug also must hole pressure from above and below. One such plug referred to as an "EZ Drill Bridge Plug" is available from Halliburton.

6. Pick up a bottom-hole injection assembly that consists of the following items from the bottom up.

   a. packer stinger
   b. 6-m (20-ft) pup joint
   c. bottom no-go nipple
   d. 3-m (10-ft) pup joint
   e. upper no-go nipple

7. Rig up slick line equipment and trip in the hole with a self-contained memory electronic pressure / temperature and set the transducer in the bottom no-go nipple. The transducer should be capable of measuring 0.14 kPa (0.02 psi) pressure changes and storing data points every 15 seconds.

8. Rig up surface pumping equipment and injection rate and surface pressure recording equipment.

9. Inject the filtered water at a rate not to exceed 20 liters/minute (5 gal/minute) for a period of eight hours. Total injection volume is 9.6 m^3 (60 barrels).

10. Near the end on the injection period, rig up slick equipment and a plug in a lubricator. Run in the well with the plug and set the plug in the upper no-go nipple. Cease injection after the plug is set and maintain surface pressure of at least 1,500 kPa (220 psig). Trip out of the well with the slick line equipment.

11. Leave the well shut-in for twice the injection period duration or 16 hours.

12. Trip in the well with slick line equipment and recover the plug and transducer.

13. If the pressure data is suitable for analysis, trip out of the well with the injection string. If not rerun the test.

After the test, the plastic packer will remain in the well. A shallower interval between the 5-spot pilot test interval and the deepest interval can be tested in the same manner. To conduct a test above the 5-spot interval, a drillable bridge plug will be set above the 5-spot perforations. The shallower tests can be performed in the same manner as discussed in the micro-pilot section. Drillable bridge plugs will be used to isolate deeper intervals after each test.

At the conclusion of the tests, the bridge plugs can remain in the well and the well used as an observation point for the shallowest interval. It would also be possible to drill out all of the plugs and monitor the wellbore pressure with all seams open. However, this pressure data will be of little value due to the number of seams. If desired, two of the other three injection wells could be recompleted to monitor pressure in other intervals so that up to four intervals could contain a monitor well.

An additional eight injection production patterns must be installed around the original 5-spot pilot as illustrated in **Figure 7.2.** This figure assumed that 0.647 km^2 (160-acre) patterns would be used. The actual size would be selected based upon the evaluation performed during Stage 2. The original production well will remain on production. Twenty-four additional production wells will be drilled, completed, and placed on production as quickly as possible.

Sixteen injection wells will be drilled and completed so that they are ready for injection when the pipeline construction is completed when and site facilities are in place. Forty-one wells are included in the project.

The CO_2 enrichment technology will have to be installed at the power plant at roughly the same time as the wells are drilled. Pipeline construction to the site can be performed simultaneously with the plant modifications.

The production and compression facilities for the original 5-spot pilot are increased to handle the greater volumes. As compression will be required for produced gas treating and transmission, exhaust sequestration will begin simultaneously with production. If additional compression is required for CO_2 injection, it will be installed near the time of the pipeline completion.

A low-pressure gas and water gathering system will be put in place. Buried PVC gas and water lines will be used. Water will be pumped to the central facility with the downhole pump used for artificial lift. Gas and water production and composition will be monitored for each individual well at the central facilities.

Water will leave the metering station and must be disposed. Water disposal requirements can range from surface discharge to underground injection depending upon the water quality. For the purposes of this design, underground injection is the most likely disposal option.

Gas production will leave the metering station and enter a scrubber to remove excessive water. After leaving the scrubber, the gas will be treated to remove remaining water using a glycol dehydration system. These systems usually require compression to between 4,140 to 6,210 kPa(g) (600 to 900 psig) for maximum efficiency. The actual pressure is usually the sales line pressure. If nitrogen rejection is not required, the gas enters the sales line without additional compression.

If nitrogen rejection will be required, the dehydrator will be operated at 3,450 kPa(g) (500 psig). Following dehydration, the gas will enter a cryogenic nitrogen rejection unit. Upon exiting the unit at 2,410 kPa(g) (350 psig), additional compression may be required depending upon the gas sales line pressure.

All compressors must have exhaust collection systems installed. These systems will be very similar to that used by the flue gas drilling equipment. The exhaust will be treated and compressed to injection pressure. After compression, the exhaust will enter a manifold system to be directed in the desired volume to each of the injection wells. The total volume of exhaust entering the manifold is metered. Individual meters are installed on each high-pressure injection line at the central facility. The steel high-pressure injection lines are buried for maximum safety.

7.4.4 9-Pattern Timing

An ambitious estimate of the timing to install the project is summarized in **Figure 7.12**. Permitting could take six months. The actual installation time is between ten and twelve months. Depending upon the infrastructure present, this time could be doubled. **Figure 7.12** illustrates the minimum time case. The injection tests require roughly 4 days per test. Each of the twenty-four new production wells can be drilled in one week and completed in a second week. Twenty-four weeks are required to drill the wells. A completion rig can work simultaneously with the drilling rig after the first well to have all wells completed by the end of week twenty-five. Drilling and completion of the injection wells will require an additional seventeen weeks.

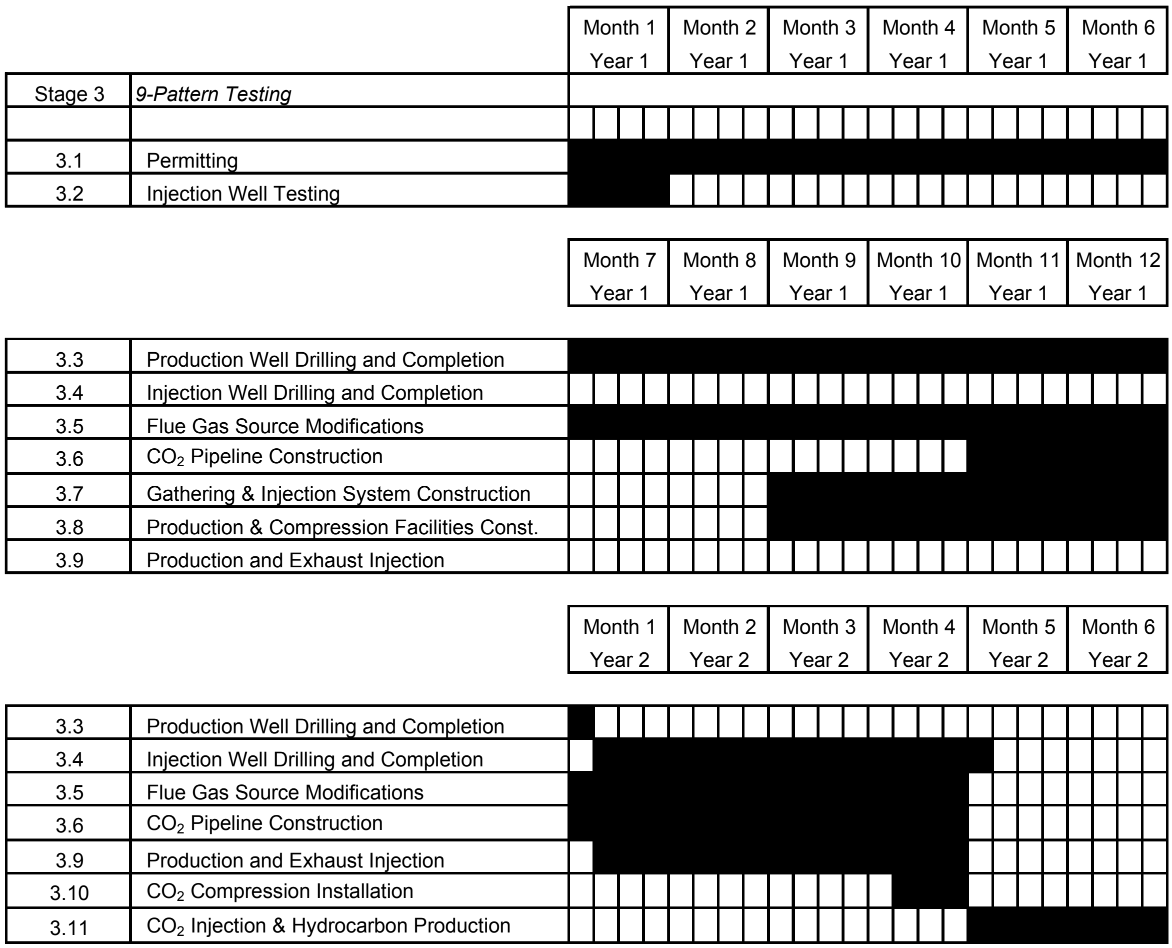
Information is not available concerning the timing of the power plant modifications. Ten months for this effort were assumed. Pipeline construction time depends upon the length of the line. Six months for this effort were assumed.

Gathering and injection system lines can be installed in three months. The production and injection facilities can be installed at the same time and be ready to begin hydrocarbon production at the time the final production well is completed. Exhaust compression and hydrocarbon production will begin simultaneously.

The CO_2 compression installation should be finished when the CO_2 pipeline is completed. Injection of CO_2 can begin at this time.

The duration of injection would depend upon the response and economic return resulting from the project. A range from two to five years is likely required to evaluate the expanded pilot.

Figure 7.12 Stage 3, 9-Pattern Testing Time Requirements



7.4.5 9-Pattern Testing Summary

In summary, a total of 40 additional wells must be drilled and completed to install the 9-pattern test. A power plant must be modified to install a CO_2 collection and compression system. A pipeline from the power plant to the sequestration site must be constructed. Production and compression facilities must be installed. Low-pressure gas and water gathering systems are required as well as high-pressure injection lines. All compressor exhaust must be collected and injected for the N_2 source and to eliminate release of additional pollutants into the atmosphere.

This preliminary plan would likely require modification after the 5-spot pilot data allows proper design of the expanded project.

7.5 References

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CHAPTER 8: ECONOMIC ANALYSIS OF ENHANCED COALBED METHANE PROJECT IN AUSTRALIA

8.1 Introduction

The Dawson River field in south Bowen Basin, Australia was ranked the highest among the eleven potential sites, followed by the south Qinshui Basin, China for locating the CO_2-enhanced coalbed methane (ECBM) pilot plant (Chapter 6). A technical design of the pilot suitable for the Australia and China sites was then carried out in Chapter 7. To ensure that the process can be implemented successfully from both a technical and economic viewpoint, we propose a three-stage process progressing from a micro-pilot (1 well technical demonstration) through a 5-spot pilot (technical demonstration) to an expanded 9 patterns of 5-spot (commercial demonstration). After these three stages, sufficient information would be available to expand the project to a field-wide scale. Each of these stages represents an important milestone in the commercialization process.

In this Chapter, we will develop cost estimates for the three stages of the pilot testing, based on our pilot experience in Alberta, Canada and our knowledge regarding Australian costs. After that, we will prepare a hypothetical economic analysis of an ECBM project (CO_2 or flue gas sequestration) in the south Bowen Basin. The important parameters that will impact on the economic success of the process, both in terms of enhanced coalbed methane recovery and CO_2 sequestration will be discussed.

8.2 Piloting Costs

Micro-Pilot Testing

The micro-pilot involves costs related to field review, well drilling and evaluation, micro-pilot testing, data analysis and 5-spot pilot design. In the micro-pilot test, approximately 200 tonnes of CO_2 are injected over a week into one well. The CO_2 will be trucked to the project site for injection. The estimated cost for the micro-pilot is about $US 669,000 as shown in **Table 8.1** (Details of the costing basis for the micro-pilot are contained in Appendix II-A). The stages follow the description in Chapter 7. The accuracy of the cost estimate is expected to be within the +/- 30% range.

Table 8.1: Cost Estimate for Micro-Pilot Testing at the Dawson River field, Bowen Basin

Stage 1.1 Field Review

	$A ‘000	**$US ‘000**
Field Review	50.0	30.0

Stage 1.2 Formation Evaluation Well Drilling and Evaluation

	$ A '000	**$ US '000**
Production Well Drilling & Completion Costs		
Drilling Contact Costs	135.4	81.3
Road & Site Preparation	16.2	9.7
Rig Transport & Misc. Transport	17.0	10.2
Drilling Fluids	13.0	7.8
Logging (Open Hole)	13.3	8.0
Drill Stem Testing, Coring Analysis	7.5	4.5
Cement & Cementing Services	15.0	9.0
Casing & Attachments	28.9	17.3
Other Equipment & Services	1.8	1.1
Land, Engineering, Supervision & Admin.	18.2	10.9
Drilling Subtotal	266.2	159.7
Service Rig	3.4	2.0
Survey	15.0	9.0
Trucking & Misc. Transportation	0	0
Logging (Cased Hole) & Perforating	37.5	22.5
Tubing & Attachments	10.0	6.0
Pumping Equipment	30.0	18.0
Wellhead	8.4	5.0
Other Equipment & Services	0	0
Engineering, Supervision & Admin.	8.4	5.0
Completion Subtotal	112.7	67.6
Completed Producer Total	378.9	227.3
Contingencies @ 15%	56.8	34.1
Total	435.7	261.4
Formation Evaluation		
On-site & Long-term Desorption Test	45.0	27.0
Wireline Services	32.0	19.2
Coring Costs	20.0	12.0
Contingencies @ 15%	14.6	8.7
Total	111.6	66.9
GRAND TOTAL STAGE 1.2	547.3	328.4

Stage 1.3 Micro-Pilot Testing

	$ A `000	**$ US `000**
Stimulation & Treatment	117.5	70.5
Initial Production Test		
Gas Chromatography and Analysis	4.0	24.0
Production Test Crew & Equipment	32.0	19.2
Supervision	12.0	7.2
Subtotal	48.0	29.0
Gas Injection		
Carbon Dioxide	50.0	30.0
Trucking and Injection	48.0	28.8
Pump Pulling	3.0	1.8
Supervision	12.0	7.2
Subtotal	113.0	67.8
Post-Injection Production Testing		
Gas Chromatography and Analysis	6.0	3.6
Production Test Crew & Equipment	63.0	37.8
Pump Pulling	3.0	1.8
Supervision	12.0	7.2
Subtotal	84.0	50.4
Contingencies @ 15%	54.4	32.6
GRAND TOTAL STAGE 1.3	416.9	250.1

Stage 1.4 Data Analysis & 5-Spot Pilot Design

	$ A `000	**$ US `000**
Data Analysis & Reporting	35.0	21.0
Reservoir Modelling of Field Results	50.0	30.0
Project Assessment & Economics	15.0	9.0
TOTAL STAGE 1.4	100.0	60.0

Summary Stage 1 Costs

	\$ A \`000	**\$ US \`000**
Stage 1.1 Field Review	50.0	30.0
Stage 1.2 Formation Evaluation Well Drilling and Evaluation	547.3	328.4
Stage 1.3 Micro-Pilot Testing	416.9	250.0
Stage 1.4 Data Analysis & 5-Spot Pilot Design	100.0	60.0
Total	**1,114.2**	**668.5**

5-Spot Pilot Testing

The 5-spot pilot involves drilling four additional wells (one producer and three injection wells), converting the micro-pilot well to an injector, construction of a surface facility, injection of CO_2 and flue gas, production testing, data analysis and project design. In the full field pilot, approximately 15,000 tonnes of CO_2 (or flue gas) are injected over six months. The CO_2 (or flue gas) will be generated by exhaust from a propane-fueled compressor supplemented by trucked CO_2, prior to injection. The total cost for the 5-Spot pilot testing is estimated at about \$ US 6.2 million, as shown in **Table 8.2**.

Table 8.2: Cost Estimate for a 5-Spot Pilot Test at the Dawson River field, Bowen Basin

	\$ A \`000	**\$ US \`000**
Stage 2.1 2^{nd} Well Drilling & Completion	547.3	328.4
Stage 2.2 2^{nd} Well N_2/CO2 Micro-Pilot Testing	416.9	250.1
Stage 2.3 Conversion of first two wells to injection Wells	200.0	120.0
Stage 2.4 Production Well Drilling & Completion	630.7	378.4
Stage 2.5 Pre-Injection Production	48.0	28.8
Stage 2.6 Remaining 2 Injection Wells Drilling & Completion	794.8	476.9
Stage 2.7 Surface Facility Construction	5,974.8	3,584.9
Stage 2.8 Injection & Production	1,132.7	679.6
Stage 2.9 Final Testing	84.0	50.4
Stage 2.10 Analysis & Expansion Design	500.0	300.0
Total	**1,0329.2**	**6,197.5**

Capital and Operating Cost Breakdown	**\$ A \`000**	**\$ US \`000**
Capital (Stages 2.1, 2.3, 2.4, 2.6 and 2.7)	8,147.6	4,888.5
Operating (Stages 2.2, 2.5, 2.8, 2.9 and 2.10)	2,181.6	1,309.0
Total	10,329.2	6,197.5
Less 50% cost recovery of compressor and flue gas/CO_2 generator	2,350.0	1,410.0
Stage 2 Total (net)	**7,979.2**	**4,787.5**

The capital cost for a 5-spot pilot test is estimated to be approximately \$US 4,889,000. The injection/production operation will run continuously for at least 6 months. The entire stage will require roughly two years to complete. Estimated operating cost would be about \$US 1,309,000. Hence, the total gross cost for the 5-spot pilot is about \$US 6,198,000, prior to cost recovery for the sale of the compressor and CO_2/flue gas generator (estimated at 50% of cost or US\$ 1,410,000). Therefore, the total net cost for the 5-spot pilot is estimated to be \$US 4,788,000. Details of the capital and operating cost estimate for the 5-spot pilot are contained in Appendix II-A.

9-Pattern Testing (Commercial Demonstration)

It should be clear from the 5-spot pilot test whether a larger scale effort is warranted. If so, eight additional patterns can be installed surrounding the 5-spot pilot. The decision to expand hinges on the ability to deliver injection fluids (CO_2 or flue gas) to the site without excessive transportation and compression costs. The 9 patterns of 5-spot proposed (45 well) commercial demonstration are injecting 400 tonnes CO_2 per day or 120,000 tonnes CO_2 per year. At the 5-spot field pilot stage, the injection gas is generated on site by using the exhaust gas generated by a gas engine. At the commercial demonstration stage, a slipstream from a coal-fired power plant, the waste stream from a gas plant is utilized, or some other large source may be utilized. It is very difficult to estimate the cost of the commercial demonstration at this time, because we do not have the 5-spot pilot reservoir performance data. The injection rate, injection pressure, source of CO_2, produced well stream production rate, gas composition etc. would greatly impact on the surface facility design and cost. From the operation perspective, the sales of the methane gas can probably offset some of the operating costs. A rough estimate for the commercial demonstration stage (Stage 3) is of the order of \$US 35,000,000 not considering the sale of methane.

8.3 Hypothetical Commercial ECBM project at Dawson River, South Bowen Basin

Initially ECBM projects will likely occur at the conventional CBM project sites, due to the presence of an existing infrastructure, which greatly reduces the investment risk. Therefore, our economic analysis assumes that land permits; micro-pilot; 5-spot pilot and 9 pattern demonstration testing have been completed for the hypothetical ECBM project site.

The Dawson River site is located to the south of the Dawson Valley field in the southeast district of the Bowen Basin. Lease PL 94 occupies an area of 242 km^2 (24,280 ha.). Gas in place is estimated at 58 Gm^3 (2 Tcf). Resource concentration is 2,284 $10^3 m^3/ha$. Our economic analysis assumes an ECBM project, which encompasses 6,475 hectares or approximately 27% of the prospective lease. It is approximately 0.3%, a relatively small portion of the Bowen Basin (IEA GHG, 1998).

A significant cost of an ECBM project will be in the capture, purification, compression and transportation of the CO_2 from the coal-fired generation plant to the project site. The CO_2 supply cost is dependent on the CO_2 concentration in the flue stack, capture/separation process selected, compression requirements and distance to the ECBM project site. Therefore, for easier interpretation, our economic analysis assumes a high quality CO_2 at pipeline pressure (8,275 kPag) would be available at the project site at zero cost. Our analysis compares the economic costs/benefits of ECBM projects versus conventional CBM projects in the Bowen Basin, at various constant plant-gate gas prices. These results were then used to determine an affordable CO_2 cost/credit for ECBM projects so that it can compete with conventional CBM projects.

8.3.1 Reservoir Parameters Assumption

The evaluation of the economic viability of ECBM projects in Australia requires a reservoir model based on the local geology, engineering practice and operations.

Following a review of some of the current projects and geology associated with potential acreage, a reservoir model has been assembled to yield representative values for the Bowen Basin. The reservoir model assumes a project with prospective CBM coals measures at a modest depth of 610 metres. The CBM coals were assumed to be normally pressured and gas saturated.

A range of depth to prospective coal horizons does occur with CBM exploration in the Bowen Basin. An average depth of 610 metres was selected after a review of the available CBM reservoir data for the Dawson River, Fairview and Durham Ranch projects. Prospective coal measures are present at these projects from 425 to 850 metres, with as many as 10 seams present. A total of 59 wells have been drilled and completed in these projects, with initial gas rates ranging from 1.0 to 85.0 10^3m^3 per day per well, an average of 6.5 10^3m^3 per day per well. However, insufficient data was available to prepare a relationship of gas content and permeability variations to depth.

A range of well spacing was considered, from 32 to 129 hectares, for the Bowen Basin reservoir model. It should be noted that, well spacing for any project is a function of productivity, capital requirements, useful life of production facilities and ultimately project economics. A well spacing of 32 hectares would result in significant additional capital costs for the drilling of producers (100% increase) and injectors (50% increase). While 129-hectare well spacing results in significant capital cost reductions for the drilling of producers and injectors, it also provides reduced project productivity and a very long project life (> 40 years). It was determined that 64 hectare well spacing was a reasonable assumption for the Bowen Basin reservoir model.

The CBM reservoir and project parameters used for the conventional and ECBM projects are listed in **Table 8.3**.

Table 8.3: CBM Reservoir and Project Parameters

Development Case	Conventional	ECBM
Average coal seam depth	610 m	610 m
Net coal pay	9 m	9 m
Coal methane content (saturated)	8.9 cc/gm	8.9 cc/gm
Initial reservoir pressure	5,930 kPa	5,930 kPa
Reservoir temperature	32°C	32°C
Abandonment reservoir pressure	1,380 kPa	1,380 kPa
Sp. Gravity	1.4	
Coal absolute permeability	5 md	
Initial well rate	4.2 $10^3m^3/d$	4.2 $10^3m^3/d$
Plateau well rate	14 $10^3m^3/d$	24 $10^3m^3/d$ (CO_2) and 35 $10^3m^3/d$ (flue gas)
Gas-water ratio (initial)	7.5 $m^3/10^3m^3$	7.5 $m^3/10^3m^3$
Derived		
CBM gas in place	1,479 $10^3m^3/ha$	1,479 $10^3m^3/ha$
CBM OGIP per well	95 10^6m^3	95 10^6m^3
Recovery factor	50%	80%
Project CBM reserves	4.8 10^9m^3	7.7 10^9m^3
CO_2 or flue gas sequestered	0	15.3 10^9m^3
Number of producing wells	100	100
Number of CO_2 injection wells	0	81
Producer well spacing	64 ha	64 ha
Acreage	6,475 ha	6,475 ha

8.3.2 Production Forecasts

Conventional Project

The conventional CBM project is projected to require 50 CBM producing wells initially with a further 50 wells drilled in subsequent years. The first-year average production rate will be 210 10^3m^3 per day (4.2 10^3m^3 per day per well), with a maximum rate of 704 10^3m^3 per day (14 10^3m^3 per day per well) in the third year, sustained for a further 10 years through drilling, before declining to the economic limit **(Figure 8.1)**.

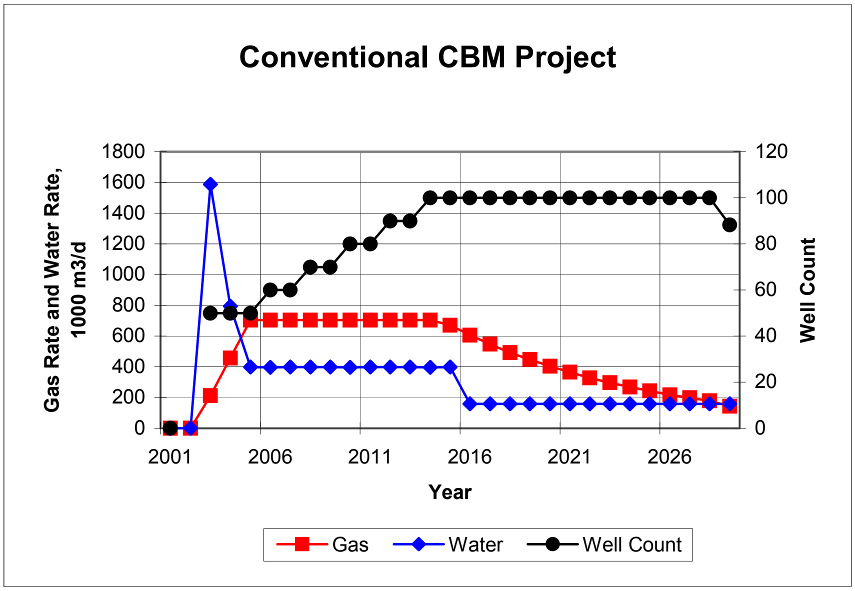
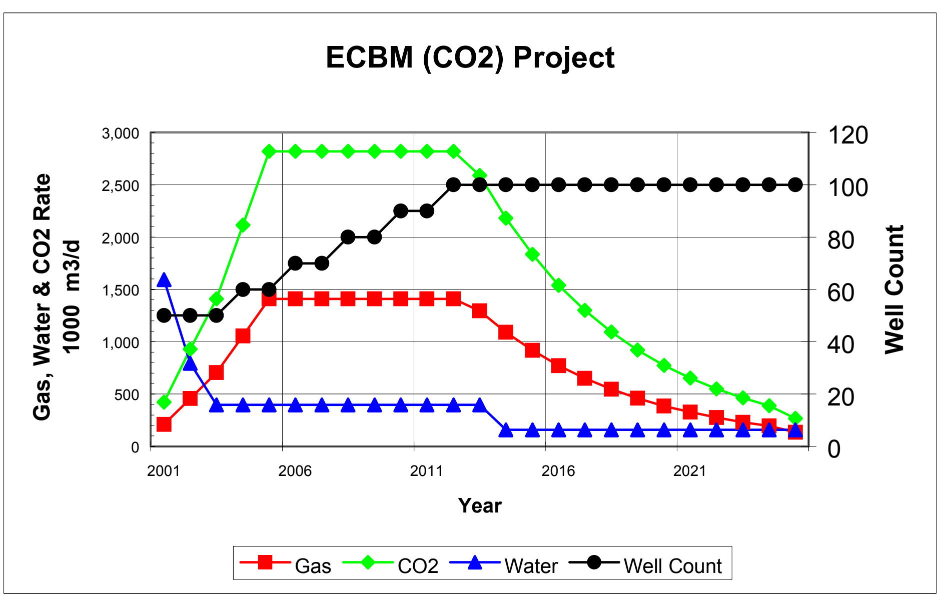


Figure 8.1 Gas and Water Production Rates

ECBM (CO_2) Project

The ECBM (CO_2) project is projected to require 50 CBM producing wells plus 40 CO_2 injection wells initially with a further 50 wells and 41 CO_2 injection wells drilled in subsequent years. The project will achieve a first-year average production rate of 210 10^3m^3 per day (4.2 10^3m^3 per day per well) with a maximum rate of 1,410 10^3m^3 per day (24 10^3m^3 per day per well) in the fifth year, sustained for a further 8 years through drilling before declining to the economic limit **(Figure 8.2).** The increased productivity per well (10 10^3m^3 per day per well) is estimated from a review of the CO_2 displacement process that has been operated by Burlington Resources at the Allison Unit ECBM project, San Juan Basin in northern New Mexico.

Figure 8.2 ECBM (CO_2) Project

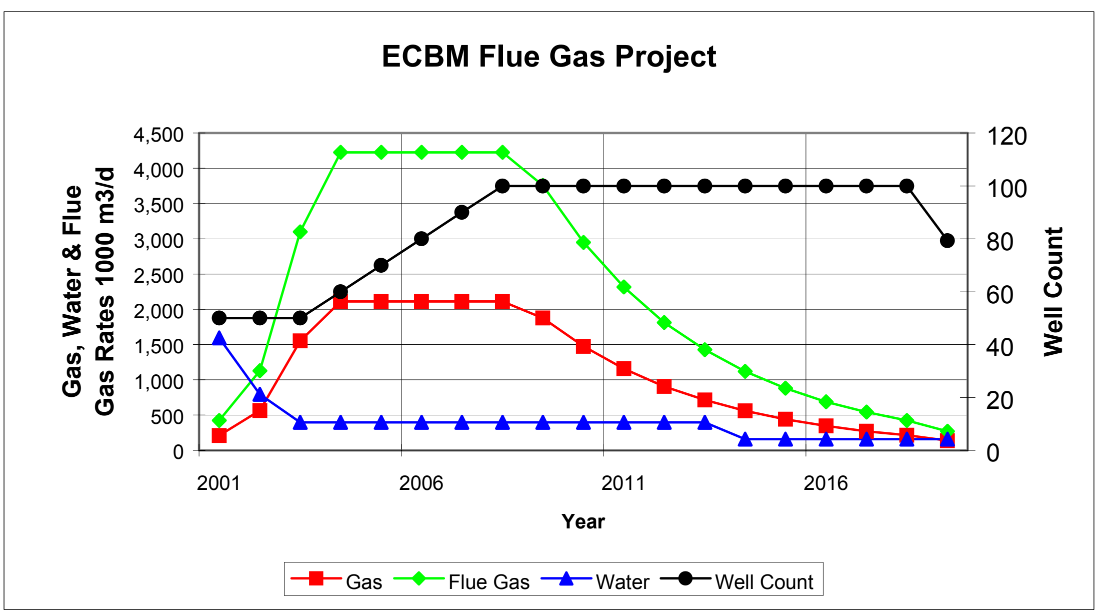


The ECBM project will inject 422 10^3m^3 per day (10.6 10^3m^3 per day per well) of CO_2 initially, with a maximum injection of 2,810 10^3m^3 per day (34.7 10^3m^3 per day per well) in the third year and sustained for 8 years. Subsequently, the CO_2 injection decline is based on a 2:1 ratio of the CBM gas production. For the Burlington Resources project, the ratio is close to 3. This is probably due to reservoir heterogeneities. However, reservoir heterogeneities could affect the ratio in either direction. Again, we are faced with a paucity of data. This is only one project. Presumably, with more projects other ratios will be measured. We feel at this stage the lab-measured isotherm is the best data to base our analysis. Hence, the total volume of CO_2 sequestered will be 15.3 10^9m^3 during the life of the project, assuming a 2:1 displacement ratio of CO_2 to methane for the project. The amount of CO_2 sequestered during the life of the ECBM project is estimated to be 28.6 million tonnes.

ECBM (Flue Gas) Project

The ECBM (flue gas) project is projected to require 50 CBM producing wells plus 40 flue gas injection wells initially with a further 50 wells and 41 flue gas injection wells drilled in subsequent years. The project will achieve a first-year average production rate of 210 10^3m^3 per day (4.2 10^3m^3 per day per well) with a maximum rate of 2,114 10^3m^3 per day (35 10^3m^3 per day per well) in the fifth year, sustained for 5 years through drilling before declining to the economic limit **(Figure 8.3).** The increased productivity per well (21 10^3m^3 per day per well) compared to a conventional well is anticipated due to the flue displacement process (combination of N_2 and CO_2). The ability of N_2 to displace adsorbed methane has been observed at Amoco's ECBM pilot project (N_2 injection) in the San Juan Basin in northern New Mexico. The pilot production increased from a pre-injection rate of 7 10^3m^3 per day up to 34 10^3m^3 per day (500% increase, compared to **Figure 1.1**).

Figure 8.3 ECBM Flue Gas Project



It is likely that the flue gas will need to be composed of a higher percentage of CO_2 than N_2, throughout the life of the ECBM project. The N_2 component is used to accelerate methane displacement in the near cleat area and improve early productivity, while the CO_2 component improves the overall displacement efficiency and ultimate methane recovery. The N_2 concentration will likely be higher in the early phases of injection and decrease with time. An average injection for the life of the ECBM (flue gas) project could be in the order of CO_2 (80%) and N_2 (20%).

The ECBM (flue gas) project will inject 423 10^3m^3 per day (10.6 10^3m^3 per day per well) of flue gas initially, with a maximum injection of 4,225 10^3m^3 per day (52.2 10^3m^3 per day per well) in the third year and sustained for a further 5 years. Subsequently, the flue gas injection decline is also based on a 2:1 ratio of the CBM gas production. The total volume of flue gas sequestered will be 15.3 10^9m^3 during the life of the project, assuming a 2:1 displacement ratio of flue gas to methane for the project. The amount of CO_2 sequestered during the life of the ECBM project is estimated to be 22.9 million tonnes, assuming 80% CO_2 average in the injected volumes. It should be noted that as the nitrogen content in the flue gas increases, the displacement ratio decreases. Typically, for a 100% nitrogen injection, 0.5 to 1 volume of nitrogen is adsorbed for each volume of methane displaced. This would impact positively on the economics. The extent of the variation of this parameter will be verified in the pilot testing with flue gas by varying the CO_2/N_2 composition in the injection gas. For this simple analysis, it is assumed that the 2 to 1 ratio stays the same at 80% CO_2 and 20% N_2.

Breakthrough of N_2 to the producing wells will occur. To minimize this, a high CO_2/N_2 average injection ratio was chosen. It is assumed in this analysis that minimal N_2 breakthrough can be tolerated by blending of various production streams to pipeline specifications, thus avoiding the requirement for expensive N_2 rejection.

8.3.3 Capital Costs

ECBM Project

Our hypothetical ECBM project involves the drilling and completion of 100 producers and 81 injectors, based on a 5-spot development plan. The CO_2 or flue gas will be generated by exhaust from a coal-fired generation plant, prior to injection. Total well costs to drill either a CBM or CO_2 injection well, were estimated based on anticipated costs for a large project. It was assumed that CBM wells and CO_2 injection wells would require a hydraulic fracture-stimulation. The capital costs are set out below in **Table 8.4**.

Table 8.4: Drilling and Completion Costs (Massarotto, 1999)

	Estimated Cost US$ '000/Well
Production wells (610 metres total depth) (drilling and completion; excluding fracture-stimulation)	195
Hydraulic fracturing	105
Total	**$300**

The production facilities and field infrastructure requirements for this project are based on a CBM producing well spacing of 64 ha, which dictates the costs for flowlines, satellite separation, metering stations and gathering lines. The raw gas production will require treating and compression prior to entering the high-pressure transmission line. The removal of CO_2 will be required for both the conventional and ECBM projects, unless the gas is used locally. The removal of N_2 will be required in the flue gas project. However, due to the staged drilling program, the opportunity will exist to blend producing wells with varying N_2 and/or CO_2 levels, to meet or minimize the size of the facilities. A high-pressure transmission line requirement was taken into account for the compression required (745 KW). Capital costs for the project were estimated and are presented in **Table 8.5.**

Table 8.5: Production Facilities and Field Infrastructure Costs (Massarotto, 1999)

	Conventional Well $US '000/Well	**Injection Well $US '000/Well**
Flowlines	60	12
Gas gathering lines	30	30
Gas delivery line	6	6
Satellite stations	24	6
Gas treatment and compression facilities	60	0
Engineering, administration and management @ 10%	18	6
Total	**$198**	**$60**

8.3.4 Operating Costs

Operating costs are categorized as fixed and variable costs, a cost for well workovers has been included in the monthly fixed costs. Gas turbine-drive compressors have been assumed with gas shrinkage of 5 percent deducted from the CBM production available for sale. Costs for water treatment and disposal have been included, though a common practice in the Bowen Basin is for individual well evaporation ponds. Our analysis assumes similar monthly well operating costs for either the conventional or ECBM well. No additional costs were added for gas treating for the ECBM project. The details of the operating cost assumptions are contained in **Table 8.6.**

Table 8.6: Operating Costs

	Conventional and ECBM Cases Estimated Cost
Production—fixed costs - Operations (producer or injector) - Administration, engineering and management	$US 900/Well-Month
Production—variable costs - Compression - Gas Treating - Water disposal	 $US 3.55/10^{3}m^3 $US 1.77/10^{3}m^3 $US 0.94/ m^3

8.3.5 Financial and Fiscal Terms

Gas prices were interpreted to vary with terms and conditions, however project economics were prepared for constant plant gate prices ranging from $US 0.50 to $US 3.00/GJ. The heating value of dry natural gas is taken as 37.23 GJ per 10^3m^3.

Royalty in Queensland is 10% of the wellhead net revenue (gross revenue less operating costs). The corporate income tax rate is 36%, after allowing for straight-line depreciation over 15 years for all development expenditures. The financial and fiscal terms are set out in **Table 8.7.**

Table 8.7: Financial and Fiscal Terms

Plant gate gas price (constant)	$US 0.50 to $US 3.00/GJ
Royalty (on wellhead "net" revenue)	10%
Depreciation life (on development costs)	15 years
Income tax rate	36%

8.4 Economics Analysis

The economic results for the conventional CBM and ECBM projects are based on the project development plan, capital and operating costs and fiscal terms set out above.

Conventional CBM Project

The economic analysis of the conventional CBM project indicates that the minimum constant plant-gate gas price required to achieve a 10% rate-of-return, after income taxes, is approximately $US 1.10 per GJ. The project payout period is 7.5 years with a rate-of-return of 14.4%, on a before tax basis. Appendix II-B presents the economic results for constant plant-gate gas prices ranging from $U.S. 0.50 to $U.S. 3.00 per GJ.

ECBM (CO_2) Project

The economic analysis of the ECBM (CO_2) project indicates that the minimum constant plant-gate gas price required to achieve a 10% rate-of-return, after income taxes, is approximately $US 1.00 per GJ, assuming no cost for CO_2 (high quality and compressed) at the project site. The project payout period is estimated to be 7.5 years with a rate-of-return of 15%, on a before tax basis. A cashflow projection of the ECBM (CO_2) Project for the $US 1.39 per GJ plant-gate gas price case is shown in **Table 8.8**. Appendix II-C presents the economic results for constant plant-gate gas prices ranging from $US 0.50 to $US 3.00 per GJ.

Table 8.8 Projected 20 Year Cash Flows for a CO_2 ECBM Project under a $US 1.39/GJ Gas Price

Summary Report
Case: Bowen Basin - ECBM (CO2) - US$1.39/GJ
(Nominal values)

Net Present Values

Disc Rate (%)	Before Tax Oper Inc. MM$	Before Tax Cap. Inv. MM$	Before Tax Cash Flow MM$	After Tax Cash Flow MM$
0	254	76	179	105
6	152	63	89	48
8	129	60	69	34
10	110	57	52	23
12	94	55	39	14
14	82	53	29	7
Arr:	254	76	179	105

Case Description

Bowen Basin, Australia
Enhanced Coalbed Methane Case
CO2 Sequestration Project
100 Producing Well Development
81 CO2 Injection Wells

Global:	Default
Model:	Australia CBM
Currency:	U.S. Dollar
Discount Date:	2000/01
Evaluation Date:	2000/01

Economic Indicators

		B.Tax	A.Tax
ROR	%	22.7	16.3
Payout Period	Stnd. (mo's)	72.2	90.3
	Proj. (mo's)	86.5	103.6
Undisc. PIR	$/ $	2.36	1.39
8.0 Pcnt. PIR	$/ $	1.15	0.57
12.0 Pcnt. PIR	$/ $	0.71	0.25
NPV/Vol @ 8.0	$/E9m3	8.96	4.44
NPV/Vol @ 12.0	$/E9m3	5.12	1.83
Economic Limit Date		2049/07	

Products Recovery

		Gross	WI
Oil	E6m3	0	0
Gas-Raw	E9m3	8	8
Gas-Sales	E9m3	7	7
Ethane	E6m3	0	0
Propane	E6m3	0	0
Butane	E6m3	0	0
Cond.	E6m3	0	0
Sulphur	E6t	0	0
Other	E9m3	15	15

Company WI

	Initial %	Final %
Working	100	100
Oil	100	100
Gas	100	100
Byprod.	100	100
Other	100	100
Capital	100	100
Royalty	100	100

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Date	Number of Wells	Gas Raw Volume E9m3	Gas Sales Volume E9m3	Water Volume E6m3	Flue Gas Volume E9m3	Gas Price $/GJ	Revenue MM$	Operating Costs MM$	Gas Royalty MM$	Operating Income MM$	Capital MM$	Before Tax Cash Flow MM$	Income Taxes MM$	After Tax Cash Flow MM$
2000(12)	0	0	0	0	0	1.39	0	0	0	0	36	-36	0	-36
2001(12)	50	0	0	0.6	0	1.39	4	1	0	2	0	2	0	2
2002(12)	50	0	0	0.3	0	1.39	8	2	1	6	0	6	1	5
2003(12)	50	0	0	0.1	1	1.39	13	2	1	10	8	2	2	-1
2004(12)	60	0	0	0.1	1	1.39	19	3	2	15	0	15	4	10
2005(12)	60	1	0	0.1	1	1.39	25	4	2	20	8	12	6	6
2006(12)	70	1	0	0.1	1	1.39	25	4	2	20	0	20	6	14
2007(12)	70	1	0	0.1	1	1.39	25	4	2	20	8	12	6	6
2008(12)	80	1	0	0.1	1	1.39	25	4	2	20	0	20	6	14
2009(12)	80	1	0	0.1	1	1.39	25	4	2	19	8	12	5	6
2010(12)	90	1	0	0.1	1	1.39	25	4	2	19	0	19	5	14
2011(12)	90	1	0	0.1	1	1.39	25	4	2	19	8	11	5	6
2012(12)	100	1	0	0.1	1	1.39	25	4	2	19	0	19	5	14
2013(12)	100	0	0	0.1	1	1.39	23	4	2	18	0	18	5	13
2014(12)	100	0	0	0.1	1	1.39	20	3	2	15	0	15	3	11
2015(12)	100	0	0	0.1	1	1.39	17	3	1	12	0	12	3	10
2016(12)	100	0	0	0.1	1	1.39	14	3	1	10	0	10	3	8
2017(12)	100	0	0	0.1	0	1.39	12	2	1	8	0	8	2	6
2018(12)	100	0	0	0.1	0	1.39	10	2	1	7	0	7	2	5
2019(12)	100	0	0	0.1	0	1.39	8	2	1	6	0	6	1	4
Sub.		7	7	2.8	14		350	57	29	264	76	188	70	118
Rem.		1	1	0.3	1		28	35	2	-9	0	-9	4	-13
Total		8	7	3.2	15		378	92	31	254	76	179	73	105

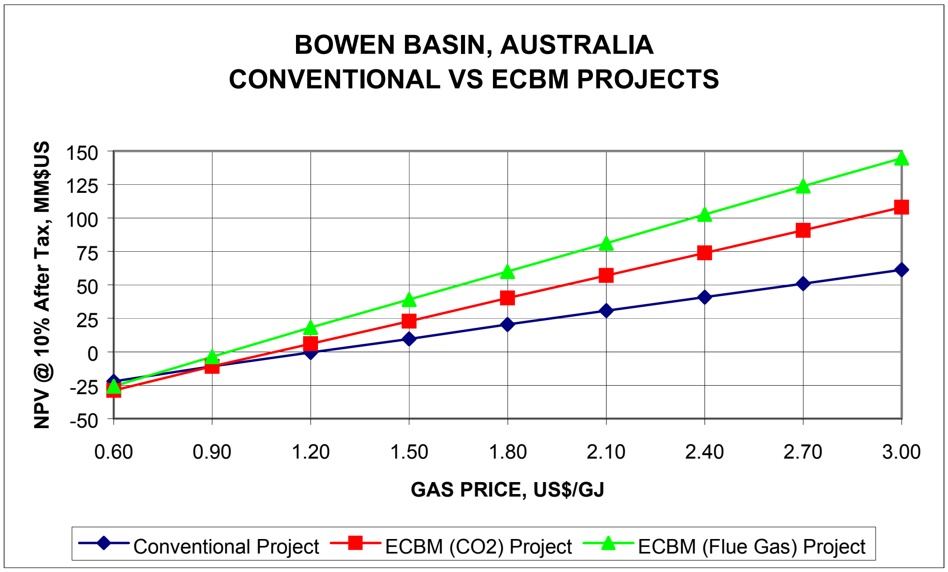
Peep

ECBM (Flue Gas) Project

The economic analysis of the ECBM (flue gas) project indicates that the minimum constant plant-gate gas price required to achieve a 10% rate-of-return is approximately $US 0.90 per GJ, assuming no cost for flue gas (injection quality and compressed) at the project site. The project payout period is estimated to be 7 years with a rate-of-return of 16%, on a before tax basis. Appendix II-D presents the economic results for constant plant-gate gas prices ranging from $US 0.50 to $US 3.00 per GJ.

Figure 8.4 presents the economic results for both the conventional and ECBM projects for net present values at 10% after taxes versus constant plant-gate gas prices.

Figure 8.4 Conventional Vs ECBM Projects



CO_2 and Flue Gas Costs at the Project Site

An analysis was completed to determine the affordable price of CO_2 and flue gas sources at the plant-gate for various constant gas prices. Thus determining the maximum cost of CO_2 and flue gas, which could be charged for capture/separation, compressing and transporting the CO_2 to the project site and still allow the operator to achieve a similar net present value, after taxes, as compared to a conventional CBM project. In other words, the affordable price of CO_2 is the maximum price that the CO_2 – ECBM project can pay for the CO_2 while attaining the same net present value as the conventional CBM project.

Figures 8.5 and 8.6 present the allowable CO_2 and flue gas cost in $US per tonne versus constant plant-gate gas prices. For example, the affordable prices for the CO_2 and flue gas at plant-gate gas price of $US 1.50/GJ are $US 2.35 and $US 3.80/tonne, respectively. This price is not sufficient to cover the full cost of capture/separation and compression of the CO_2 and delivery to site. This cost is estimated at about $US 25 – 35/tonne for recovering CO_2 from coal-fired power plant flue gas using an amine separation process. A substantial credit would be needed for disposing of waste CO_2 in order to make this attractive.

Figure 8.5 CO_2 and Flue Gas Cost – Plant Source to ECBM Project (US $/tonne)

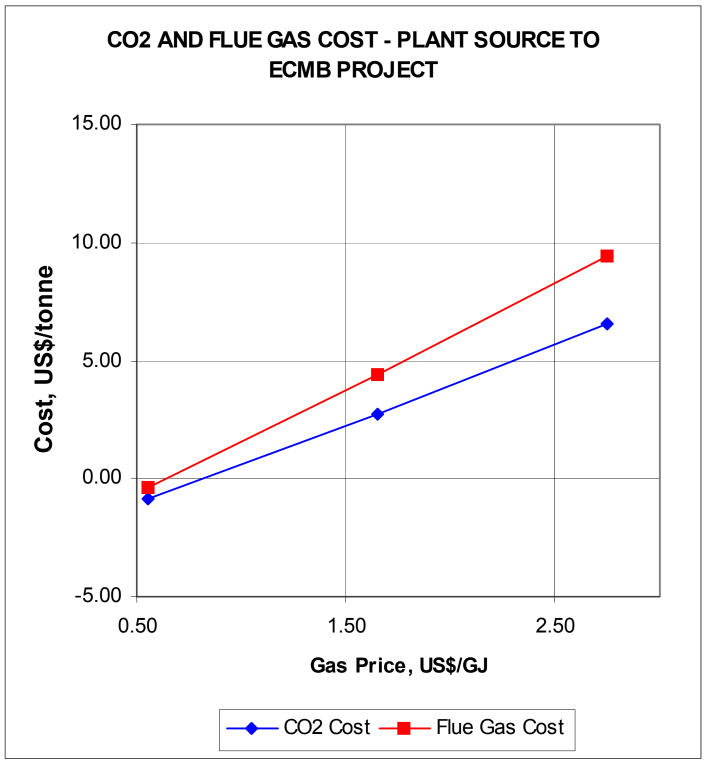
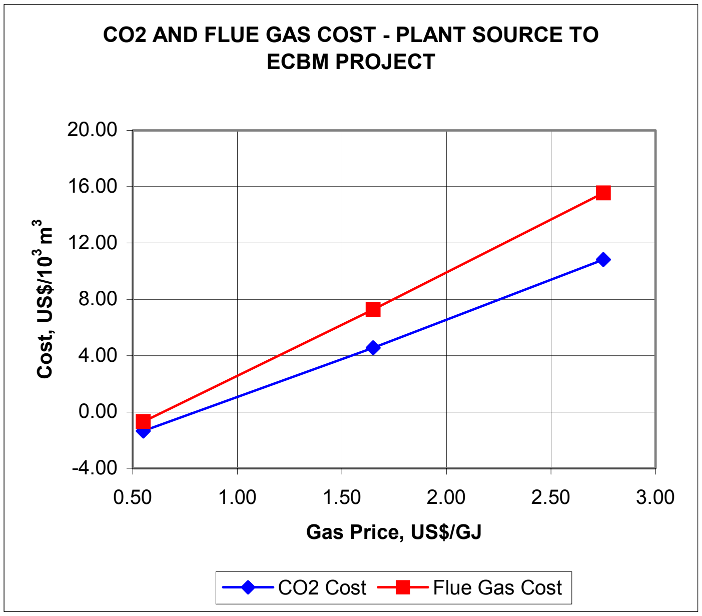


Figure 8.6 CO_2 and Flue Gas Cost – Plant Source to ECBM Project (US\$/10^3m^3)



8.5 Net CO_2 Sequestered

One possibility of an additional revenue stream for the CO_2-ECBM process is through the creation of CO_2 credits. CO_2 not released to the atmosphere should be allowed to earn credits towards the country's CO_2 reduction target under the Kyoto Protocol. This would create a value for the CO_2 sequestered in the coalbeds. Currently, there is no Government policy in place to do this. However, many countries including the U.S., Canada and Australia are considering this option.

For the credit system to work, we must introduce the concept of CO_2 avoided or net CO_2 sequestered. In the sequestration case, energy used for capture and compression generates additional CO_2 emissions, which is precisely what we want to avoid. The process of recovering the ECBM injection volumes (CO_2 or flue gas) from coal-fired generation or other industrial sources requires a source of energy that also results in CO_2 emissions. The process of compressing the ECBM injection volumes for transmission to the project site will also create CO_2 emissions. These CO_2 emissions generated in the process of providing an ECBM injection volume to the project site must be deducted from the CO_2 volumes sequestered to calculate the net CO_2 sequestered.

To calculate the CO_2 avoided or net CO_2 sequestered requires some engineering details, as it is process dependent and fuel dependent. Just as an illustration, using the example from Wong et al., (2000) which calculates that net sequestered CO_2 volume is approximately 65 percent of the injected CO_2 volumes, our hypothetical development in the Bowen Basin has provided a net CO_2 sequestering of approximately 18.6 million tonnes for the ECBM (CO_2) project and 14.9 million tonnes for the ECBM (flue gas) project.

8.6 Conclusions

- The potential for CO_2 sequestration in the Bowen Basin is significant but will require a CO_2 emission credit to achieve comparable economic results to conventional CBM developments.

- The cost to capture, purify, compress and transport CO_2 to an ECBM project site can be significant. However, a small number of ECBM developments may still be possible near coal-fired generation plants, if plant-gate gas prices increase significantly or the cost of CO_2 at the project site is reduced.

- Initially ECBM projects will likely occur in conjunction with existing conventional CBM projects, due to the presence of an established infrastructure, which greatly reduces investment risk.

- The economic analysis assumes a 2:1 ratio of CO_2 injected to CH_4 produced. This ratio is based on lab-measured isotherm, rather than actual field test. As this ratio would impact greatly on the economics, the economic analysis should be re-visited when the new data are available from field measurements.

- Our hypothetical ECBM (CO_2) project resulted in approximately 15.3 10^9m^3 of CO_2 (28.6 million tonnes) being sequestered in an area of 6,475 hectares or 27% of the prospective Dawson River site, resulting in a net CO_2 sequestering of approximately 18.6 million tonnes for this ECBM (CO_2) project.

- Our hypothetical ECBM (flue gas) project resulted in approximately 15.3 10^9m^3 of flue gas (22.9 million tonnes of CO_2) being sequestered, resulting in a net CO_2 sequestering of approximately 14.9 million tonnes.

- Capital costs for drilling and infrastructure in the Bowen Basin could be reduced with additional service competition or larger scale projects. A reduction in capital costs would increase the allowable CO_2 costs landed at the project site.

- The use of flue gas or varying combinations of CO_2 and N_2 in an ECBM project would likely result in a faster release of methane to the producing wells and thereby improve the economics results at lower gas prices. Additional research into the optimum percentages, at various stages of the project life, is required to better understand the potential for this process.

- Additional conventional CBM development in the Bowen Basin will result in a better understanding of the reserve potential and reservoir performance data. This additional data plus results from ECBM projects in the US and Canada will provide a better understanding of the CO_2 and flue gas sequestration potential for the Bowen Basin.

8.7 References

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Wong, S., Gunter, W.D. and Mavor, M.J., 2000. Economics of CO_2 Sequestration in Coalbed Methane Reservoirs, Proceedings of 2000 SPE/CERI Gas Technology Symposium, April 3-5, Calgary, Alberta. SPE Paper 59785, 8 p.

CHAPTER 9: ECONOMIC ANALYSIS OF ENHANCED COALBED METHANE PROJECT IN CHINA

9.1 Introduction

The Jincheng field in south Qinshui Basin, China was ranked the second highest among the eleven potential sites for locating the CO_2-enhanced coalbed methane (ECBM) pilot plant (Chapter 6). A technical design for the pilot was carried out in Chapter 7. In Chapter 8, we have developed cost estimates for the three stages of the pilot testing for the Australian site. The cost estimates are:

- Stage 1: micro-pilot (1 well technical demonstration) $ US 669,000;
- Stage 2: 5-spot pilot (technical demonstration) $ US 6.2 million; and
- Stage 3: 9 patterns of 5-spot (commercial demonstration) $ US 35 million.

We then carried out a hypothetical economic analysis of an ECBM project (CO_2 or flue gas sequestration) in the south Bowen Basin, Australia.

In this Chapter, we will develop cost estimates for the same three stages of the pilot testing, based on our pilot experience in Alberta, Canada and our knowledge regarding China costs. After that, we will prepare a hypothetical economic analysis of an ECBM project (CO_2 or flue gas sequestration) in the south Qinshui Basin. The differences between the two sites cost estimates and economics will also be discussed. A Chinese assessment of the south Qinshui Basin site is included in Appendix III.

9.2 Piloting Costs

Micro-Pilot Testing

Table 9.1 shows the cost estimate for the micro-pilot testing at the Jincheng field, south Qinshui Basin. Total cost for the Stage 1 Micro-Pilot Testing is estimated at $ US 732,000. Details of the costing basis are contained in Appendix IV-A. The accuracy of the cost estimate is expected to be in the +/- 30% range. In the micro-pilot test, approximately 200 tonnes of CO_2 are injected over a week into one well. The CO_2 will be trucked to the project site for injection.

Table 9.1: Cost Estimate for Micro-Pilot Testing at the Jincheng Field, South Qinshui Basin

Stage 1.1 Field Review

	$US '000
Field Review	30.0

Stage 1.2 Formation Evaluation Well Drilling and Evaluation

	$ US '000
<u>**Production Well Drilling & Completion Costs**</u>	
Drilling Contact Costs	80.0
Road & Site Preparation	8.2
Rig Transport & Misc. Transport	18.5
Drilling Fluids	8.0
Logging (Open Hole)	15.0
Drill Stem Testing, Coring Analysis	8.5
Cement & Cementing Services	12.5
Casing & Attachments	30.8
Other Equipment & Services	2.2
Land, Engineering, Supervision & Admin.	22.5
Drilling Subtotal	206.2
Service Rig	3.9
Survey	15.0
Trucking & Misc. Transportation	2.0
Logging (Cased Hole) & Perforating	12.2
Tubing & Attachments	7.7
Pumping Equipment	18.8
Wellhead	4.0
Other Equipment & Services	1.0
Engineering, Supervision & Admin.	4.9
Completion Subtotal	69.5
Completed Producer Total	275.7
Contingencies @ 15%	41.3
Total	317.0
<u>**Formation Evaluation**</u>	
On-site & Long-term Desorption Test	25.0
Wireline Services	22.5
Coring Costs	15.0
Contingencies @ 15%	9.4
Total	71.9
GRAND TOTAL STAGE 1.2	388.9

Stage 1.3 Micro-Pilot Testing

	$ US '000
Stimulation & Treatment	90.0
Initial Production Test	
Gas Chromatography and Analysis	2.4
Production Test Crew & Equipment	18.0
Supervision	7.5
Subtotal	27.9
Gas Injection	
Carbon Dioxide	25.0
Trucking and Injection	20.0
Pump Pulling	1.8
Supervision	7.5
Subtotal	54.3
Post-Injection Production Testing	
Gas Chromatography and Analysis	3.6
Production Test Crew & Equipment	35.0
Pump Pulling	1.8
Supervision	7.5
Subtotal	47.9
Contingencies @ 15%	33.0
GRAND TOTAL STAGE 1.3	253.1

Stage 1.4 Data Analysis & 5-Spot Pilot Design

	$ US '000
Data Analysis & Reporting	21.0
Reservoir Modelling of Field Results	30.0
Project Assessment & Economics	9.0
TOTAL STAGE 1.4	60.0

Summary Stage 1 Costs

	\$ US '000
Stage 1.1 Field Review	30.0
Stage 1.2 Formation Evaluation Well Drilling and Evaluation	388.9
Stage 1.3 Micro-Pilot Testing	253.1
Stage 1.4 Data Analysis & 5-Spot Pilot Design	60.0
Total	**732.0**

5-Spot Pilot Testing

The 5-spot pilot involves drilling four additional wells (one producer and three injection wells), converting the micro-pilot well to an injector, construction of a surface facility, injection of CO_2 and flue gas, production testing, data analysis and project design. In the full field pilot, approximately 15,000 tonnes of CO_2 (or flue gas) are injected over six months. The CO_2 (or flue gas) will be generated by exhaust from a propane-fueled compressor supplemented by trucked CO_2, prior to injection. The injection/production operation will run continuously for at least 6 months. The entire stage will require roughly two years to complete.

We have estimated capital cost for the 5-spot pilot at about \$ US 5.4 million and operating cost at about \$US 1.3 million, for a total cost of \$US 6.7 million, prior to cost recovery for the sale of the compressor and CO_2/flue gas generator (estimated at 50% of cost or US\$ 1.5 million). Therefore, the total net cost for the 5-spot pilot is estimated to be \$US 5.2 million, as shown in **Table 9.2**. Details of the capital and operating cost estimate for the 5-spot pilot are contained in Appendix IV-A.

Table 9.2: Cost Estimate for a 5-Spot Pilot Test at the Jincheng Field, South Qinshui Basin

	\$ US '000
Stage 2.1 2nd Well Drilling & Completion	388.9
Stage 2.2 2nd Well N_2/CO_2 Micro-Pilot Testing	253.1
Stage 2.3 Conversion of first two wells to injection Wells	120.0
Stage 2.4 Production Well Drilling & Completion	463.6
Stage 2.5 Pre-Injection Production	27.9
Stage 2.6 Remaining 2 Injection Wells Drilling & Completion	636.4
Stage 2.7 Surface Facility Construction	3,814.6
Stage 2.8 Injection & Production	690.0
Stage 2.9 Final Testing	47.9
Stage 2.10 Analysis & Expansion Design	300.0
Total	**6,742.3**

Capital and Operating Cost Breakdown	**$ US '000**
Capital (Stages 2.1, 2.3, 2.4, 2.6 and 2.7)	5,423.5
Operating (Stages 2.2, 2.5, 2.8, 2.9 and 2.10)	1,318.9
Total	**6,742.4**
Less 50% cost recovery of compressor and flue gas/CO_2 generator	1,509.0
Stage 2 Total (net)	**5,233.4**

9-Pattern Testing (Commercial Demonstration)

It should be clear from the 5-spot pilot test whether a larger scale effort is warranted. If so, eight additional patterns can be installed surrounding the 5-spot pilot. It is very difficult to estimate the cost of the commercial demonstration at this time, because we do not have the 5-spot pilot reservoir performance data. The injection rate, injection pressure, source of CO_2, produced well stream production rate, gas composition etc. would greatly impact on the surface facility design and cost. From the operation perspective, the sales of the methane gas can probably offset some of the operating costs. A rough estimate for the commercial demonstration stage is of the order of $US 40 million not considering the sale of methane.

9.3 Hypothetical Commercial ECBM Project at Jincheng, South Qinshui Basin

Initially ECBM projects will likely occur at the conventional CBM project sites, due to the presence of existing infrastructure, which greatly reduces the investment risk. Therefore, our economic analysis assumes that land permits, micro-pilot, 5-spot pilot and 9 pattern demonstration testing have been completed for the hypothetical ECBM project site.

The Jincheng site is located approximately 1,000 km to the south and east of Beijing, in the southeast district of the Qinshui Basin. The Jingcheng area occupies an area of 406 km^2 (40,600 ha.). Gas in place is estimated at 99 Gm^3 (3.5 Tcf). Resource concentration is 244 Mm^3/km^2. Our economic analysis assumes an ECBM project, which encompasses 6,475 hectares or approximately 16% of the prospective area. It is a small portion, approximately 7% of the total area of the Qinshui Basin (5,560 km^2).

A significant cost of an ECBM project will be in the capture, purification, compression and transportation of the CO_2 from the coal-fired generation plant to the project site. The CO_2 supply cost is dependent on the CO_2 concentration in the flue stack, capture/separation process selected, compression requirements and distance to the ECBM project site. Therefore, for easier interpretation, our economic analysis assumes a high quality CO_2 at pipeline pressure (8,275 kPag) would be available at the project site at zero cost. Our analysis compares the economic costs/benefits of ECBM projects versus conventional CBM projects in the Qinshui Basin, at various constant plant-gate gas prices. These results were then used to determine an affordable CO_2 cost/credit for ECBM projects so that it can compete with conventional CBM projects.

9.3.1 Reservoir Parameters Assumption

The evaluation of the economic viability of ECBM projects in China requires a reservoir model based on the local geology, engineering practice and operations. However, a lack of available data makes this process difficult.

Following a review of some of the Jincheng project and geology associated with potential acreage, the Australian reservoir model was considered reasonable for the Qinshui Basin. The Jincheng reservoir model assumes a project with prospective CBM coals measures at a modest depth of 650 metres. The Qinshui coals range from high volatile bituminous to anthracite and are assumed to be normally pressured and gas saturated.

A range of depth to prospective coal horizons does occur with CBM exploration in the Jincheng field, Qinshui Basin. An average depth of 650 metres was selected after a review of the available CBM reservoir data for the Jincheng project. Prospective coal measures are present at this project from 300 to 1,000 metres, with as many as 21 seams present. A total of 16 wells have been drilled and completed at this project by China United Coalbed Methane Co. Ltd. (CUCBM), with initial gas rates ranging from 3 to 16 $10^3 m^3$ per day per well. However, insufficient data did not allow us to prepare a relationship of gas content and permeability variations to depth.

A range of well spacing was considered, from 32 to 129 hectares, for the Qinshui Basin reservoir model. It should be noted that, well spacing for any project is a function of productivity, capital requirements, useful life of production facilities and ultimately project economics. A well spacing of 32 hectares would result in significant additional capital costs for the drilling of producers (100% increase) and injectors (50% increase). While a 129-hectare well spacing results in significant capital cost reductions for the drilling of producer and injector wells, it also provides reduced project productivity and a very long project life (> 40 years). It is determined that 64 hectare well spacing is a reasonable assumption for the Qinshui Basin reservoir model.

The choice of a production profile for the China site was a difficult one, as limited public data was available on the reservoir properties of coals in the Jincheng field in the South Qinshui Basin. However, there are similarities between the China site and the Australia site.

- Coal measures in the Jincheng area range from 10 to 15 metres at depths of 300 to 1,000 metres. The coal thickness used in the Australian model was 9 metres at an assumed depth of 650 metres.
- Permeability in the Jincheng coals ranges from 0.1 to 7 md, based on limited well-testing data and history matched models. The average coal permeability used in the Australian model was assumed to be 5 md.
- Gas content in the Jincheng coals ranges from 12 to 26 m^3 per tonne. The average gas content used in the Australian model was assumed to be 9 m^3 per tonne.
- Initial production rates in the Jincheng coals ranges from 2.5 to 6.5 10^3 m^3 per well. The average initial gas rate used in the Australian model was assumed to be 4.2 10^3 m^3 per well.

In summary, the interpretation of the limited data seems to suggest that the Australian reservoir model was a reasonable assumption for the Jincheng field, due to similar coal thickness and depth ranges, slightly lower permeability but higher average gas content as well as similar initial production rates. Also, the use of a common reservoir model has an added advantage as it allows for the comparison of ECBM projects in the two countries, given different-currency, gas prices, capital and operating costs, royalty and tax regimes.

Consequently, the CBM reservoir and project parameters for the Australia project were considered reasonable for the Qinshui Basin conventional and ECBM projects and are listed in **Table 9.3**.

Table 9.3: CBM Reservoir and Project Parameters

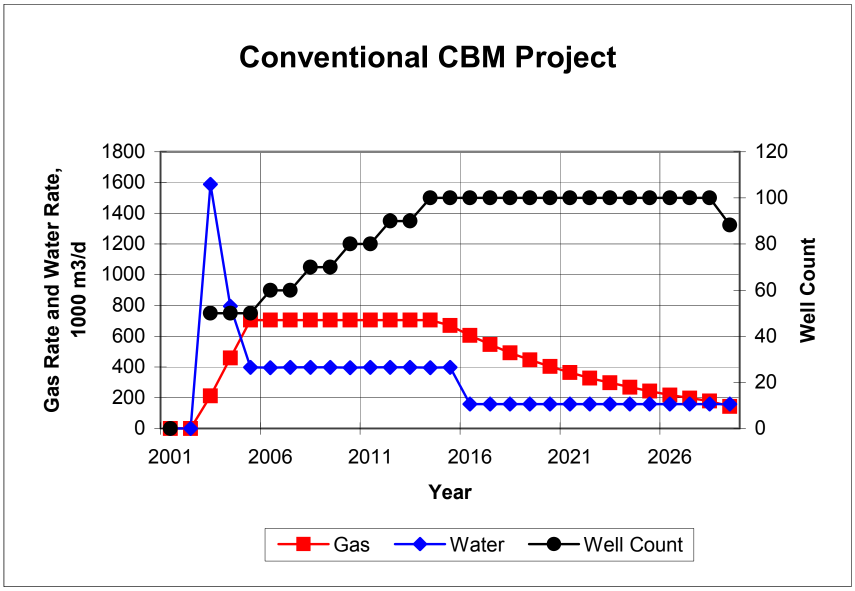
Development Case	Conventional	ECBM
Average coal seam depth	650 m	650 m
Net coal pay	9 m	9 m
Coal methane content (saturated)	8.9 cc/gm	8.9 cc/gm
Initial reservoir pressure	5,930 kPa	5,930 kPa
Reservoir temperature	32°C	32°C
Abandonment reservoir pressure	1,380 kPa	1,380 kPa
Specific Gravity	1.4	
Coal absolute permeability	5 md	
Initial well rate	4.2 $10^3m^3/d$	4.2 $10^3m^3/d$
Plateau well rate	14 $10^3m^3/d$	24 $10^3m^3/d$ (CO_2) and 35 $10^3m^3/d$ (flue gas)
Gas-water ratio (initial)	7.5 $m^3/10^3m^3$	7.5 $m^3/10^3m^3$
Derived		
CBM gas in place	1,479 $10^3m^3/ha$	1,479 $10^3m^3/ha$
CBM OGIP per well	95 10^6m^3	95 10^6m^3
Recovery factor	50%	80%
Project CBM reserves	4.8 10^9m^3	7.7 10^9m^3
CO_2 or flue gas sequestered	0	15.3 10^9m^3
Number of producing wells	100	100
Number of CO_2 injection wells	0	81
Producer well spacing	64 ha	64 ha
Acreage	6,475 ha	6,475 ha

9.3.2 Production Forecasts

Conventional Project

The conventional CBM project is projected to require 50 CBM producing wells initially with a further 50 wells drilled in subsequent years. The first-year average production rate will be 210 10^3m^3 per day (4.2 10^3m^3 per day per well), with a maximum rate of 704 10^3m^3 per day (14 10^3m^3 per day per well) in the third year, sustained for a further 10 years through drilling, before declining to the economic limit **(Figure 9.1)**.

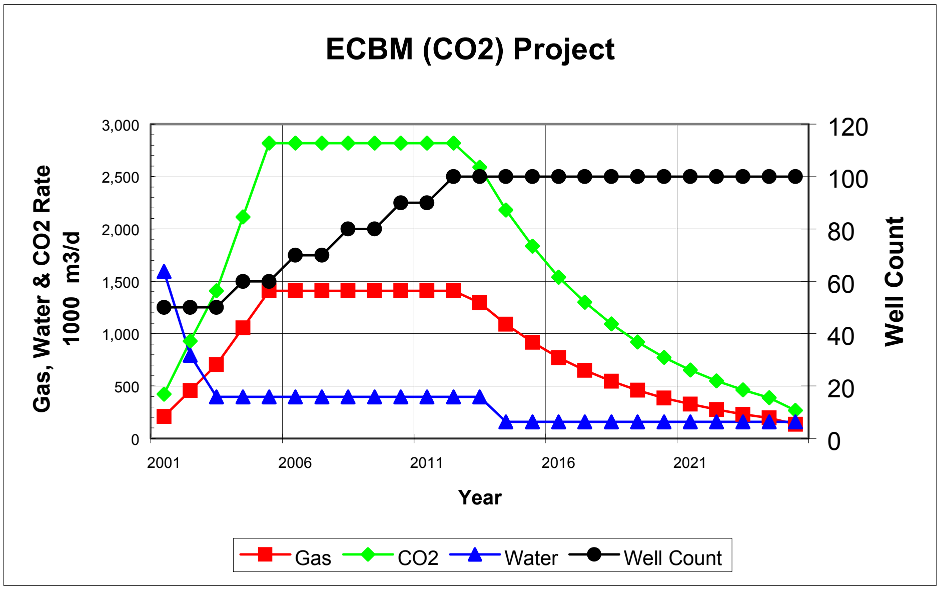
Figure 9.1 Gas and Water Production Rates



ECBM (CO_2) Project

The ECBM (CO_2) project is projected to require 50 CBM producing wells plus 40 CO_2 injection wells initially with a further 50 wells and 41 CO_2 injection wells drilled in subsequent years. The project will achieve a first-year average production rate of 210 10^3m^3 per day (4.2 10^3m^3 per day per well) with a maximum rate of 1,410 10^3m^3 per day (24 10^3m^3 per day per well) in the fifth year, sustained for a further 8 years through drilling before declining to the economic limit **(Figure 9.2).** The increased productivity per well (10 10^3m^3 per day per well) is estimated from a review of the CO_2 displacement process that has been operated by Burlington Resources at the Allison Unit in the San Juan Basin in northern New Mexico.

Figure 9.2 ECBM (CO_2) Project

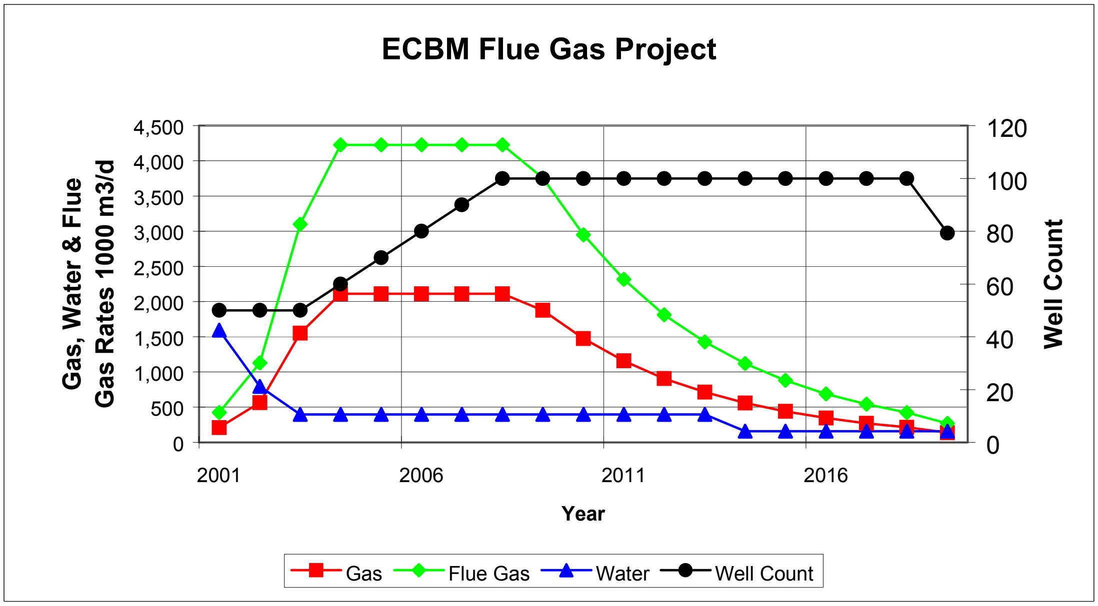


The ECBM project will inject 422 10^3m^3 per day (10.6 10^3m^3 per day per well) of CO_2 initially, with a maximum injection of 2,810 10^3m^3 per day (34.7 10^3m^3 per day per well) in the third year and sustained for 8 years. Subsequently, the CO_2 injection decline is based on a 2:1 ratio of the CBM gas production. The total volume of CO_2 sequestered will be 15.3 10^9m^3 during the life of the project, assuming a 2:1 displacement ratio of CO_2 to methane for the project. The amount of CO_2 sequestered during the life of the ECBM project is estimated to be 28.6 million tonnes.

ECBM (Flue Gas) Project

The ECBM (flue gas) project is projected to require 50 CBM producing wells plus 40 flue gas injection wells initially with a further 50 wells and 41 flue gas injection wells drilled in subsequent years. The project will achieve a first-year average production rate of 210 10^3m^3 per day (4.2 10^3m^3 per day per well) with a maximum rate of 2,114 10^3m^3 per day (35 10^3m^3 per day per well) in the fifth year, sustained for 5 years through drilling before declining to the economic limit **(Figure 9.3).** The increased productivity per well (21 10^3m^3 per day per well) compared to a conventional well is anticipated due to the flue displacement process (combination of N_2 and CO_2). The ability of N_2 to displace adsorbed methane has been observed at Amoco's ECBM pilot project (N_2 injection) in the San Juan Basin in northern New Mexico. The pilot production increased from a pre-injection rate of 7 10^3m^3 per day up to 34 10^3m^3 per day (500% increase, compared to **Figure 1.1**).

Figure 9.3 ECBM Flue Gas Project



It is likely that the flue gas will need to be composed of a higher percentage of CO_2 than N_2, throughout the life of the ECBM project. The N_2 component is used to accelerate methane displacement in the near cleat area and improve early productivity, while the CO_2 component improves the overall displacement efficiency and ultimate methane recovery. The N_2 concentration will likely be higher in the early phases of injection and decrease with time. An average injection for the life of the ECBM (flue gas) project could be in the order of CO_2 (80%) and N_2 (20%).

The ECBM (flue gas) project will inject 423 10^3m^3 per day (10.6 10^3m^3 per day per well) of flue gas initially, with a maximum injection of 4,225 10^3m^3 per day (52.2 10^3m^3 per day per well) in the third year and sustained for a further 5 years. Subsequently, the flue gas injection decline is also based on a 2:1 ratio of the CBM gas production. The total volume of flue gas sequestered will be 15.3 10^9m^3 during the life of the project, assuming a 2:1 displacement ratio of flue gas to methane for the project. The amount of CO_2 sequestered during the life of the ECBM project is estimated to be 22.9 million tonnes, assuming 80% CO_2 average in the injected volumes. It should be noted that as the nitrogen content in the flue gas increases, the displacement ratio decreases. Typically, for a 100% nitrogen injection, 0.5 to 1 volume of nitrogen is adsorbed for each volume of methane displaced. This would impact positively on the economics. The extent of the variation of this parameter will be verified in the pilot testing with flue gas by varying the CO_2/N_2 composition in the injection gas. For this simple analysis, it is assumed that the 2 to 1 ratio stays the same at 80% CO_2 and 20% N_2.

Breakthrough of N_2 to the producing wells will occur. To minimize this, a high CO_2/N_2 average injection ratio was chosen. It is assumed in this analysis that minimal N_2 breakthrough can be tolerated by blending of various production streams to pipeline specifications, thus avoiding the requirement for expensive N_2 rejection.

9.3.3 Capital Costs

ECBM Project

Our hypothetical ECBM project involves the drilling and completion of 100 producers and 81 injectors, based on a 5-spot development plan. The CO_2 or flue gas will be generated by exhaust from a coal-fired generation plant, prior to injection. Total well costs to drill either a CBM or CO_2 injection well, were estimated based on anticipated costs for a large project. It was assumed that CBM wells and CO_2 injection wells would require a hydraulic fracture-stimulation. The capital costs are set out below in **Table 9.4**.

Table 9.4: Drilling and Completion Costs

	Estimated Cost US$ '000/Well
Production/injection wells (drilling and completion, to 650 metres total depth; excluding fracture stimulation)	325/225
Hydraulic fracturing	90
Total	**$415/315**

The production facilities and field infrastructure requirements for this project are based on a CBM producing well spacing of 64 ha, which dictates the costs for flowlines, satellite separation, metering stations and gathering lines. The raw gas production will require treating and compression prior to entering the high-pressure transmission line. The removal of CO_2 will be required for both the conventional and ECBM projects, unless the gas is used locally. The removal of N_2 will be required in the flue gas project. However, due to the staged drilling program, the opportunity will exist to blend producing wells with varying N_2 and/or CO_2 levels, to meet or minimize the size of the facilities. A high-pressure transmission line requirement was taken into account for the compression required (745 KW). Capital costs for the project were estimated and are presented in **Table 9.5.**

Table 9.5: Production Facilities and Field Infrastructure Costs

	Conventional Well $US '000/Well	Injection Well $US '000/Well
Flowlines	60	12
Gas gathering lines	30	30
Gas delivery line	6	6
Satellite stations	24	6
Gas treatment and compression facilities	60	0
Engineering, administration and management @ 10%	20	6
Total	**$200**	**$60**

9.3.4 Operating Costs

Operating costs are categorized as fixed and variable costs, a cost for well workovers has been included in the monthly fixed costs. Gas turbine-drive compressors have been assumed with gas shrinkage of 5 percent deducted from the CBM production available for sale. Costs for water treatment and disposal have been included, though a common practice in the Qinshui Basin may be for individual well evaporation ponds. Our analysis assumes similar monthly well operating costs for either the conventional or ECBM well. No additional costs were added for gas treating for the ECBM project. The details of the operating cost assumptions are contained in **Table 9.6.**

Table 9.6: Operating Costs

	Conventional and ECBM Cases Estimated Cost
Production—fixed costs - Operations (producer or injector) - Administration, engineering and management	$US 900/Well-Month
Production—variable costs - Compression - Gas Treating - Water disposal	 $US 3.55/$10^3m^3$ $US 1.77/$10^3m^3$ $US 0.94/ m^3

9.3.5 Financial and Fiscal Terms

Gas prices were interpreted to vary with terms and conditions, however project economics were prepared for constant plant-gate prices ranging from $US 0.50 to $US 3.00/GJ. The heating value of dry natural gas is taken as 37.23 GJ/10^3 m^3.

Royalty in China's CBM production is 0 % of the wellhead gross revenue below 1.0 $10^9 m^3$ per year. However, China does have a 5 % value added tax ("VAT"), charged at the wellhead with no allowed deductions. The corporate income tax rate is 33%, after allowing for straight-line depreciation over 8 years for all development expenditures. The financial and fiscal terms are set out in **Table 9.7.**

Table 9.7: Financial and Fiscal Terms

Plant gate gas price (constant)	$US 0.50 to $US 3.00/GJ
Royalty and VAT	5 %
Depreciation life (on development costs)	8 years
Income tax rate	33%

9.4 Economics Analysis

The economic results for the conventional CBM and ECBM projects are based on the project development plan, capital and operating costs and fiscal terms set out above.

Conventional CBM Project

The economic analysis of the conventional CBM project indicates that the minimum constant plant-gate gas price required to achieve a 10% rate-of-return, after income taxes, is approximately $US 1.25 per GJ. The project payout period is 9 years with a rate-of-return of 13%, on a before tax basis. Appendix IV-B presents the economic results for constant plant-gate gas prices ranging from $US 0.50 to $US 3.00 per GJ.

ECBM (CO_2) Project

The economic analysis of the ECBM (CO_2) project indicates that the minimum constant plant-gate gas price required to achieve a 10% rate-of-return, after income taxes, is approximately $US 1.05 per GJ, assuming no cost for CO_2 (high quality and compressed) at the project site. A number of coal-fired generation and industrial plants in the vicinity of the Jincheng field may be a source of CO_2. The project payout period is estimated to be 8 years with a rate-of-return of 13%, on a before tax basis. A cashflow projection of the ECBM (CO_2) Project for the $US 1.46 per GJ plant-gate gas price case is shown in **Table 9.8**. Appendix IV-C presents the economic results for constant plant-gate gas prices ranging from $US 0.50 to $US 3.00 per GJ.

Table 9.8 Projected 20 Year Cash Flows for a CO_2 ECBM Project under a $US 1.46/GJ Gas Price

Summary Report
Case: Qinshui Basin - ECBM (CO2) - $1.46

Net Present Values

Disc Rate (%)	Before Tax Oper Inc. M$	Before Tax Cap. Inv. M$	Before Tax Cash Flow M$	After Tax Cash Flow M$
0	286,205	86,735	199,471	125,238
6	169,124	72,456	96,668	58,304
8	143,129	69,079	74,050	42,505
10	122,057	66,194	55,864	29,652
12	104,907	63,715	41,192	19,201
14	90,860	61,576	29,285	10,672
Arr:	286,205	86,735	199,471	125,238

Case Description
Qinshui Basin, China
Enhanced Coalbed Methane Case
CO2 Sequestration Project
100 Producing Well Development
81 CO2 Injection Wells
160 Acre Spacing

Global:	Default
Model:	China CBM
Currency:	U.S. Dollar
Discount Date:	2000/01
Evaluation Date:	2000/01

Economic Indicators

		B.Tax	A.Tax
ROR	%	21.7	17.2
Payout Period	Stnd. (mo's)	74	80.4
	Proj. (mo's)	87.8	98.2
Undisc. PIR	$/ $	2.3	1.44
8.0 Pcnt. PIR	$/ $	1.07	0.62
12.0 Pcnt. PIR	$/ $	0.65	0.3
NPV/Vol @ 8.0	$/E6m3	9.66	5.55
NPV/Vol @ 12.0	$/E6m3	5.38	2.51
Economic Limit Date		2049/07	

Products Recovery

		Gross	WI
Oil	E3m3	0	0
Gas-Raw	E6m3	7,663	7,663
Gas-Sales	E6m3	7,280	7,280
Ethane	E3m3	0	0
Propane	E3m3	0	0
Butane	E3m3	0	0
Cond.	E3m3	0	0
Sulphur	E3t	0	0
Other	E6m3	15,327	15,327

Company WI

	Initial %	Final %
Working	100	100
Oil	100	100
Gas	100	100
Byprod.	100	100
Other	100	100
Capital	100	100
Royalty	100	100

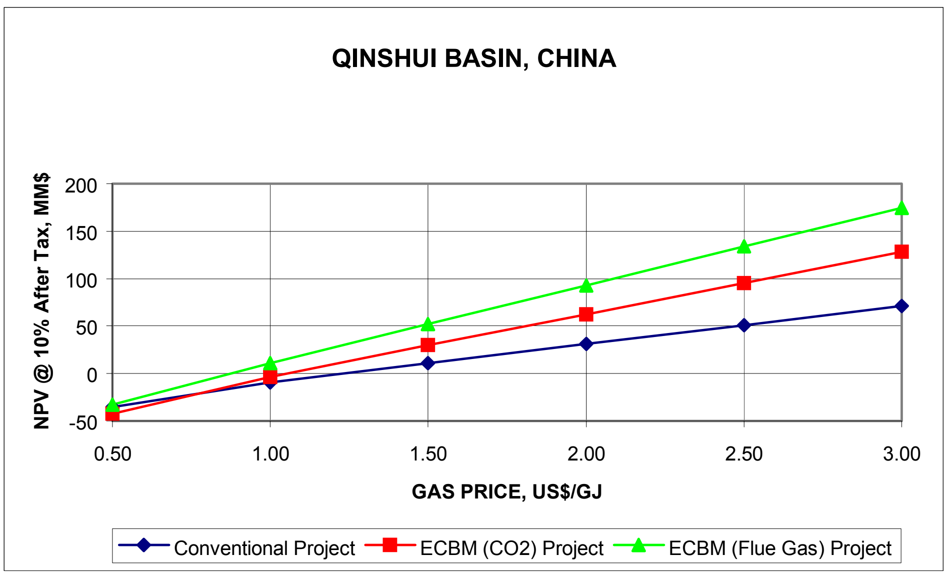
Date	Number of Wells	Gas Raw Volume E6m3	Gas Sales Volume E6m3	Water Volume E3m3	Injected Gas Volume E6m3	Gas Price $/GJ	Revenue M$	Operating Costs M$	Gas Royalty M$	Operating Income M$	Capital M$	Before Tax Cash Flow M$	Income Taxes M$	After Tax Cash Flow M$
2000(12)	0	0	0	0	0	1.46	0	0	0	0	42,435	-42,435	0	-42,435
2001(12)	50	77	73	581.9	154	1.46	4,011	1,497	201	2,313	0	2,313	0	2,313
2002(12)	50	167	159	290.2	339	1.46	8,691	1,702	435	6,555	0	6,555	0	6,555
2003(12)	50	257	244	145.1	514	1.46	13,370	2,044	669	10,658	8,430	2,228	922	1,306
2004(12)	60	387	367	145.1	773	1.46	20,111	2,842	1,006	16,264	0	16,264	3,215	13,049
2005(12)	60	514	488	145.5	1,028	1.46	26,741	3,520	1,337	21,884	10,580	11,304	4,665	6,639
2006(12)	70	514	488	145.1	1,028	1.46	26,741	3,628	1,337	21,776	0	21,776	4,654	17,122
2007(12)	70	514	488	145.1	1,028	1.46	26,741	3,628	1,337	21,776	8,430	13,346	4,333	9,013
2008(12)	80	516	490	145.1	1,031	1.46	26,814	3,743	1,341	21,730	0	21,730	4,293	17,437
2009(12)	80	514	488	145.5	1,028	1.46	26,741	3,736	1,337	21,668	8,430	13,238	5,633	7,604
2010(12)	90	514	488	145.1	1,028	1.46	26,741	3,844	1,337	21,560	0	21,560	5,635	15,925
2011(12)	90	514	488	145.1	1,028	1.46	26,741	3,844	1,337	21,560	8,430	13,130	5,635	7,495
2012(12)	100	516	490	145.1	1,031	1.46	26,814	3,959	1,341	21,514	0	21,514	5,620	15,894
2013(12)	100	473	449	145.5	945	1.46	24,582	3,731	1,229	19,621	0	19,621	5,432	14,190
2014(12)	100	398	378	58	796	1.46	20,693	3,251	1,035	16,407	0	16,407	4,371	12,036
2015(12)	100	335	318	58	670	1.46	17,419	2,916	871	13,632	0	13,632	3,803	9,829
2016(12)	100	282	268	58	564	1.46	14,664	2,635	733	11,296	0	11,296	3,032	8,264
2017(12)	100	237	225	58.2	474	1.46	12,344	2,397	617	9,329	0	9,329	2,731	6,598
2018(12)	100	200	190	58	399	1.46	10,391	2,197	520	7,674	0	7,674	2,185	5,489
2019(12)	100	168	160	58	336	1.46	8,747	2,029	437	6,281	0	6,281	2,073	4,208
Sub.		7,097	6,742	2,817.40	14,197		369,097	57,144	18,455	293,498	86,735	206,763	68,232	138,531
Rem.		566	538	348.5	1,129		29,453	35,272	1,473	-7,292	0	-7,292	6,002	-13,294
Total		7,663	7,280	3,165.90	15,327		398,550	92,416	19,927	286,206	86,735	199,471	74,233	125,237

ECBM (Flue Gas) Project

The economic analysis of the ECBM (flue gas) project indicates that the minimum constant plant-gate gas price required to achieve a 10% rate-of-return is approximately $US 0.90 per GJ, assuming no cost for flue gas (injection quality and compressed) at the project site. A number of coal-fired generation and industrial plants in the vicinity of the Jincheng field may be a source of flue gas. The project payout period is estimated to be 5 years with a rate-of-return of 14%, on a before tax basis. Appendix IV-D presents the economic results for constant plant-gate gas prices ranging from $US 0.50 to $US 3.00 per GJ.

Figure 9.4 presents the economic results for both the conventional and ECBM projects for net present values at 10% after taxes versus constant plant-gate gas prices.

Figure 9.4 Conventional versus ECBM Projects



CO_2 and Flue Gas Costs at the Project Site

An analysis was completed to determine the affordable price of CO_2 and flue gas sources at the plant-gate for various constant gas prices. Thus determining the maximum cost of CO_2 and flue gas, which could be charged for capture/separation, compressing and transporting the CO_2 to the project site and still allows the operator to achieve a similar net present value, after taxes, as compared to a conventional CBM project. In other words, the affordable price of CO_2 is the maximum price that the CO_2-ECBM project can afford to pay for the CO_2 while attaining the same net present value as the conventional CBM project.

Figures 9.5 and 9.6 present the allowable CO_2 and flue gas cost in $US per tonne versus constant plant-gate gas prices. For example, the affordable prices for the CO_2 and flue gas at plant-gate gas price of $US 1.50/GJ are $US 3.00 and $US 5.00/tonne, respectively. This price is not sufficient to cover the full cost of capture/separation and compression of the CO_2 and delivery to site. This cost is estimated at about $US 25 – 35/tonne for recovering

CO_2 from coal-fired power plant flue gas using an amine separation process. A substantial credit would be needed for disposing of waste CO_2 in order to make this attractive.

Figure 9.5 CO_2 and Flue Gas Cost – Plant Source to ECBM Project (US \$/tonne)

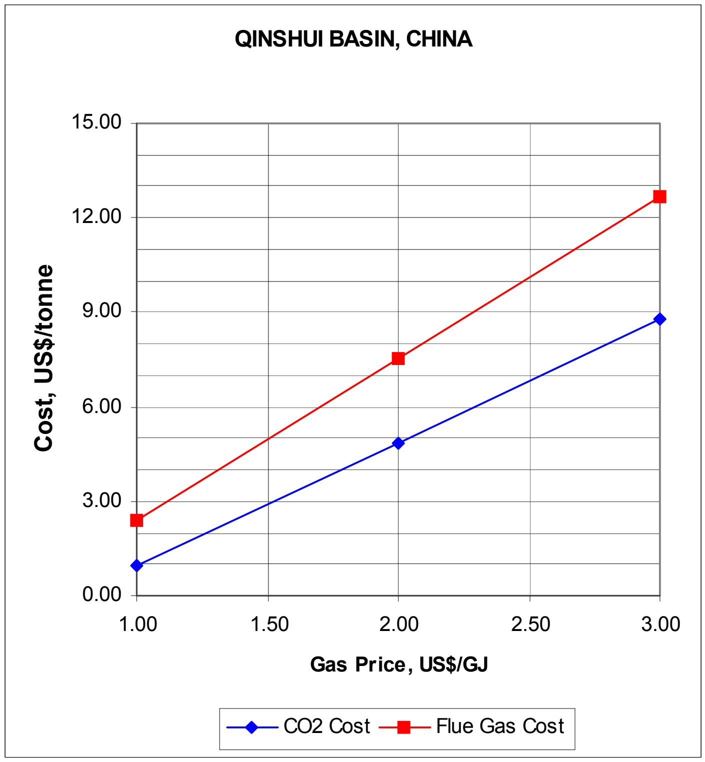
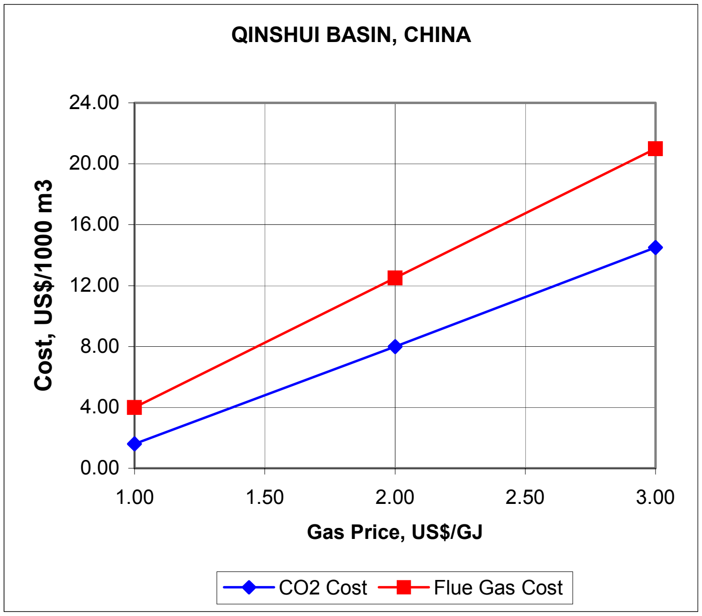


Figure 9.6 CO_2 and Flue Gas Cost – Plant Source to ECBM Project (US\$/10^3m^3)



9.5 Net CO_2 Sequestered

Similar to the Australia project, the total volume of the CO_2 injected during the life of the hypothetical commercial CO_2-ECBM project in China will be 15.3 10^9m^3. Assuming no CO_2 breakthrough during the project total CO_2 sequestered will be about 28.6 million tonnes. To calculate the CO_2 avoided or net CO_2 sequestered, we will use the same example in Wong et al., (2000), which calculates that net sequestered CO_2 volume as approximately 65% of the injected CO_2 volumes. Note that the actual calculation would require more engineering details, as it is process dependent and fuel dependent. On this basis, our hypothetical development in the Qinshui Basin has provided a net CO_2 sequestering of approximately 18.6 million tonnes for the ECBM (CO_2) project and 14.9 million tonnes for the ECBM (flue gas) project.

9.6 Economic Comparison between the Australia Site and China Site

Demonstration Pilot Plant Costs

The following is a summary of the three stages of the demonstration pilot plant cost estimates for the Dawson River site, south Bowen Basin in Australia and the south Qinshui Basin site in China.

$ US Million	**Australia Site, South Bowen Basin**	**China Site, South Qinshui Basin**
Stage 1: Micro-Pilot Testing	0.67	0.73
Stage 2: 5-Spot Piloting Testing (net cost is after 50% cost recovery of compressor and flue gas generator)	6.2 (net 4.8)	6.7 (net 5.3)
Stage 3: 9 Patterns 5-Spot Testing	35	40

Comparison of the cost estimates suggests that the demonstration pilot plant costs for the China site (for all three stages) are generally10% higher than the Australia site. While surface facility and testing costs are roughly the same, drilling and completion costs are about 30% higher in China. The difference can be explained by the general accessibility of drilling rigs and the costs of well drilling and completion services for the two sites and the fact that for the Australia site, we can take advantage of mineral rigs that are available in the south Bowen Basin rather than using conventional oil rigs, which is the case for the China site. The Qinshui Basin is not as accessible as the Bowen Basin. However, as more service company competition or large-scale projects are being implemented in the Qinshui Basin, this would lower the drilling and completion costs.

Liquid CO_2 supply for the micro-pilot testing does not appear to be a problem, as both sites are accessible to tanker trucks and pumping equipment. However, the costs of delivering the CO_2 to site can be highly variable, as transportation costs could be substantial, depending on the location of the liquid CO_2 supply source.

Cost Assumptions for the Hypothetical Commercial ECBM Project

- Drilling and completion costs are about 30% higher for the China project than the Australia project
- Surface facility costs are roughly the same
- Operating Costs are the same
- Fiscal Regime seems more favorable in China than Australia
  - Royalty and VAT 5% versus 10%
  - Depreciation over 8 years versus 15 years
  - 33% income tax rate versus 36%

Comparative Economics

The following is a summary of breakeven gas prices in \$ US /GJ, to achieve a 10% return, after income tax for the Australia project and China project.

\$ US /GJ	**Australia Project, South Bowen Basin**	**China Project, South Qinshui Basin**
Conventional CBM	1.10	1.25
ECBM (CO_2)	1.00	1.05
ECBM (Flue Gas)	0.90	0.90

- For Conventional CBM, the breakeven gas price in China is higher (\$ US 1.25 versus \$ US 1.10/GJ), because of the higher capital costs with respect to drilling and completion costs.
- For CO_2 and flue gas ECBM projects, the China economics are improving at a more rapid rate than Australia. This is due to the effect of a better financial and fiscal regime in terms of a lower royalty rate, lower income tax rate and more rapid depreciation. For the flue gas ECBM project, the economics between China and Australia are equal. This suggests that the fiscal regime for China is more favorable to incremental production economics such as the enhanced recovery of CBM.

Affordable Price for CO2 and Flue Gas and Net CO_2 Sequestered

The following is a summary of affordable prices of CO_2 and flue gas for the Australia and China projects at a gas price of \$ US 1.50/GJ, together with the estimates of net CO2 sequestered during the life of the project.

	Australia Project, South Bowen Basin	**China Project, South Qinshui Basin**
Affordable Price @ \$ US 1.50/GJ		
CO_2	\$ US 2.35/t	\$ US 3.00/t
Flue Gas	\$ US 3.80/t	\$ US 5.00/t
CO_2 Injected during the Life of Project	28.6 Mt	28.6 Mt
Net CO_2 Sequestered		
CO_2-ECBM	18.6 Mt	18.6 Mt
Flue Gas – ECBM	14.9 Mt	14.9 Mt

Affordable price of CO_2 is the maximum price that the CO_2-ECBM project can afford to pay for the CO_2 while attaining the same net present value as the conventional CBM project. At the higher gas prices, the affordable price for CO_2 and flue gas will be higher.

- Under the same gas price, the China project produces a higher affordable price for the CO_2 and flue gas than the Australia project. This suggests better incremental production economics in China, because of a more favorable financial and fiscal regime.
- In terms of CO_2 injected and net CO_2 sequestered, both cases are the same, reflecting the same injection and production profile assumed for the analysis.

9.7 Conclusions

- The potential for CO_2 sequestration in the Qinshui Basin is significant. However, the cost to capture, purify, compress and transport CO_2 to an ECBM project site can be substantial. It depends on the concentration of CO_2 in the flue gas and the required purity of the injection CO_2. Hence, the project would require a CO_2 emission credit to achieve comparable economic results to conventional CBM developments.

- Initially ECBM projects will likely occur in conjunction with existing conventional CBM projects, due to the presence of an established infrastructure, which greatly reduces investment risk. Capital costs for drilling and infrastructure in the Qinshui Basin could be reduced with additional service competition or larger scale projects. A reduction in capital costs would increase the allowable CO_2 costs landed at the project site.

- The economic analysis assumes a 2:1 ratio of CO_2 injected to CH_4 produced. This ratio is based on lab-measured isotherm, rather than actual field test. As this ratio would impact greatly on the economics, the economic analysis should be re-visited when the new data are available from field measurements.

- The use of flue gas or varying combinations of CO_2 and N_2 in an ECBM project would likely result in a faster release of methane to the producing wells and thereby improve the economics results at lower gas prices. Additional research into the optimum percentages, at various stages of the project life, is required to better understand the potential for this process.

9.8 References

IEA GHG, 1998, Enhanced Coalbed Methane Recovery with CO_2 Sequestration. Programme Report Number PH3/3, 139 pages.

Wong, S., Gunter, W.D., and Mavor, M.J., 2000. Economics of CO_2 Sequestration in Coalbed Methane Reservoirs, Proceedings of 2000 SPE/CERI Gas Technology Symposium, April 3-5, Calgary, Alberta. SPE Paper 59785, 8 p.

CHAPTER 10:
IMPLEMENTATION ISSUES

10.1 Introduction

From a pragmatic point of view, energy companies are looking for the cheapest way to produce the coalbed methane (CBM), i.e. primary recovery. They will not be looking for enhanced recovery until the primary recovery route is exhausted. Advanced drilling technique such as tight radius drilling might be an alternative. It has the promise of greatly increasing the contact with the reservoir (hence higher production rate). The issue here is cost; the well will be drilled at a much higher cost. The question is whether the higher drilling costs justify the higher production rate. A strategy to implement the ECBM process might be to work with the energy company early on at the primary recovery level and find the situation that CO_2 enhancement can improve the CBM economics and recovery.

The economic analysis in Chapters 8 and 9 suggests that the ECBM process can recover substantial incremental methane at a cost comparable to primary production, provided that the CO_2 or flue gas can be delivered to the field plant-gate at an "affordable price". It is found that the affordable price for the injection gas ranges from less than $ US 0 to $ US 12/tonne, for a range of plant-gate methane gas prices from $ US 0.50 to $ 3.00/GJ. This is far lower than the cost required to capture/separate, compress and transport the CO_2 or flue gas to the field, which is estimated at $ US 20 – 35/tonne CO_2 for recovering CO_2 from a coal-fired power plant flue gas using current amine separation technology. For this process to be economically viable the cost of CO_2 capture must be lowered or there must be a credit for the CO_2 sequestered.

With this in mind, in order to implement the ECBM project, a number of specific issues must be addressed. They are:

- Secured CO_2 supply, which is critical to the success of the ECBM process;
- Government policy on CO_2 reduction crediting, whereby a value for the CO_2 sequestered can be created;
- Regulatory issues including the verification and validation of the CO_2 credit (this would necessitate some form of CO_2 monitoring), land ownership, safety and health issues; and
- Financing sources.

10.2 CO_2 Supply

For the micro-pilot test, the CO_2 requirement is relatively small (about 200 tonnes, injected over a period of a week into one well). This volume of CO_2 can be handled with liquid CO_2, trucked in by tankers. For the Australian site in south Bowen Basin, this should not be a problem, as merchant CO_2 and access road would be available to the site. Similarly for China, liquid CO_2 and pumping equipment are available for delivery to the Chinese site in south Qinshui Basin.

For the second stage 5-spot testing, the CO_2 requirement is much larger, about 15,000 tonnes of CO_2 injected over a period of six months (i.e. 100 tCO_2/day). The injection gas can be generated with the exhaust from a gas engine, and supplemented with liquid CO_2. Currently, there is no commercial equipment that can generate a variable composition (CO_2/N_2) "flue gas" for injection. However, a system used in the oil field sector for under-balanced drilling can be readily modified to suit this purpose. The ARC is working on developing such a system for the field test in Alberta, Canada.

The third stage requires a much larger quantity of CO_2. At the commercial demonstration scale, the proposed 41-well scheme will be injecting approximately 400 tCO_2/day. This volume is only feasible with delivery from large CO_2 sources, for example, a coal-fired power plant. This third stage has the biggest uncertainty regarding a secured CO_2 supply for the pilot testing.

CO_2 supplies from power plant flue gas are expensive. Capturing CO_2 from combustion flue gas is more difficult since the CO_2 concentration is low, compared to other sources, for example, gas processing plants and hydrogen plants. CO_2 concentration in the flue gas is 3% from a gas turbine and 13% from a coal-fired power plant. A number of technologies are being developed to capture CO_2 from flue gas, including chemical absorption, physical adsorption, membrane separation, membrane absorption, cryogenic separation and hydrate separation. All are at various stage of development (Wong et al., 1999). To date, all commercial CO_2 capture plants use processes based on chemical absorption with a monoethanolamine (MEA) solution. With current commercial MEA technology such as the Fluor Daniel Econamine FG, CO_2 capture from flue gas is expensive and costs would range from $US 2 to 3/Mcf ($ US 38 to 57/t) of CO_2, from a 13% CO_2 flue gas (coal-fired power plant) to a 3% CO_2 flue gas (gas turbine). With further development of solvent technology and better process integration, researchers suggest that a $US 1/Mcf ($ US 19/t) level for CO_2 may be achievable (Wong et al., 2000). Moreover, technologies that are not solvent based are also being developed and show great promise. One of these technologies is O_2/CO_2 recycle combustion – instead of air, the power plant is fed oxygen produced by an air separation plant (Croiset et al., 1998). The flue gas is re-circulated back to the furnace to moderate the flame temperature. In this process, a high purity CO_2 flue gas can be generated.

In summary, the CO_2 supply for the micro-pilot test is not a concern. For the second stage of 5-spot testing, equipment is being developed for field CO_2 (flue gas) generation and would be available in the timeframe when the project proceeds to that stage. However, for the third stage of commercial demonstration CO_2 supply is less certain. From a strategic point of view, initial discussion with operators with large CO_2 sources, for example, Gladstone power plant or other gas processing plants in the vicinity of Dawson River site should be started, as this kind of negotiation takes long time. On the other front, discussion should be held with the Australian Government as to the possibility and timing of CO_2 emissions credit trading. Without any CO_2 credits, the power plant would not commit to any CO_2 capturing scheme.

10.3 Government Policy on CO_2 Emissions Trading

Australia is a signatory country to the Kyoto Protocol. Even trying to achieve the generous greenhouse gas emission target of 10% above the 1990 level by 2008- 2012, it is still a challenge for Australia. Like other industrialized nations, Australia is also considering some form of CO_2 trading or credit scheme.

Tradeable permits have promise as a major component of an overall policy approach design to meet a Kyoto target commitment involving substantial emission reductions in a cost effective way. This economic instrument when implemented will start to send out a price signal for greenhouse gases (GHGs) indicating that they are no longer "free" in the hopes that this will result in changes in production methods and in consumption patterns to reduce emissions. In the long run, this will mean reduced reliance on fossil fuels and increased contributions by renewable energy sources. This is generally consistent with the Australian Government GHG initiative. A number of key issues must be addressed, for example, the "sector coverage" question and the "who pay" question. More analytical works are needed to address the detailed design issues. The domestic tradeable permit system would fit well with other international trading options allowed under the Kyoto Protocol. This option would probably receive serious consideration in the period leading to the ratification period around 2002.

Currently, Norway is the only country to directly tax CO_2 emissions and to allow operators to avoid taxes by sequestering CO_2. However, even Norway has not allowed a "free" choice of selecting the most efficient scheme, whereby the CO_2 emitter can pay for its choice of the lowest cost emission reduction or sequestration option, including oversea activities.

Recently, great strides have been made in Australia. The Australian Government has set up an Australian Greenhouse Office, which has called for further discussions on carbon credit. The Sydney Futures Exchange has proposed a credit-trading scheme, similar to the one in the US, at the Exchange, which will be implemented later this year. In addition, intra-company CO_2- emission trading systems, such as those recently established by Shell and BP Amoco are setting the precedent for a large-scale global CO_2 emission trading system.

A proposed strategy is to ask the Australian Greenhouse Office to be involved at the very beginning so as to obtain Government buy-in. The CO_2-ECBM process would be a nice fit for a tradeable CO_2 permit system.

China is the second largest source of CO_2 emissions in the world. Because China is so important to the global environment, the rest of the world has an incentive to help and support China through this transition. This means giving China access to international markets, technologies and expertise. Demonstrating the CO_2-ECBM technology in China would fit in nicely in this scenario. China also has a direct interest in avoiding climate change because its impacts could be felt keenly in China.

In May 1998, China became the 37th country to sign the Kyoto Protocol on Climate Change. Its signatory means that if the Protocol is ratified by 55 countries representing 55% of global GHG emissions, China would have to set voluntary targets. This signals China's willingness to be involved, as a global partner, in activities that would reduce GHG emissions and global climate change. This is consistent with the theme of sustainable development set out in China's 10th Five-year Plan. The Plan would place emphasis on the use of market instruments and incentives to foster environmental protection and sustainable development. China is keen on the prospects for clean development mechanisms in accelerating environmental sound technology and attracting foreign investment in China. The CO_2-ECBM project would fit well as it can potentially be developed as a clean development mechanism project and is suitable for CO_2 emission trading with the industrialized countries. More importantly, the CO_2-ECBM project can provide a new source of clean energy, (namely, coalbed methane gas that China badly needs) and the environmental benefits derived from burning methane rather than coal. The areas surrounding the city of Taiyuan, Shanxi Province where the proposed site is located is one of the worst air polluted areas in China.

10.4 Regulatory Issues

Coal Mining versus Coalbed Methane Development

In Queensland, Australia, the Mining Act relates to coal resources to 300 meters depth; below that the Petroleum Act covers the exploitation of coalbed methane. Because most Queensland coal is exploited by an open cut method, this has caused little conflict to date. But in the longer term, most new development of coal will be from underground, and this could be a problem because most of the coal measures are covered by overlapping coal and petroleum tenures. The Queensland Department of Mines and Energy is seeking to resolve this and has produced a Government Green Paper, which has apparently received a generally positive response from the interested parties. Nevertheless, there is some way to go on this.

In the Bowen Basin, the depth foreseen for future mining is to 400 meters. The political climate in Queensland is also swinging in favor of gas utilization rather than coal. Under the recently announced Cleaner Energy Strategy, the Queensland Government will consider measures including requiring electricity retailers to source a proportion of their power from gas and renewable energy, and bringing proposed projects' greenhouse gas emissions under the scrutiny of the State's environmental assessment process.

In New South Wales, coal is mined to 600 meters, but this is partly to obtain high-grade metallurgical coal. Therefore, it may alleviate any problem in Queensland and new South Wales if the coalbed depth is > 650 meters. However, CO_2 is considered a very serious hazard in underground coal mines and in Australia, any proposal into inject CO_2 into coal is likely to meet with opposition from the large and influential coal industry. To avoid the pit fall, projects sites should be far away from mine areas, preferably in separate basins or blocks.

In the south Qinshui Basin, currently there are little coal mining activities in the area. The target coal seams in the pilot site are generally considered too deep to be mineable. So it has not been presented as a potential issue. However, policy needs to be developed to set out a clear guideline on the mineable limit to avoid any future problems of coal mining versus coalbed methane development.

Safety and Health Issues

The risks associated with the transport and injection of CO_2 are reasonably understood in North America, Europe and Australia. There is the remote possibility that CO_2 disposed of in the coalbeds could leak, either through an unidentified migration pathway or as a result of a well failure. The kind of threat that this represents may be judged compared with naturally occurring volcanic CO_2 eruptions. Diffuse CO_2 emissions through the soil or via carbonated springs in volcanic areas do not appear to represent a threat as long as the CO_2 is able to disperse into the atmosphere. However, when CO_2 is able to build up in enclosed spaces, it poses a definite threat (Holloway, 1997).

Risk of CBM gas leakage

Natural methane seeps are known throughout the world. Some leakage may occur through exploitation of CBM reservoirs but it is not expected to be any more than that associated with conventional natural gas reservoirs. Leakage can be minimized by good drilling and production practices. In fact the extraction of CBM for commercial use lowers the pressure and the amount of methane in the reservoir and therefore lowers the possibility of uncontrolled leakage to the surface.

Carbon dioxide is not a hazardous substance, unless there is a rapid eruption and release of the CO_2. Monitoring the CO_2 at the site is essential to preclude accidents and to convince regulatory authorities and parties with a commercial interest that sequestration is real and permanent. Some CBM fields have high CO_2 levels (part of San Juan Basin and Gunnedah Basin). The Fruitland coal in the San Juan Basin contains 8 – 12% natural CO_2. During production, these gases are vented and contributed to greenhouse gas emissions. In the future, operators may find it necessary or desirable to dispose of their CO_2. Sequestration by capture and re-injection is obviously an option.

With respect to flue gas injection into coal, the presence of oxygen is an issue that has not been considered. Power plant flue gas typically contains 3% to 6% oxygen. If an amine process is selected for the CO_2 capture, the oxygen will likely be removed before the amine contractor to avoid the early deteriation and contamination of the amine solution. In addition, oxygen in coal can produce carbon monoxide. In the worst case scenario, it could result in spontaneous combustion. However, at this time it is not clear what factors determine the maximum limit of the oxygen level in the injected gas, as there is limited field experience.

Fugitive methane emission during the production of coalbed methane, in our view, is not substantially different from conventional gas production. Current best practice in oil field production should be sufficient for monitoring its release.

Risk of CBM Water Leakage and Water Quality

Water leakage during exploitation of CBM reservoirs is possible. If the coal horizon is an active aquifer, there is concern that the depressurization of the reservoir may lead to inflow from other aquifers or surface water bodies (e.g. rivers). Consequently, hydrologic data should be collected and evaluated to assess the local impact on regional groundwater flows early in the planning stage.

In the deeper coals, management of the produced water may be critical to the project because of the potentially high dissolved solids content of the water. Such nonpotable water should be injected into deep water disposal wells. Normally leakage of these waters into shallow groundwater is not a concern providing the production wells have good cement bonds above the coal.

The water quality from CBM can often be potable from the shallower coal reservoirs. In the Powder River Coal Basin in Wyoming, USA, the coal beds are active aquifers and the water from them in most cases meets the Wyoming water quality rules and Safe Drinking Water Act levels. Consequently, there is minimal contamination of other groundwater, and surface discharge of this coal bed water is a common practice. However, continuous withdrawal of this water from the coal beds may result in significant depletion of future groundwater resources.

CO_2 Monitoring Issues

If the company has claimed an emission reduction credit associated with a CO_2 disposal scheme, there would likely be ongoing monitoring and verification requirements by the government granting formal "credit recognition" to demonstrate that the CO_2 was in fact not leaking back into the atmosphere. If the emission reduction credit were sold to another company, the buyer would almost certainly also insist on this ongoing monitoring as a part of the commercial contract and appropriate contract clauses would be inserted. While a geologic reservoir or lease may revert back to government upon abandonment, the ownership of any associated CO_2 credits or emission reduction credits becomes a separate matter. Legally speaking, the registered owner of any carbon credit would also be liable for any leakage, but would also be entitled to any financial benefits that may accrue from ownership.

Leakage of CO_2 can occur in two ways. First, CO_2 could leak from the coalbeds through or around a CO_2 injection well. Modern petroleum well completion practices typically include pressure testing of steel tubulars and cement within the well to check for leakage. If identified, leakages are then squeezed off using zone isolation packers and cements. Such operations are routinely performed primarily for economic efficiency of petroleum production rather than safety.

Second, more diffuse and gradual emission of CO_2 could occur by mitigation along stratigraphic bedding or fault planes within the coalbed reservoirs, and dissolve in overlying aquifers producing a carbonate water which may be trapped permanently by water-rock reaction or be released at the surface controlled by the regional aquifer flow rates. If the CO_2 is not trapped by an overlying aquifer, it could be released slowly to the surface as a gas where it could pool in low areas until dispersed by the wind or the heat of the sun. It is extremely unlikely that CO_2 sequestration would lead to a sudden emission of dangerous ground-hugging plumes of CO_2 unless the CO_2 is stored in an active tectonic zone (Hitchon et al., 1999).

In order to guard against environmental hazards occurring, suitable methods to monitor the movement of the stored CO_2 need to be installed (Gunter et al., 1999). Specifically, monitoring of (1) CO_2 injection, (2) migration of CO_2 bubble from tip of the well through the reservoir, (3) CO_2 bubble dissipation by solution in formation water, (4) CO_2-charged-water-rock reaction leading to permanent trapping of CO_2, (5) CO_2 leakage (unplanned as in old wells and through cap rock). Methods to be considered include flow gauges - for CO_2 injection over the short term (i.e. 10's of years); observation wells, fluid tracers, logs, drill stem tests, seismic, electromagnetic, gravimetric and tilt - for migration and dissipation of bubble and trapping of CO_2 over the intermediate and long terms (i.e. 100's to 1,000's of years); flow gauges, separators and gas chromotography at surface - for CO_2 leakage in the short term and diffuse measurements (airborne methods for large areas and laser ground methods for smaller areas) for the long term (after abandonment). To detect subsurface leakage through caprock, drill stem tests are needed.

10.5 Financing of CO_2-ECBM Demonstration Project

The three stages of the demonstration project require financing from $ US 0.67- 0.73 million, $US 6.2 – 6.7 million and $ US 35 - 40 million, respectively. The China demonstration pilot costs are about 10% higher than the Australian costs. While a wide range of instruments can be used to finance the demonstration project, the three categories that characterize the majority of funding sources are:

- Equity – High risk financing that expects high returns. They are the shareholders of the project. Equity investors are expected to exercise their right to get involved in the decision making process of the project to protect their investment.
- Debt – Medium risk with medium expected returns. Lenders provide capital for the purpose of earning interest. Because lenders must be repaid first before distributions can be made to the shareholders, they bear less risk.
- Grant – No expected returns. Government and international organizations offer grants to promote environmental and development polices. The CO_2-ECBM demonstration project may be eligible for these funds.

10.5.1 Sources of Equity Financing

Sources of equity financing include project developers, venture capitalists, equity fund investors, equipment suppliers, multilateral development banks, and institutional and individual investors.

- Project developer – The project developer is likely the owner of the CBM lease where the demonstration pilot and the subsequent commercial project will be located. The developer usually invests "up-front capital" in the beginning to develop the project to a stage that it can be financed.
- Venture capitalists – The venture capitalist specializes in investing in new ventures. Because they join in their earliest and riskiest stage, they expect to earn unusually high returns.
- Equity fund investors – Equity investors provide investment capital to the project in return for a share of the revenues from the project.
- Equipment suppliers – Reliable, experienced equipment supplier companies offer construction, installation and operation of the necessary equipment, but can also offer equipment financing. In addition to turnkey system delivery and operation, the equipment vendor may offer favorable financing terms.
- Regional Development Banks – These are the regional development banks like the Asian development Bank (ADB), Inter-American Development Bank (IDB) and International Finance Corporation (IFC). These Institutions can provide debt financing through certain mechanisms and can also provide minority equity financing through special private sector serving arms such as the IFC. The IFC is one of the World Bank Institutions.

10.5.2 Sources of Debt Financing

A principal source of debt financing is international and national commercial banks. For example, the International bank for Reconstruction and Development (IBRD) provides loans at near-market interest rate to the government of developing countries and economies in transition. IBRD has provided loans to Poland and India. Other sources of debt financing include multilateral development banks and their private sector arms, international and national commercial banks, debt/equity investment funds, equipment suppliers and private investors.

Subordinated debt is another form of financing that falls between debt and equity. Principally, subordinated debt is provided by a "friendly investor" of project partner and is subordinated to other primary debt in case of project default. In return, subordinated debt usually commands a higher interest rate than normal debt to reflect the higher risk associated with the investment.

10.5.3 Sources of Grant Funding

Sources of grant funding include the World Bank's Global Environment Facility, International and Bilateral Agencies, National and local Agencies.

- Global Environment Facility (GEF) – GEF provides financing for activities to protect the global environment in developing countries and economies in transition, and is implemented by the United Nations Development Program (UNDP), the United Nations Environmental Program (UNEP) and the World Bank. GEF provide grants to support the incremental cost of projects that provide benefits to the global environment such as reductions in greenhouse gas emissions, gas emissions, over the costs of "business as usual" projects. The World Bank manages the GEF funds and develops investment operations. Recently, India has obtained GEF funding for its coal seam gas project.
- International and Bilateral Development Agencies – Many international funding agencies such as the United Nations Development Programme (UNDP), the US Agency for International Development (USAID), the Netherlands Ministry of Development Cooperation (DGIS), the Canadian International Development Agency (CIDA) can and do provide grant assistance for worthy environmental projects. UNDP has funded a project "Coalbed Methane Resources Development in China" and ADB also funded a technical assistance project "Study of Coalbed Methane Production in China" with the British Geological Survey and Dutch Gastec NV.
- National and local Agencies – In a number of countries, support for projects is also available from national and local agencies. In China, for example, the Government has provided significant support for developing the coalbed methane industry by funding research and projects to demonstrate coal-mine methane technological applicability to Chinese coals (Schultz, 1999).

10.6 Conclusion

With China being a developing country, the demonstration pilot would likely be developed as a technology transfer project in the beginning with the potential of developing it into a clean development mechanism project or commercial venture in the longer term. The recipient of the technology in the host country would be represented by the state owned company, which for the case of China would be China United Coalbed Methane Co. Ltd. (CUCBM). CUCBM is charged by the State Council for all exploration, development, production and sales of coalbed methane in China. As often the case, the state owned company would not have any hard currency to contribute, but is expected to provide in kind services such as obtaining permit approval, geological assessment, field manpower, well services and local supplies. For stage 1 and perhaps stage 2 of the demonstration pilot, the hard currency financing could come from International Development Agencies such as the World Bank Global Environmental Facility, UNDP, Regional Bank such as ADB or Bilateral Granting Agencies such as USAID for the case of the US and CIDA for the case of Canada. To get approval for International or Bilateral Grants, blessings from the Government such as the State Council and the Ministry of Foreign Trade and Economic Co-operation (MOFTEC) are essential. When the project goes to Stage 3 - commercial demonstration, either CUCBM can provide the financial resources or other international oil and gas companies can be brought in to provide financing to earn a share of the commercial revenues. This process is quite typical of financing project in a developing country.

Obviously, since Australia is an advanced industrialized nation, some of grant funding and loan sources such as World Bank's GEF, IFC or Bilateral Development Agencies such as USAID, CIDA, which would normally be available to developing countries, would not be available to Australia. We expect that private and Australia Government funding will probably be the route. Fortunately, since the pilot demonstration project is developed in stages. It could afford us the time to develop these funding sources gradually. Initially, we envision that Stage 1 of the demonstration project will be funded mostly with Government grant funding supplemented with some industrial funding. Gradually, as the project proceeds through the stages, major energy companies such as Oil Company of Australia or BHP Petroleum Pty. who would benefit most from the commercialization of the process will emerge as the "Champion" and take an increasing share of project financing.

This report outlines the design and costs of demonstration pilot at two potential sites, one in a developed country (Australia) and one in a developing country (China). We believe that these two-country perspectives would compliment one another and facilitate the demonstration of the CO_2-ECBM technology and bring it to a wider spread in the commercialization process.

10.7 References

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ENHANCED RECOVERY OF COAL BED METHANE WITH CARBON DIOXIDE SEQUESTRATION – SELECTION OF POSSIBLE DEMONSTRATION SITES - APPENDICES

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APPENDIX I: SCORING SHEETS FOR SITE EVALUATION OF CO_2 – ECBM

Australia - Southern Bowen Basin, Dawson River

1. Market Potential

Score 0.62

	3	**2**	**1**		**Comments**	**Rating**
Pipeline access / to major load centers	0-100 km	100-500	> 500 km		well served by pipeline, extension planned	3
Gas demand	high	medium	low		higher gas growth in NSW and Queensland	2
Envir. pollution	high	medium	low			1
	4	**2**	**0**			
Wellhead gas price US $ / MCF	$ 2 - 4	$ 1 - 2	< $ 1			2
Total				13		8

2. Production Potential

Score 0.60

	3	**2**	**1**		**Comments**	**Rating**
					< 1 md, score = 0	
Permeability	> 20 md	5-20 md	1-5 md		2-19 md, mean ~ 5md	2
	2	**1**				
Sweep	homo-genous	inhomo-genous			some evidence of compartments, comprehensive data not available	1
Total				5		3

3. Resource/Storage Potential

Score 0.875

	4	**3**	**2**	**1**	**Comments**	**Rating**
Site gas potential BCF/mi2	> 20	10 - 20	3 - 10	< 3	58 billion m3 over 242 km2, 22 BCF/mi2	4
	2	**1**				
CO2 Storage capacity isotherm	10 for 1	2 for 1			high volatile bituminous	1
	2	**1**				
Geology faulting, folding	Simple	Complex			extensive data base	2
Total				8		7

4. CO2 Supply Potential

Score 0.71

	3	2	1		Comments	Rating
Distance to site	< 50 km	50-200km	> 200 km		Gladstone power plant 150 km	2
	2	**1**				
Quality of CO2	Pure	Flue Gas				1
	2	**1**				
Size of CO2 supply	> 4000 t/d	< 4000 t/d				2
Total			7			5

5. Site Infrastructure Costs

Score 0.86

	3	2	1		Comments	Rating
Regulatory regime	Excellent	Fair	Poor			3
	4	**3**	**2**	**1**		
Cost level above reference	0-25%	25-40%	40-100%	> 100%	good infrastructure for CBM drilling and stimulation	3
Total			7			6

Site Score: 198

Drilling Density	Uncertainty Factor	Comments	Rating
			1
1 - 3 wells	0.5	34 CBM wells drilled, number of these stimulated and production tested	
4 - 10 wells	0.7		
11 - 20 wells	0.9		
> 20 wells	1.0		

Adjusted Site Score: 198

Australia - Southern Bowen Basin, Moura

1. Market Potential

Score 0.62

	3	**2**	**1**		**Comments**	**Rating**
Pipeline access / to major load centers	0-100 km	100-500	> 500 km		well served by pipeline, extension planned	3
Gas demand	high	medium	low		higher gas growth in NSW and Queensland	2
Envir. pollution	high	medium	low			1
	4	**2**	**0**			
Wellhead gas price US $ / MCF	$ 2 - 4	$ 1 - 2	< $ 1			2
Total				13		8

2. Production Potential

Score 0.40

	3	**2**	**1**		**Comments**	**Rating**
					< 1 md, score = 0	
Permeability	> 20 md	5-20 md	1-5 md		1-3 md	1
	2	**1**				
Sweep	homo-genous	inhomo-genous			no information for assessment	1
Total				5		2

3. Resource/Storage Potential

Score 0.75

	4	**3**	**2**	**1**	**Comments**	**Rating**
Site gas potential BCF/mi2	> 20	10 - 20	3 - 10	< 3	180 Million m3/km2	3
	2	**1**				
CO2 Storage capacity isotherm	10 for 1	2 for 1			high-medium volatile bituminous	1
	2	**1**				
Geology faulting, folding	Simple	Complex			extensive data base	2
Total			8			6

4. CO2 Supply Potential

Score 0.71

	3	2	1		Comments	Rating
Distance to site	< 50 km	50-200km	> 200 km		Gladstone power plant 150 km	2
	2	**1**				
Quality of CO2	Pure	Flue Gas				1
	2	**1**				
Size of CO2 supply	> 4000 t/d	< 4000 t/d				2
Total			7			5

5. Site Infrastructure Costs

Score 0.86

	3	2	1		Comments	Rating
Regulatory regime	Excellent	Fair	Poor			3
	4	**3**	**2**	**1**		
Cost level above reference	0-25%	25-40%	40-100%	> 100%	good infrastructure for CBM drilling and stimulation	3
Total			7			6

Site Score: 113

Drilling Density	Uncertainty Factor	Comments	Rating
			1
1 - 3 wells	0.5	27 wells drilled	
4 - 10 wells	0.7		
11 - 20 wells	0.9		
> 20 wells	1.0		

Adjusted Site Score: 113

Australia - Southern Bowen Basin, Fairview

1. Market Potential

Score 0.62

	3	**2**	**1**		**Comments**	**Rating**
Pipeline access / to major load centers	0-100 km	100-500	> 500 km		well served by pipeline, extension planned	3
Gas demand	high	medium	low		higher gas growth in NSW and Queensland	2
Envir. pollution	high	medium	low			1
	4	**2**	**0**			
Wellhead gas price US $ / MCF	$ 2 - 4	$ 1 - 2	< $ 1			2
Total				13		8

2. Production Potential

Score 0.40

	3	**2**	**1**		**Comments**	**Rating**
					< 1 md, score = 0	
Permeability	> 20 md	5-20 md	1-5 md		large implied from production testing of cavity completed wells	1
	2	**1**				
Sweep	homo-genous	inhomo-genous			no information for assessment	1
Total				5		2

3. Resource/Storage Potential

Score 0.625

	4	**3**	**2**	**1**	**Comments**	**Rating**
Site gas potential BCF/mi2	> 20	10 - 20	3 - 10	< 3	65 billion m3 over 693 km2, 94 million m3/km2 (9 BCF/mi2)	2
	2	**1**				
CO2 Storage capacity isotherm	10 for 1	2 for 1			high-medium volatile bituminous	1
	2	**1**				
Geology faulting, folding	Simple	Complex			extensive data base	2
Total			8			5

4. CO2 Supply Potential

Score 0.57

	3	**2**	**1**		**Comments**	**Rating**
Distance to site	< 50 km	50-200km	> 200 km		Gladstone power plant 300 km	1
	2	**1**				
Quality of CO2	Pure	Flue Gas				1
	2	**1**				
Size of CO2 supply	> 4000 t/d	< 4000 t/d				2
Total			7			4

5. Site Infrastructure Costs

Score 0.86

	3	**2**	**1**		**Comments**	**Rating**
Regulatory regime	Excellent	Fair	Poor			3
	4	**3**	**2**	**1**		
Cost level above reference	0-25%	25-40%	40-100%	> 100%	good infrastructure for CBM drilling and stimulation	3
Total			7			6

Site Score: 75

Drilling Density	**Uncertainty Factor**	**Comments**	**Rating**
			1
1 - 3 wells	0.5	22 well drilled	
4 - 10 wells	0.7		
11 - 20 wells	0.9		
> 20 wells	1.0		

Adjusted Site Score: 75

Australia - Southern Bowen Basin, Durham Ranch

1. Market Potential

Score 0.62

	3	2	1	Comments	Rating
Pipeline access / to major load centers	0-100 km	100-500	> 500 km	well served by pipeline, extension planned	3
Gas demand	high	medium	low	higher gas growth in NSW and Queensland	2
Envir. pollution	high	medium	low		1
	4	**2**	**0**		
Wellhead gas price US $ / MCF	$ 2 - 4	$ 1 - 2	< $ 1		2
Total			13		8

2. Production Potential

Score 0.40

	3	2	1	Comments	Rating
				< 1 md, score = 0	
Permeability	> 20 md	5-20 md	1-5 md	implied high	1
	2	**1**			
Sweep	homo-genous	inhomo-genous		unable to assess	1
Total			5		2

3. Resource/Storage Potential

Score 0.625

	4	3	2	1	Comments	Rating
Site gas potential BCF/mi2	> 20	10 - 20	3 - 10	< 3	65 billion m3 over 691 km2, 92 million m3/km2 (9 BCF/mi2)	2
	2	**1**				
CO2 Storage capacity isotherm	10 for 1	2 for 1			high-medium volatile bituminous	1
	2	**1**				
Geology faulting, folding	Simple	Complex			limited seismic and geophysical well logging	2
Total			8			5

4. CO2 Supply Potential

Score 0.57

	3	2	1		Comments	Rating
Distance to site	< 50 km	50-200km	> 200 km		Gladstone power plant 350 km	1
	2	**1**				
Quality of CO2	Pure	Flue Gas				1
	2	**1**				
Size of CO2 supply	> 4000 t/d	< 4000 t/d				2
Total			7			4

5. Site Infrastructure Costs

Score 0.86

	3	2	1		Comments	Rating
Regulatory regime	Excellent	Fair	Poor			3
	4	**3**	**2**	**1**		
Cost level above reference	0-25%	25-40%	40-100%	> 100%	good infrastructure for CBM drilling and stimulation	3
Total			7			6

Site Score: 75

Drilling Density	Uncertainty Factor	Comments	Rating
			0.7
1 - 3 wells	0.5	9 CBM appraisal wells drilled	
4 - 10 wells	0.7		
11 - 20 wells	0.9		
> 20 wells	1.0		

Adjusted Site Score: 53

Australia - Southern Sydney Basin, Camden

1. Market Potential

Score 0.62

	3	**2**	**1**	**Comments**	**Rating**
Pipeline access / to major load centers	0-100 km	100-500	> 500 km	well served by pipeline, extension planned	3
Gas demand	high	medium	low	higher gas growth in NSW and Queensland	2
Envir. pollution	high	medium	low		1
	4	**2**	**0**		
Wellhead gas price US $ / MCF	$ 2 - 4	$ 1 - 2	< $ 1		2
Total			13		8

2. Production Potential

Score 0.40

	3	**2**	**1**	**Comments**	**Rating**
				< 1 md, score = 0	
Permeability	> 20 md	5-20 md	1-5 md	variable, 1 md in some areas, 12-36 md reported from some CBM wells	1
	2	**1**			
Sweep	homo-genous	inhomo-genous		no data available, variable between seams	1
Total			5		2

3. Resource/Storage Potential

Score 0.625

	4	**3**	**2**	**1**	**Comments**	**Rating**
Site gas potential BCF/mi2	> 20	10 - 20	3 - 10	< 3	25.5 billion m3 over 275 km2, 92 million m3/km2 (9 BCF/mi2)	2
	2	**1**				
CO2 Storage capacity isotherm	10 for 1	2 for 1			high-medium volatile bituminous	1
	2	**1**				
Geology faulting, folding	Simple	Complex			limited seismic and geophysical well logging	2
Total			8			5

4. CO2 Supply Potential

	3	2	1		Comments	Rating
					Score	0.86
Distance to site	< 50 km	50-200km	> 200 km		main power plants west and north of Sydney basin, 50-100 km	3
	2	**1**				
Quality of CO2	Pure	Flue Gas				1
	2	**1**				
Size of CO2 supply	> 4000 t/d	< 4000 t/d				2
Total			7			6

5. Site Infrastructure Costs

	3	2	1		Comments	Rating
					Score	0.57
Regulatory regime	Excellent	Fair	Poor		competing land use	1
	4	**3**	**2**	**1**		
Cost level above reference	0-25%	25-40%	40-100%	> 100%	good infrastructure for CBM drilling and stimulation	3
Total			7			4

Site Score: 75

Drilling Density	Uncertainty Factor	Comments	Rating
1 - 3 wells	0.5	12 CBM appraisal wells stimulated and completed	0.9
4 - 10 wells	0.7		
11 - 20 wells	0.9		
> 20 wells	1.0		

Adjusted Site Score: 68

Australia - Gunnedah Basin, Narrabri

1. Market Potential

Score 0.62

	3	2	1	Comments	Rating
Pipeline access / to major load centers	0-100 km	100-500	> 500 km	recently constructed to region	3
Gas demand	high	medium	low	higher gas growth in NSW and Queensland	2
Envir. pollution	high	medium	low		1
	4	**2**	**0**		
Wellhead gas price US $ / MCF	$ 2 - 4	$ 1 - 2	< $ 1		2
Total			13		8

2. Production Potential

Score 0.60

	3	2	1	Comments	Rating
				< 1 md, score = 0	
Permeability	> 20 md	5-20 md	1-5 md	18-36 md from well tests	2
	2	**1**			
Sweep	homo-genous	inhomo-genous		no data available	1
Total			5		3

3. Resource/Storage Potential

Score 0.75

	4	3	2	1	Comments	Rating
Site gas potential BCF/mi2	> 20	10 - 20	3 - 10	< 3	130 million m3/km2 (12 BCF/mi2)	3
	2	**1**				
CO2 Storage capacity isotherm	10 for 1	2 for 1			high volatile bituminous	1
	2	**1**				
Geology faulting, folding	Simple	Complex			good definition at margins	2
Total			8			6

4. CO2 Supply Potential

					Score	0.71
	3	**2**	**1**		**Comments**	**Rating**
Distance to site	< 50 km	50-200km	> 200 km		2 coal fired power plants 150 km	2
	2	**1**				
Quality of CO2	Pure	Flue Gas				1
	2	**1**				
Size of CO2 supply	> 4000 t/d	< 4000 t/d				2
Total			7			5

5. Site Infrastructure Costs

					Score	0.86
	3	**2**	**1**		**Comments**	**Rating**
Regulatory regime	Excellent	Fair	Poor			3
	4	**3**	**2**	**1**		
Cost level above reference	0-25%	25-40%	40-100%	> 100%	good infrastructure for CBM drilling and stimulation	3
Total			7			6

Site Score: 170

			Rating
Drilling Density	**Uncertainty Factor**	**Comments**	0.9
1 - 3 wells	0.5	15 CBM wells, 9 stimulated	
4 - 10 wells	0.7		
11 - 20 wells	0.9		
> 20 wells	1.0		

Adjusted Site Score: 153

China - Ordos Basin, Eastern Border

1. Market Potential

Score 0.69

	3	**2**	**1**	**Comments**	**Rating**
Pipeline access / to major load centers	0-100 km	100-500	> 500 km	gas trunk line some 200 km north	2
Gas demand	high	medium	low	no gas infrastructure, not an industrial area	2
Envir. pollution	high	medium	low	env. Issues high on gov't agenda	3
	4	**2**	**0**		
Wellhead gas price US $ / MCF	$ 2 - 4	$ 1 - 2	< $ 1		2
Total			13		9

2. Production Potential

Score 0.60

	3	**2**	**1**	**Comments**	**Rating**
				< 1 md, score = 0	
Permeability	> 20 md	5-20 md	1-5 md	1-40 md - looking for Fairway	2
	2	**1**			
Sweep	homo-genous	inhomo-genous		no assessment	1
Total			5		3

3. Resource/Storage Potential

Score 0.625

	4	**3**	**2**	**1**	**Comments**	**Rating**
Site gas potential BCF/mi2	> 20	10 - 20	3 - 10	< 3	basin average 11 BCF/mi2	3
	2	**1**				
CO2 Storage capacity isotherm	10 for 1	2 for 1			medium volatile bituminous	1
	2	**1**				
Geology faulting, folding	Simple	Complex			complex, with faults and compartmentation	1
Total			8			5

4. CO2 Supply Potential

					Score	0.57
	3	**2**	**1**		**Comments**	**Rating**
Distance to site	< 50 km	50-200km	> 200 km		limited local CO_2 sources	1
	2	**1**				
Quality of CO2	Pure	Flue Gas				1
	2	**1**				
Size of CO2 supply	> 4000 t/d	< 4000 t/d				2
Total			7			4

5. Site Infrastructure Costs

					Score	0.71
	3	**2**	**1**		**Comments**	**Rating**
Regulatory regime	Excellent	Fair	Poor		Gov't has set targets for CBM production	3
	4	**3**	**2**	**1**		
Cost level above reference	0-25%	25-40%	40-100%	> 100%	limited oil and gas industry infrastructure	2
Total			7			5

Site Score: 106

			Rating
Drilling Density	**Uncertainty Factor**	**Comments**	0.9
1 - 3 wells	0.5	ARCO drilled 9 wells on one site,	
4 - 10 wells	0.7	total 15 wells in eastern Ordos	
11 - 20 wells	0.9		
> 20 wells	1.0		

Adjusted Site Score: 95

China - South Qinshui Basin, near CUCBM and CNPC Pilots

1. Market Potential

	3	2	1		Comments	Rating
					Score	0.85
Pipeline access / to major load centers	0-100 km	100-500	> 500 km		access pipeline should be short to reach load centers	3
Gas demand	high	medium	low		one of most industrialized region in China	3
Envir. pollution	high	medium	low		env. Issues high on Gov't agenda	3
	4	**2**	**0**			
Wellhead gas price US $ / MCF	$ 2 - 4	$ 1 - 2	< $ 1			2
Total				13		11

2. Production Potential

	3	2	1		Comments	Rating
					Score	0.40
					< 1 md, score = 0	
Permeability	> 20 md	5-20 md	1-5 md		1-5 md	1
	2	**1**				
Sweep	homo-genous	inhomo-genous			no assessment data	1
Total				5		2

3. Resource/Storage Potential

	4	3	2	1	Comments	Rating
					Score	0.75
Site gas potential BCF/mi2	> 20	10 - 20	3 - 10	< 3	100 billion m3 within 550 km2	3
	2	**1**				
CO2 Storage capacity isotherm	10 for 1	2 for 1			high-medium volatile bituminous	1
	2	**1**				
Geology faulting, folding	Simple	Complex			Simple, thick seam	2
Total			8			6

4. CO2 Supply Potential

Score 0.86

	3	2	1		Comments	Rating
Distance to site	< 50 km	50-200km	> 200 km		Yangcheng and Yaugqual power plants, iron & steel plants & fertilizer plants	3
	2	**1**				
Quality of CO2	Pure	Flue Gas				1
	2	**1**				
Size of CO2 supply	> 4000 t/d	< 4000 t/d				2
Total			7			6

5. Site Infrastructure Costs

Score 0.86

	3	2	1		Comments	Rating
Regulatory regime	Excellent	Fair	Poor		Gov't has set targets for CBM production	3
	4	**3**	**2**	**1**		
Cost level above reference	0-25%	25-40%	40-100%	> 100%	oil and gas industry infrastructure support available	3
Total			7			6

Site Score: 186

Drilling Density	Uncertainty Factor	Comments	Rating
			0.9
1 - 3 wells	0.5	CUCBM has drilled 25 wells in south Qinshui	
4 - 10 wells	0.7		
11 - 20 wells	0.9		
> 20 wells	1.0		

Adjusted Site Score: 168

India - Damodar Jharia Coalfield, Parbatpur Block

1. Market Potential

Score 0.54

	3	**2**	**1**		**Comments**	**Rating**
Pipeline access / to major load centers	0-100 km	100-500	> 500 km		550 km from HBJ National Pipeline	1
Gas demand	high	medium	low		no gas infrastructure	1
Envir. pollution	high	medium	low		significant concern	3
	4	**2**	**0**			
Wellhead gas price US $ / MCF	$ 2 - 4	$ 1 - 2	< $ 1		GAIL controls gas price, US $ 2/MCF range	2
Total				13		7

2. Production Potential

Score 0.60

	3	**2**	**1**		**Comments**	**Rating**
					< 1 md, score = 0	
Permeability	> 20 md	5-20 md	1-5 md		no published data, expect 1-5 md range	1
	2	**1**				
Sweep	homo-genous	inhomo-genous			expect to be good	2
Total				5		3

3. Resource/Storage Potential

Score 0.75

	4	**3**	**2**	**1**	**Comments**	**Rating**
Site gas potential BCF/mi2	> 20	10 - 20	3 - 10	< 3	178 BCF over 20 km2 using 30 m net coal	3
	2	**1**				
CO2 Storage capacity isotherm	10 for 1	2 for 1			2 for 1 high rank bituminous coal	1
	2	**1**				
Geology faulting, folding	Simple	Complex			simple, maybe some compartmentation	2
Total			8			6

4. CO2 Supply Potential

Score 0.86

	3	2	1		Comments	Rating
Distance to site	< 50 km	50-200km	> 200 km		Santaldh & Chandapurs power plants 25 km	3
	2	**1**				
Quality of CO2	Pure	Flue Gas				1
	2	**1**				
Size of CO2 supply	> 4000 t/d	< 4000 t/d				2
Total			7			6

5. Site Infrastructure Costs

Score 0.29

	3	2	1		Comments	Rating
Regulatory regime	Excellent	Fair	Poor		bureaucratic, Coal India may be allow CO2 injection into coal semas	1
	4	**3**	**2**	**1**		
Cost level above reference	0-25%	25-40%	40-100%	> 100%	no oil and gas infrastructure	1
Total			7			2

Site Score: 59

Drilling Density	Uncertainty Factor	Comments	Rating
			0.5
1 - 3 wells	0.5	limited	
4 - 10 wells	0.7	reflect uncertainty in resource estimate	
11 - 20 wells	0.9	and production performance	
> 20 wells	1.0		

Adjusted Site Score: 30

India - Cambay Basin, Gujarat, Mehsana Block

1. Market Potential

	3	2	1		Comments	Rating
					Score	0.69
Pipeline access / to major load centers	0-100 km	100-500	> 500 km		200 km from HBJ National Pipeline	2
Gas demand	high	medium	low		developed gas demand	2
Envir. pollution	high	medium	low		a concern, not as serious as elsewhere	3
	4	**2**	**0**			
Wellhead gas price US $ / MCF	$ 2 - 4	$ 1 - 2	< $ 1		ONGC controls, US $ 2-3 /MCF range, but could change when producers market their gas	2
Total				13		9

2. Production Potential

	3	2	1		Comments	Rating
					Score	0.60
					< 1 md, score = 0	
Permeability	> 20 md	5-20 md	1-5 md		less than 1 to 3 md	1
	2	**1**				
Sweep	homo-genous	inhomo-genous			thick continous coal	2
Total				5		3

3. Resource/Storage Potential

	4	3	2	1	Comments	Rating
					Score	0.75
Site gas potential BCF/mi2	> 20	10 - 20	3 - 10	< 3	2.9 TCF over 400 km2 using 50 m coal	3
	2	**1**				
CO2 Storage capacity isotherm	10 for 1	2 for 1			sub-bituminous	1
	2	**1**				
Geology faulting, folding	Simple	Complex			simple, with minor faulting	2
Total				8		6

4. CO2 Supply Potential

Score 0.86

	3	2	1		Comments	Rating
Distance to site	< 50 km	50-200km	> 200 km		60 km from Gandhinagar power plant	3
	2	**1**				
Quality of CO2	Pure	Flue Gas				1
	2	**1**				
Size of CO2 supply	> 4000 t/d	< 4000 t/d				2
Total			7			6

5. Site Infrastructure Costs

Score 0.43

	3	2	1		Comments	Rating
Regulatory regime	Excellent	Fair	Poor		bureaucratic, block owned by Gujarat Gov't CBM comes under petroleum Ministry	1
	4	**3**	**2**	**1**		
Cost level above reference	0-25%	25-40%	40-100%	> 100%	cost structure not well defined, import tax	2
Total			7			3

Site Score: 114

Drilling Density	Uncertainty Factor	Comments	Rating
			0.5
1 - 3 wells	0.5	3 wells by Essar	
4 - 10 wells	0.7	relected uncertainty in resource estimate	
11 - 20 wells	0.9	and production performance	
> 20 wells	1.0		

Adjusted Site Score: 57

Poland - Upper Silesian basin, Former Amoco Block

1. Market Potential

Score 0.85

	3	2	1	Comments	Rating
Pipeline access / to major load centers	0-100 km	100-500	> 500 km	gas pipeline runs through the area	3
Gas demand	high	medium	low	developing, near ind. complex of Katowice	3
Envir. pollution	high	medium	low	a high concern	3
	4	**2**	**0**		
Wellhead gas price US $ / MCF	$ 2 - 4	$ 1 - 2	< $ 1		2
Total			13		11

2. Production Potential

Score 0.40

	3	2	1	Comments	Rating
				< 1 md, score = 0	
Permeability	> 20 md	5-20 md	1-5 md	no permeability data, expect 1-5 md	1
	2	**1**			
Sweep	homo-genous	inhomo-genous		no information for assessment	1
Total			5		2

3. Resource/Storage Potential

Score 0.5

	4	3	2	1	Comments	Rating
Site gas potential BCF/mi2	> 20	10 - 20	3 - 10	< 3	medium high gas in place, basin average	2
	2	**1**				
CO2 Storage capacity isotherm	10 for 1	2 for 1			high-low volatile bituminous	1
	2	**1**				
Geology faulting, folding	Simple	Complex			densely explored coal basin, structurally complex	1
Total			8			4

4. CO2 Supply Potential

Score 0.86

	3	2	1		Comments	Rating
Distance to site	< 50 km	50-200km	> 200 km		4000 industrial plants in the area	3
	2	**1**				
Quality of CO2	Pure	Flue Gas				1
	2	**1**				
Size of CO2 supply	> 4000 t/d	< 4000 t/d			number of power plants and steelworks	2
Total			7			6

5. Site Infrastructure Costs

Score 0.71

	3	2	1		Comments	Rating
Regulatory regime	Excellent	Fair	Poor		may conflict with mining	2
	4	**3**	**2**	**1**		
Cost level above reference	0-25%	25-40%	40-100%	> 100%	good infrastructure for CBM drilling and stimulation	3
Total			7			5

Site Score: 104

Drilling Density	Uncertainty Factor	Comments	Rating
			0.7
1 - 3 wells	0.5	6 test wells on the site, 30 wells for the basin	
4 - 10 wells	0.7		
11 - 20 wells	0.9		
> 20 wells	1.0		

Adjusted Site Score: 73

APPENDIX II-A. COST ESTIMATES FOR A SINGLE WELL MICRO-PILOT AND FOR A 5-SPOT CO_2 – ECBM DEMONSTRATION PILOT, AUSTRALIA

AUSTRALIA Pilot Plant Costs

Stage 1 Micro-Pilot Testing

	$ A	$ US	Description
Stage 1.1	**$ A**	**$ US**	**Description**
Field Review	50000	30000	Evaluate geology of possible pilot locations,
			obtain quantitative estimates of reservoir properties
Stage 1.2			
Production Well	**$ A**	**$ US**	**Description**
Drilling & Completion Costs			Use Mining rig and drill to a depth of 650 m
Drilling Contract Costs	135425	81255	Rig daily rate $ A 7,000 x 6
			drill 8 1/2" surface hole, drill through coal target
			6 1/8" hole, install tree, incl. rig supervision
Road & Site Preparation	16200	9720	Access & Location Prep., Water Supply, Pre-supervision
Rig transport & Misc. Transport	17000	10200	Rig Mobilization, Rig down move rig
Drilling Fluids	13000	7800	Foam or polymer
Logging (Open Hole)	13260	7956	GR-CNL-LDT-CAL, GR-SP-DLL-MSFL-CAL,
			GR-LSS-waveform, Veloc Survey
Drill Stem Testing, Coring Analysis	7500	4500	core only through seam of interest
Cement & Cementing Services	14950	8970	cement 7" casing, cement 4 1/2" tubing to surface
Casing & Attachments	28875	17325	7" casing, 4 1/2" casing
Other Equipment & Services	1800	1080	Transport/Crane
Land, Engineering, Suprv. & Admin.	18200	10920	Accom. Travel, vehicle hire, fuel/lube, communication
Drilling Subtotal	266210	159726	
Service Rig	3400	2040	mobilize rig, minifrac gear, demob rig (1/5 share)
Survey	15000	9000	Tomographic survey between wells
Trucking & Misc. Transportation			
Logging (Cased Hole) & Perforating	37500	22500	conduct coal breakdown, interference test to injectors,
			perforate producer
Tubing & Attachments	10000	6000	
Pumping Equipment	30000	18000	Beam Pump Unit
Wellhead	8400	5040	Install wellhead and instrumentation
Other Equipment & Services			
Engineering, Supervision & Admin.	8400	5040	Supervision
Completion Subtotal	112700	67620	

Completed Producer Total	378910	227346	
Contingencies @ 15%	56837	34102	
Subtotal	435747	261448	
Formation Evaluation			
On-site & Long-term Desorption Test	45000	27000	
Wireline Services	32000	19200	
Coring Costs	20000	12000	
Contingencies @ 15%	14550	8730	
Subtotal	111550	66930	
GRAND TOTAL STAGE 1.2	547297	328378	
Stage 1.3	**$ A**	**$ US**	**Description**
Stimulation & Treatment	117500	70500	Mobilize mini-frac equip. fracture stimulate producer
Initial Production Test			
Gas Chromatography and Analysis	4000	2400	
Production Test Crew & Equipment	32000	19200	
Supervision	12000	7200	
Subtotal	48000	28800	
Gas Injection			
Carbon Dioxide	50000	30000	
Trucking and Injection	48000	28800	
Pump Pulling	3000	1800	
Supervision	12000	7200	
Subtotal	113000	67800	
Post-Injection Production Testing			
Gas Chromatography and Analysis	6000	3600	
Production Test Crew & Equipment	63000	37800	
Pump Pulling	3000	1800	
Supervision	12000	7200	
Subtotal	84000	50400	
Contingencies @ 15%	54375	32625	
GRAND TOTAL STAGE 1.3	416875	250125	

Stage 1.4	**$ A**	**$ US**	**Description**
Data Analysis & 5-Spot Pilot Design			
Data Analysis & Reporting	35000	21000	
Reservoir Modelling of Field Results	50000	30000	
Project Assessment & Economics	15000	9000	
TOTAL STAGE 1.4	100000	60000	

Summary Stage 1	**$ A**	**$ US**
Stage 1.1	50000	30000
Stage 1.2	547297	328378
Stage 1.3	416875	250125
Stage 1.4	100000	60000
Total	**1114172**	**668503**

Stage 2: 5-Spot Pilot Testing

Injection Well	**$ A**	**$ US**	**Description**
Drilling & Completion Costs			Slim hole injector and drill to a depth of 650 m
Drilling Contract Costs	145250	87150	Rig daily rate $ A 7,000 x 6 drill 6 1/8" thru top coal, HW liner rental, run liner uncemented, run 3 1/2" tubing to surface incl. Supervision
Road & Site Preparation	14200	8520	Access & Location Prep., Water Supply, Pre-supervision
Rig transport & Misc. Transport	17000	10200	Rig Mobilization, Rig down move rig
Drilling Fluids	9100	5460	Foam or polymer
Logging (Open Hole)	13260	7956	GR-CNL-LDT-CAL, GR-SP-DLL-MSFL-CAL, GR-LSS-waveform, Veloc Survey
Drill Stem testing, Coring Analysis	10500	6300	core only through seam of interest
Cement & Cementing Services	4870	2922	cement 3 1/2" tubing to surface, spot sand to avoid damage
Casing & Attachments	28875	17325	
Other Equipment & Services	3300	1980	Transport/Crane, other rental equipment
Land, Engineering, Suprv. & Admin.	15700	9420	Accom. Travel, vehicle hire, fuel/lube, communication
Drilling Subtotal	262055	157233	

Service Rig	3400	2040	mobilize rig, minifrac gear, demob rig (1/5 share)
Survey	15000	9000	Tomographic survey between wells
Trucking & Misc. Transportation	0	0	
Testing	48092	28855	Clean out with service rig, mix clean KCL, displace hole to clean fluid, conduct stress test, conduct perm test, conduct coal breakdown
Wellhead	6000	3600	
Other Equipment & Services	2625	1575	Mobilize test tools
Engineering, Supervision & Admin.	8400	5040	Supervision
Completion Subtotal	83517	50110	
Completed Injector Total	345572	207343	
Contingencies @ 15%	51836	31101	
GRAND TOTAL	397408	238445	

Injection and Production Wells Hookup

	$ A	**$ US**	**Description**
Trench and lay hi-pressure injection & production lines	96580	57948	
Bury injection lines	1600	960	
Foundation slab and prep for comp.	5000	3000	
Install compressor and skid	12500	7500	
Pressure test with water	3000	1800	
Instrumentation package for comp.	60000	36000	
Hookup wellhead and comp. offtake	2400	1440	
Instrumentation install. and check	2000	1200	
Hookup supervision	10000	6000	
Site Cleanup	2400	1440	
Total	195480	117288	
Supply gas engine driven compressor modified with process skid	2700000	1620000	4 million scf/d, 2000 psig

	$ A	$ US	Description
Stage 2.1			
2nd Well Drilling & Completion	547297	328378	Drill and complete production well, including complete formation evaluation
Stage 2.2			
2nd Well N2/CO2 Micro-pilot Testing	416875	250125	Simulate well, perform initial production test, gas injection and post-injection production testing
Stage 2.3			
Conversion of First two Wells to injection Wells	200000	120000	Workover rig mobilization, pull tubing, set injection packer, set injection wellhead, N2 injection test
Stage 2.4			
Production Well Drilling and Completion	630672	378403	Drill, complete and stimulate production well including wireline and coring
Stage 2.5			
Pre-Injection Production	48000	28800	Similar to initial production testing in micro-pilot
Stage 2.6			
Remaining Injection Wells Drilling & Completion	794816	476889	Drill and complete two injection wells, not stimulated
Stage 2.7			
Surface Facility Construction			
Design	100000		
Compressor	2700000		skid mounted
Surface Vessels	200000		
Flue gas/CO2 generator	2000000		skid mounted
Injection and Production Wells Hook-up	195480		
Contingencies @ 15%	779322		
Total	5974802	3584881	
Stage 2.8			
Injection and Production			
Project Manager	175000		

Well Monitoring labor	300000		24 hour manned coverage for 6 months
Well Operating	90000		
Compressor fuels	220000		could be reduced if CBM is used
Produced water disposal	100000		
Provision for make-up CO2	100000		
Contingencies @15%	147750		
Total	1132750	679650	
Stage 2.9			
Final Testing	84000	50400	Similar to post-injection production testing in micro-pilot testing
Stage 2.10			
Analysis and Expansion Design	500000	300000	Design next stage including economic analysis, reservoir modelling and CO2 supplies
STAGE 2 GRAND TOTAL	**10329211**	**6197526**	
less 50% cost recovery of compressor and and flue gas/CO2 generator	2350000	1410000	
STAGE 2 TOTAL (net)	**7979211**	**4787526**	

APPENDIX II-B. CONVENTIONAL CBM, AUSTRALIA

Summary Report
Case: Bowen Basin - Conventional CBM - US$0.55/GJ
(Nominal values)

Net Present Values

Disc Rate (%)	Before Tax Oper Inc. MM$	Before Tax Cap. Inv. MM$	Before Tax Cash Flow MM$	After Tax Cash Flow MM$
0	37	50	-13	-13
6	21	42	-20	-20
8	18	40	-22	-22
10	16	38	-22	-22
12	14	37	-23	-23
14	12	36	-24	-24
Arr:	37	50	-13	-13

Case Description
Bowen Basin, Australia
Enhanced Coalbed Methane Case
Conventional Coalbed Methane Development
100 Producing Well Development
160 Acre Spacing

Global:	Default
Model:	Australia CBM
Currency:	U.S. Dollar
Discount Date:	2000/01
Evaluation Date:	2000/01

Economic Indicators

		B.Tax	A.Tax
ROR	%	0	0
Payout Period	Stnd. (mo's)	0	0
	Proj. (mo's)	0	0
Undisc. PIR	$/ $	-0.27	-0.27
8.0 Pcnt. PIR	$/ $	-0.54	-0.54
12.0 Pcnt. PIR	$/ $	-0.63	-0.63
NPV/Vol @ 8.0	$/E9m3	-4.49	-4.5
NPV/Vol @ 12.0	$/E9m3	-4.81	-4.82
Economic Limit Date		2027/12	

Products Recovery

		Gross	WI
Oil	E6m3	0	0
Gas-Raw	E9m3	5	5
Gas-Sales	E9m3	5	5
Ethane	E6m3	0	0
Propane	E6m3	0	0
Butane	E6m3	0	0
Cond.	E6m3	0	0
Sulphur	E6t	0	0
Other	E9m3	0	0

Company WI

	Initial %	Final %
Working	100	100
Oil	100	100
Gas	100	100
Byprod.	100	100
Other	100	100
Capital	100	100
Royalty	100	100

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Date	Number of Wells	Gas Raw Volume E9m3	Gas Sales Volume E9m3	Water Volume E6m3	Flue Gas Volume E9m3	Gas Price $/GJ	Revenue MM$	Operating Costs MM$	Gas Royalty MM$	Operating Income MM$	Capital MM$	Before Tax Cash Flow MM$	Income Taxes MM$	After Tax Cash Flow MM$
2000(12)	0	0	0	0	0	0.55	0	0	0	0	25	-25	0	-25
2001(12)	50	0	0	0.6	0	0.55	2	1	0	0	0	0	0	0
2002(12)	50	0	0	0.3	0	0.55	3	2	0	1	0	1	0	1
2003(12)	50	0	0	0.1	0	0.55	5	2	0	3	5	-2	0	-2
2004(12)	60	0	0	0.1	0	0.55	5	2	0	3	0	3	0	3
2005(12)	60	0	0	0.1	0	0.55	5	2	0	3	5	-2	0	-2
2006(12)	70	0	0	0.1	0	0.55	5	2	0	3	0	3	0	2
2007(12)	70	0	0	0.1	0	0.55	5	2	0	3	5	-2	0	-2
2008(12)	80	0	0	0.1	0	0.55	5	2	0	2	0	2	0	2
2009(12)	80	0	0	0.1	0	0.55	5	2	0	2	5	-3	0	-3
2010(12)	90	0	0	0.1	0	0.55	5	2	0	2	0	2	0	2
2011(12)	90	0	0	0.1	0	0.55	5	2	0	2	5	-3	0	-3
2012(12)	100	0	0	0.1	0	0.55	5	3	0	2	0	2	0	2
2013(12)	100	0	0	0.1	0	0.55	5	3	0	2	0	2	0	2
2014(12)	100	0	0	0.1	0	0.55	4	2	0	2	0	2	0	2
2015(12)	100	0	0	0.1	0	0.55	4	2	0	2	0	2	0	2
2016(12)	100	0	0	0.1	0	0.55	4	2	0	1	0	1	0	1
2017(12)	100	0	0	0.1	0	0.55	3	2	0	1	0	1	0	1
2018(12)	100	0	0	0.1	0	0.55	3	2	0	1	0	1	0	1
2019(12)	100	0	0	0.1	0	0.55	3	2	0	1	0	1	0	1
Sub.		4	4	2.8	0		81	41	4	36	50	-14	0	-14
Rem.		1	1	0.5	0		13	13	0	1	0	1	0	1
Total		5	5	3.3	0		94	54	4	37	50	-13	0	-13

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APPENDIX II-C. CO_2 – ECBM, AUSTRALIA

Summary Report
Case: Bowen Basin - ECBM (CO2) - US$2.22/GJ
(Nominal values)
Net Present Values

Disc Rate (%)	Before Tax Oper Inc. MM$	Before Tax Cap. Inv. MM$	Before Tax Cash Flow MM$	After Tax Cash Flow MM$
0	458	76	383	236
6	263	63	200	119
8	222	60	162	94
10	189	57	132	74
12	163	55	107	58
14	141	53	87	44
Arr:	458	76	383	236

Bowen Basin, Australi
Enhanced Coalbed Me
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100 Producing Well De
81 CO2 Injection Well

Global:
Model:

Currency:
Discount Date:
Evaluation Date:

Economic Indicators

		B.Tax	A.Tax
ROR	%	36	26.8
Payout Period	Stnd. (mo's)	53.8	66.1
	Proj. (mo's)	66.5	78.6
Undisc. PIR	$/ $	5.05	3.11
8.0 Pcnt. PIR	$/ $	2.71	1.57
12.0 Pcnt. PIR	$/ $	1.95	1.05
NPV/Vol @ 8.0	$/E9m3	21.19	12.27
NPV/Vol @ 12.0	$/E9m3	14.02	7.52
Economic Limit Date		2049/07	

Products Recovery

Oil	E6m3
Gas-Raw	E9m3
Gas-Sales	E9m3
Ethane	E6m3
Propane	E6m3
Butane	E6m3
Cond.	E6m3
Sulphur	E6t
Other	E9m3

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Date	Number of Wells	Gas Raw Volume E9m3	Gas Sales Volume E9m3	Water Volume E6m3	Flue Gas Volume E9m3	Gas Price $/GJ	Revenue MM$	Operating Costs MM$
2000(12)	0	0	0	0	0	2.22	0	0
2001(12)	50	0	0	0.6	0	2.22	6	1
2002(12)	50	0	0	0.3	0	2.22	13	2
2003(12)	50	0	0	0.1	1	2.22	20	2
2004(12)	60	0	0	0.1	1	2.22	31	3
2005(12)	60	1	0	0.1	1	2.22	41	4
2006(12)	70	1	0	0.1	1	2.22	41	4
2007(12)	70	1	0	0.1	1	2.22	41	4
2008(12)	80	1	0	0.1	1	2.22	41	4
2009(12)	80	1	0	0.1	1	2.22	41	4
2010(12)	90	1	0	0.1	1	2.22	41	4
2011(12)	90	1	0	0.1	1	2.22	41	4
2012(12)	100	1	0	0.1	1	2.22	41	4
2013(12)	100	0	0	0.1	1	2.22	37	4
2014(12)	100	0	0	0.1	1	2.22	31	3
2015(12)	100	0	0	0.1	1	2.22	26	3
2016(12)	100	0	0	0.1	1	2.22	22	3
2017(12)	100	0	0	0.1	0	2.22	19	2
2018(12)	100	0	0	0.1	0	2.22	16	2
2019(12)	100	0	0	0.1	0	2.22	13	2

Sub.	7	7	2.8	14	560	57
Rem.	1	1	0.3	1	45	35
Total	8	7	3.2	15	605	92

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Default
Australia CBM

U.S. Dollar
2000/01
2000/01

Gross	WI
0	0
8	8
7	7
0	0
0	0
0	0
0	0
0	0
15	15

Company WI	Initial %	Final %
Working	100	100
Oil	100	100
Gas	100	100
Byprod.	100	100
Other	100	100
Capital	100	100
Royalty	100	100

Gas Royalty MM$	Operating Income MM$	Capital MM$	Before Tax Cash Flow MM$	Income Taxes MM$	After Tax Cash Flow MM$
0	0	36	-36	0	-36
0	4	0	4	1	3
1	10	0	10	3	7
2	16	8	9	5	4
3	25	0	25	8	17
4	33	8	25	11	15
4	33	0	33	11	23
4	33	8	25	11	15
4	33	0	33	11	23
4	33	8	25	10	15
4	33	0	33	10	23
4	33	8	25	10	15
4	33	0	33	10	23
3	30	0	30	9	21
3	25	0	25	7	18
2	21	0	21	6	15
2	18	0	18	5	12
2	15	0	15	4	10
1	12	0	12	4	9
1	10	0	10	3	7

50	453	76	377	138	239
3	6	0	6	9	-3
54	458	76	383	147	236

APPENDIX II-D. FLUE GAS ECBM, AUSTRALIA

Summary Report
Case: Bowen Basin - ECBM (Flue Gas) - US$0.55/GJ
(Nominal values)

Net Present Values

Disc Rate (%)	Before Tax Oper Inc. MM$	Before Tax Cap. Inv. MM$	Before Tax Cash Flow MM$	After Tax Cash Flow MM$
0	81	76	5	-5
6	53	66	-13	-20
8	46	63	-17	-23
10	41	61	-20	-26
12	36	59	-23	-28
14	32	57	-25	-30
Arr:	81	76	5	-5

Case Description
Bowen Basin, Australia
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81 Flue Gas Injection \

Global:
Model:

Currency:
Discount Date:
Evaluation Date:

Economic Indicators

		B.Tax	A.Tax
ROR	%	1.3	0
Payout Period	Stnd. (mo's)	157.1	0
	Proj. (mo's)	157.1	0
Undisc. PIR	$/ $	0.07	-0.07
8.0 Pcnt. PIR	$/ $	-0.27	-0.37
12.0 Pcnt. PIR	$/ $	-0.39	-0.47
NPV/Vol @ 8.0	$/E9m3	-2.25	-3.06
NPV/Vol @ 12.0	$/E9m3	-3	-3.65
Economic Limit Date		2025/12	

Products Recovery

Oil	E6m3
Gas-Raw	E9m3
Gas-Sales	E9m3
Ethane	E6m3
Propane	E6m3
Butane	E6m3
Cond.	E6m3
Sulphur	E6t
Other	E9m3

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Date	Number of Wells	Gas Raw Volume E9m3	Gas Sales Volume E9m3	Water Volume E6m3	Flue Gas Volume E9m3	Gas Price $/GJ	Revenue MM$	Operating Costs MM$
2000(12)	0	0	0	0	0	0.55	0	0
2001(12)	50	0	0	0.6	0	0.55	2	1
2002(12)	50	0	0	0.3	0	0.55	4	2
2003(12)	50	1	1	0.1	1	0.55	11	4
2004(12)	60	1	1	0.1	2	0.55	15	5
2005(12)	70	1	1	0.1	2	0.55	15	5
2006(12)	80	1	1	0.1	2	0.55	15	5
2007(12)	90	1	1	0.1	2	0.55	15	5
2008(12)	100	1	1	0.1	2	0.55	15	5
2009(12)	100	1	1	0.1	1	0.55	14	5
2010(12)	100	1	1	0.1	1	0.55	11	4
2011(12)	100	0	0	0.1	1	0.55	8	3
2012(12)	100	0	0	0.1	1	0.55	7	3
2013(12)	100	0	0	0.1	1	0.55	5	3
2014(12)	100	0	0	0.1	0	0.55	4	2
2015(12)	100	0	0	0.1	0	0.55	3	2

2016(12)	100	0	0	0.1	0	0.55	2	2
2017(12)	100	0	0	0.1	0	0.55	2	2
2018(12)	100	0	0	0.1	0	0.55	2	2
2019(12)	79	0	0	0.1	0	0.55	1	1
Sub.		8	7	2.8	15		151	61
Rem.		0	0	0.3	0		0	0
Total		8	7	3.2	15		151	61

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Wells

Default
Australia CBM

U.S. Dollar
2000/01
2000/01

Gross	WI
0	0
8	8
7	7
0	0
0	0
0	0
0	0
0	0
15	15

Company WI	Initial %	Final %
Working	100	100
Oil	100	100
Gas	100	100
Byprod.	100	100
Other	100	100
Capital	100	100
Royalty	100	100

Gas Royalty MM$	Operating Income MM$	Capital MM$	Before Tax Cash Flow MM$	Income Taxes MM$	After Tax Cash Flow MM$
0	0	36	-36	0	-36
0	0	0	0	0	0
0	2	0	2	0	2
1	7	8	-1	0	-2
1	9	8	1	2	-1
1	9	8	1	2	-1
1	9	8	1	2	0
1	9	8	1	1	0
1	9	0	9	1	8
1	8	0	8	1	7
1	6	0	6	0	6
0	4	0	4	0	4
0	3	0	3	0	3
0	2	0	2	0	2
0	2	0	2	0	2
0	1	0	1	0	1

0	1	0	1	0	1
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
9	81	76	5	10	-5
0	0	0	0	0	0
9	81	76	5	10	-5

APPENDIX III. CHINESE ASSESSMENT OF THE SOUTH QINSHUI BASIN SITE

The following is excerpted from a private communication between China United Coalbed Methane Company (CUCBM) and Alberta Research Council (ARC).

CUCBM believes that Qinshui Basin is more suitable for CO_2 injection than the Ordos Basin.

1) Coal Rank: CUCBM owns an area of over 6,000 sq km with the license to explore for Coalbed Methane (CBM) in the South Qinshui Basin. That the coal rank is relatively high in the South Qinshui Basin is a fact. However, not the whole area has so high coal rank and it varies. The experience of CBM exploration in high coal rank, such as anthracite is limited in other parts of the world. China has accumulated significant experiences in this regard with nearly ten years of exploration practice. It has been proved by the CBM exploration results of Qinshui Basin that commercial CBM production can be attained from high coal-rank coal seams in China. The actual CBM exploration results proved the permeability generally varies from 1 to 5 md in the South Qinshui Basin. Furthermore, the thickness of coal seams in the South Qinshui Basin is very stable, with No. 3 coal seam averaging 6 meters and No. 15 coal seam averaging 4 meters, which is very advantageous in CO_2 injection. At present, the South Qinshui Basin is considered as the most hopeful CBM production base in China.

2) Production Testing: To date, none of CBM fields has entered into commercial development phase in China, but stable gas production was achieved at the test wells of exploration phase in the South Qinshui Basin. For example, the pilot wells in Jincheng area have been producing at a rate of about 4000 m^3 per day per well for seven years and the Contractor of Jincheng project, US Geomer company, is actively requesting early entry into commercial development phase. The reason why those discovery wells, TL-003, TL-006, TL-007, in Tunliu area have stopped producing CBM is because of deficient funds and engineering incidents, and not CBM itself. These great discoveries of industrial CBM production in the South Qinshui Basin have showed the promising potential of CBM development.

3) Lack of Foreign CBM Interest: This is not the case here. In fact, Texaco and Phillips have expressed their strong interest in co-operational exploration of CBM in the South Qinshui Basin long before. Because CUCBM has been considering the South Qinshui Basin as his own self-financed CBM exploration base and hasn’t planned to open it to foreign investors, CUCBM didn’t agree on the requests of Texaco and Phillips. Till recently, CUCBM plans to open the South Qinshui Basin and is negotiating with Phillips concerning the cooperation exploration. CUCBM has never talked about CBM cooperation of Qinshui Basin with BP, Enron, etc.

4) Geologic Interpretation: In total 38 CBM exploratory wells have been drilled in the South Qinshui Basin. At present, some well spacing have been shortened to 200 meters. The conclusion that the South Qinshui Basin has simpler geology and structure than Ordos Basin comes from the detailed and large quantity of exploration results, not from second hand geological interpretation. These are the most active CBM exploration activities in the South Qinshui Basin in China.

5) Gas Content: Gas content varies from 15 to 30 m^3 per ton in the South Qinshui Basin. The sealing conditions of main coal seams are very good.

APPENDIX IV-A. COST ESTIMATES FOR A SINGLE WELL MICRO-PILOT AND FOR A 5-SPOT CO_2 – ECBM DEMONSTRATION PILOT, CHINA.

China Pilot Plant Costs
Stage 1 Micro-Pilot Testing

	$ US	$ Yuan	Description
Stage 1.1	**$ US**	**$ Yuan**	**Description**
Field Review	30000	249000	Evaluate geology of possible pilot locations, obtain quantitative estimates of reservoir properties
Stage 1.2			
Production Well	**$ US**	**$ Yuan**	**Description**
Drilling & Completion Costs			Conventional oilfield drilling
Drilling Contract Costs	80000	664000	drill 12 1/4" surface hole and 9 5/8" surface casing(150 meters) drill through coal target 8 1/2" hole and 5 1/2" casing, install tree
Road & Site Preparation	8200	68060	Access & Location Prep., Water Supply, Pre-supervision
Rig transport & Misc. Transport	18500	153550	Rig Mobilization, Rig Demobilization, RD/RU, move rig(1/5 share)
Drilling Fluids	8000	66400	Water Based Mud
Logging (Open Hole)	15000	124500	DLL, Micro-Resistivity, GR, SP, DEN, CAL, CNL, Temperature Logging
Drill Stem Testing, Coring Analysis	8500	70550	Single coal seam testing, mainly No. 15 coal seam in Qinshui Basin
Cement & Cementing Services	12500	103750	cement 5 1/2" casing to surface
Casing & Attachments	30800	255640	9 5/8" casing, 5 1/2" casing
Other Equipment & Services	2200	18260	Transport/Crane
Land, Engineering, Suprv. & Admin.	22460	186418	Accom. Travel, vehicle hire, fuel/lube, communication
Drilling Subtotal	206160	1711128	
Service Rig	3940	32702	mobilize rig, minifrac gear, demob rig (1/5 share)
Survey	15000	124500	Tomographic survey between wells
Trucking & Misc. Transportation	2000		
Logging (Cased Hole) & Perforating	12160	100928	GR,CBL,CCL,conduct coal breakdown, interference test to injectors, perforate producer
Tubing & Attachments	7680	63744	2 7/8", N-80, 6.5ppf,rod and accessories
Pumping Equipment	18750	155625	Beam Pump Unit(500 BWPD)
Wellhead	4000	33200	Install wellhead and instrumentation
Other Equipment & Services	1000		
Engineering, Supervision & Admin.	4940	41002	Supervision
Completion Subtotal	69470	576601	

Completed Producer Total	275630	2287729	
Contingencies @ 15%	41345	343159	
Subtotal	316975	2630888	
Formation Evaluation			
On-site & Long-term Desorption Test	25000	207500	
Wireline Services	22500	186750	750/m, calculating 30 meters
Coring Costs	15000	124500	Conventional Coring Analysis
Contingencies @ 15%	9375	77813	
Subtotal	71875	596563	
GRAND TOTAL STAGE 1.2	388850	3227451	
Stage 1.3	**$ US**	**$ Yuan**	**Description**
Stimulation & Treatment	90000	747000	Mobilize mini-frac equip. fracture stimulate producer, one interval(1/5 share)
Initial Production Test			
Gas Chromatography and Analysis	2400	19920	
Production Test Crew & Equipment	18000	149400	
Supervision	7500	62250	
Subtotal	27900	231570	
Gas Injection			
Carbon Dioxide	25000	207500	
Trucking and Injection	20000	166000	
Pump Pulling	1800	14940	
Supervision	7500	62250	
Subtotal	54300	450690	
Post-Injection Production Testing			
Gas Chromatography and Analysis	3600	29880	
Production Test Crew & Equipment	35000	290500	
Pump Pulling	1800	14940	
Supervision	7500	62250	
Subtotal	47900	397570	
Contingencies @ 15%	33015	274025	
GRAND TOTAL STAGE 1.3	253115	2100855	

Stage 1.4	$ US	$ Yuan	Description
Data Analysis & 5-Spot Pilot Design			
Data Analysis & Reporting	21000	174300	
Reservoir Modelling of Field Results	30000	249000	
Project Assessment & Economics	9000	74700	
TOTAL STAGE 1.4	60000	498000	

Summary Stage 1	**$ US**	**$ Yuan**
Stage 1.1	30000	249000
Stage 1.2	388850	3227451
Stage 1.3	253115	2100855
Stage 1.4	60000	498000
Total	**731965**	6075305

Stage 2: 5-Spot Pilot Testing

Injection Well	**$ US**	**$ Yuan**	**Description**
Drilling & Completion Costs			Same as production well and drill to a depth of 650 m
Drilling Contract Costs	80000	664000	drill 12 1/4" surface hole and 9 5/8" surface casing(150 meters) drill through coal target 8 1/2" hole and 5 1/2" casing, install tree
Road & Site Preparation	8200	68060	Access & Location Prep., Water Supply, Pre-supervision
Rig transport & Misc. Transport	18500	153550	Rig Mobilization, Rig Demobilization, RD/RU, move rig(1/5 share)
Drilling Fluids	8000	66400	Water Based Mud
Logging (Open Hole)	15000	124500	DLL, Micro-Resistivity, GR, SP, DEN, CAL, CNL, Temperature Logging
Drill Stem testing, Coring Analysis	8500	70550	Single coal seam testing, mainly No. 15 coal seam in Qinshui Basin
Cement & Cementing Services	12500	103750	cement 5 1/2" casing to surface
Casing & Attachments	30800	255640	9 5/8" casing, 5 1/2" casing
Other Equipment & Services	2200	18260	Transport/Crane, other rental equipment
Land, Engineering, Suprv. & Admin.	20460	169818	Accom. Travel, vehicle hire, fuel/lube, communication
Drilling Subtotal	204160	1694528	

Service Rig	3940	32702	mobilize rig, minifrac gear, demob rig (1/5 share)
Survey	15000	124500	Tomographic survey between wells
Trucking & Misc. Transportation	2000	16600	
Logging (Cased Hole) & Perforating	12160	100928	GR,CBL,CCL,conduct coal breakdown, interference test to injectors, perforate producer
Testing	22000	182600	Clean out with service rig, mix clean KCL, displace hole to clean fluid, conduct stress test, conduct perm test, conduct coal breakdown
Tubing & Attachments	6500	53950	2 7/8", N-80, 6.5ppf,packer and accessories
Wellhead	4000	33200	Install wellhead and instrumentation
Other Equipment & Services	2000	16600	Mobilize test tools
Engineering, Supervision & Admin.	4940	41002	
Completion Subtotal	72540	602082	
Completed Injector Total	276700	2296610	
Contingencies @ 15%	41505	344492	
GRAND TOTAL	318205	2641102	

Injection and Production Wells Hookup

	$ US	**$ Yuan**	**Description**
Trench and lay hi-pressure injection & production lines	63743	529067	
Bury injection lines	1056	8765	
Foundation slab and prep for comp.	3300	27390	
Install compressor and skid	8250	68475	
Pressure test with water	1980	16434	
Instrumentation package for comp.	39600	328680	
Hookup wellhead and comp. offtake	1584	13147	
Instrumentation install. and check	1320	10956	
Hookup supervision	6600	54780	
Site Cleanup	1584	13147	
Total	129017	1070841	
Supply gas engine driven compressor modified with process skid	1518000	12599400	4 million scf/d, 2000 psig

	$ US	$ Yuan	Description
Stage 2.1			
2nd Well Drilling & Completion	388850	3227451	Drill and complete production well, including complete formation evaluation
Stage 2.2			
2nd Well N2/CO2 Micro-pilot Testing	253115	2100855	Simulate well, perform initial production test, gas injection and post-injection production testing
Stage 2.3			
Conversion of First two Wells to injection Wells	120000	996000	
Stage 2.4			
Production Well Drilling and Completion	463600	3847876	Drill, complete and stimulate production well including wireline and coring
Stage 2.5			
Pre-Injection Production	27900	231570	Similar to initial production testing in micro-pilot
Stage 2.6			
Remaining Injection Wells Drilling & Completion	636410	5282203	Drill and complete two injection wells, not stimulated
Stage 2.7			
Surface Facility Construction			
Design	50000		
Compressor	1518000		skid mounted
Surface Vessels	120000		
Flue gas/CO2 generator	1500000		skid mounted
Injection and Production Wells Hook-up	129017		
Contingencies @ 15%	497553		
Total	3814570	31660927	
Stage 2.8			

Injection and Production			
Project Manager	100000		
Well Monitoring labor	200000		24 hour manned coverage for 6 months
Well Operating	60000		
Compressor Fuels	130000		could be reduced if CBM is used
Produced Water Disposal	50000		
Provision for make-up CO2	60000		
Contingencies @15%	90000		
Total	690000	5727000	
Stage 2.9			
Final Testing	47900	397570	Similar to post-injection production testing in micro-pilot testing
Stage 2.10			
Analysis and Expansion Design	300000	2490000	Design next stage including economic analysis, reservoir modelling and CO2 supplies
STAGE 2 GRAND TOTAL	**6742344**	**55961451**	
less 50% cost recovery of compressor and and flue gas/CO2 generator	1509000	12524700	
STAGE 2 TOTAL (net)	**5233344**	**43436751**	

Note: $ US 1 = $ 8.3 Yuans

APPENDIX IV-B. CONVENTIONAL CBM, CHINA

Summary Report
Case: Qinshui Basin - Conventional CBM - $2.00

Net Present Values

Disc Rate (%)	Before Tax Oper Inc. M$	Before Tax Cap. Inv. M$	Before Tax Cash Flow M$	After Tax Cash Flow M$
0	261,701	61,500	200,201	134,073
6	141,282	51,479	89,803	56,318
8	118,807	49,120	69,686	42,051
10	101,236	47,109	54,127	30,986
12	87,281	45,385	41,897	22,265
14	76,039	43,899	32,139	15,292
Arr:	261,701	61,500	200,201	134,073

Case Description

Qinshui Basin, China
Conventional Coalbed Methane Case
100 Producing Well Development
160 Acre Spacing

Global:	Default
Model:	China CBM
Currency:	U.S. Dollar
Discount Date:	2000/01
Evaluation Date:	2000/01

Economic Indicators

		B.Tax	A.Tax
ROR	%	26.6	20.7
Payout Period	Stnd. (mo's)	55	68.7
	Proj. (mo's)	75.2	88
Undisc. PIR	$/ $	3.26	2.18
8.0 Pcnt. PIR	$/ $	1.42	0.86
12.0 Pcnt. PIR	$/ $	0.92	0.49
NPV/Vol @ 8.0	$/E6m3	14.55	8.78
NPV/Vol @ 12.0	$/E6m3	8.75	4.65
Economic Limit Date		2027/12	

Products Recovery

		Gross	WI
Oil	E3m3	0	0
Gas-Raw	E6m3	4,790	4,790
Gas-Sales	E6m3	4,550	4,550
Ethane	E3m3	0	0
Propane	E3m3	0	0
Butane	E3m3	0	0
Cond.	E3m3	0	0
Sulphur	E3t	0	0
Other	E6m3	0	0

Company WI

	Initial %	Final %
Working	100	100
Oil	100	100
Gas	100	100
Byprod.	100	100
Other	100	100
Capital	100	100
Royalty	100	100

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Date	Number of Wells	Gas Raw Volume E6m3	Gas Sales Volume E6m3	Water Volume E3m3	Injected Gas Volume E6m3	Gas Price $/GJ	Revenue M$	Operating Costs M$	Gas Royalty M$	Operating Income M$	Capital M$	Before Tax Cash Flow M$	Income Taxes M$	After Tax Cash Flow M$
2000(12)	0	0	0	0	0	1.95	0	0	0	0	30,750	-30,750	0	-30,750
2001(12)	50	77	73	580.3	0	1.95	5,348	1,496	267	3,585	0	3,585	3	3,582
2002(12)	50	167	159	290.2	0	1.95	11,588	1,702	579	9,307	0	9,307	1,734	7,572
2003(12)	50	257	244	145.1	0	1.95	17,827	2,044	891	14,892	6,150	8,742	3,373	5,369
2004(12)	60	258	245	145.1	0	1.95	17,876	2,156	894	14,826	0	14,826	3,371	11,456
2005(12)	60	257	244	145.5	0	1.95	17,827	2,152	891	14,783	6,150	8,633	3,105	5,528
2006(12)	70	257	244	145.1	0	1.95	17,827	2,260	891	14,676	0	14,676	3,070	11,606
2007(12)	70	257	244	145.1	0	1.95	17,827	2,260	891	14,676	6,150	8,526	2,835	5,691
2008(12)	80	258	245	145.1	0	1.95	17,876	2,372	894	14,610	0	14,610	2,796	11,815
2009(12)	80	257	244	145.5	0	1.95	17,827	2,368	891	14,567	6,150	8,417	3,762	4,655
2010(12)	90	257	244	145.1	0	1.95	17,827	2,476	891	14,460	0	14,460	3,757	10,703
2011(12)	90	257	244	145.1	0	1.95	17,827	2,476	891	14,460	6,150	8,310	3,757	4,553
2012(12)	100	258	245	145.1	0	1.95	17,876	2,588	894	14,394	0	14,394	3,735	10,659
2013(12)	100	245	232	145.5	0	1.95	16,962	2,518	848	13,596	0	13,596	3,726	9,870
2014(12)	100	221	210	58	0	1.95	15,321	2,310	766	12,245	0	12,245	3,280	8,965
2015(12)	100	200	190	58	0	1.95	13,839	2,196	692	10,951	0	10,951	3,106	7,844
2016(12)	100	180	171	58	0	1.95	12,500	2,094	625	9,782	0	9,782	2,721	7,061
2017(12)	100	163	155	58.2	0	1.95	11,291	2,001	565	8,726	0	8,726	2,626	6,100
2018(12)	100	147	140	58	0	1.95	10,199	1,917	510	7,772	0	7,772	2,311	5,461
2019(12)	100	133	126	58	0	1.95	9,212	1,841	461	6,910	0	6,910	2,280	4,630
Sub.		4,105	3,900	2,815.80	0		284,680	41,228	14,234	229,219	61,500	167,719	55,347	112,372
Rem.		684	650	464.6	0		47,444	12,590	2,372	32,482	0	32,482	10,781	21,702
Total		4,790	4,550	3,280.40	0		332,125	53,817	16,606	261,701	61,500	200,201	66,128	134,073

Peep

APPENDIX IV-C. CO_2 – ECBM, CHINA

Summary Report
Case: Qinshui Basin - ECBM (CO2) - $0.50

Net Present Values

Disc Rate (%)	Before Tax Oper Inc. M$	Before Tax Cap. Inv. M$	Before Tax Cash Flow M$	After Tax Cash Flow M$
0	33,791	86,735	-52,944	-52,944
6	31,198	72,456	-41,258	-41,258
8	27,429	69,079	-41,650	-41,650
10	23,932	66,194	-42,262	-42,262
12	20,855	63,715	-42,860	-42,860
14	18,209	61,576	-43,367	-43,367
Arr:	33,791	86,735	-52,944	-52,944

Case Description
Qinshui Basin, China
Enhanced Coalbed Methane Case
CO2 Sequestration Project
100 Producing Well Development
81 CO2 Injection Wells

Global:	Default
Model:	China CBM
Currency:	U.S. Dollar
Discount Date:	2000/01
Evaluation Date:	2000/01

Economic Indicators

		B.Tax	A.Tax
ROR	%	>800.0	>800.0
Payout Period	Stnd. (mo's)	0	0
	Proj. (mo's)	0	0
Undisc. PIR	$/ $	-0.61	-0.61
8.0 Pcnt. PIR	$/ $	-0.6	-0.6
12.0 Pcnt. PIR	$/ $	-0.67	-0.67
NPV/Vol @ 8.0	$/E6m3	-5.43	-5.43
NPV/Vol @ 12.0	$/E6m3	-5.59	-5.59
Economic Limit Date		2049/07	

Products Recovery

		Gross	WI
Oil	E3m3	0	0
Gas-Raw	E6m3	7,663	7,663
Gas-Sales	E6m3	7,280	7,280
Ethane	E3m3	0	0
Propane	E3m3	0	0
Butane	E3m3	0	0
Cond.	E3m3	0	0
Sulphur	E3t	0	0
Other	E6m3	15,327	15,327

Company WI

	Initial %	Final %
Working	100	100
Oil	100	100
Gas	100	100
Byprod.	100	100
Other	100	100
Capital	100	100
Royalty	100	100

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Date	Number of Wells	Gas Raw Volume E6m3	Gas Sales Volume E6m3	Water Volume E3m3	Injected Gas Volume E6m3	Gas Price $/GJ	Revenue M$	Operating Costs M$	Gas Royalty M$	Operating Income M$	Capital M$	Before Tax Cash Flow M$	Income Taxes M$	After Tax Cash Flow M$
2000(12)	0	0	0	0	0	0.49	0	0	0	0	42,435	-42,435	0	-42,435
2001(12)	50	77	73	581.9	154	0.49	1,337	1,497	67	-227	0	-227	0	-227
2002(12)	50	167	159	290.2	339	0.49	2,897	1,702	145	1,050	0	1,050	0	1,050
2003(12)	50	257	244	145.1	514	0.49	4,457	2,044	223	2,190	8,430	-6,240	0	-6,240
2004(12)	60	387	367	145.1	773	0.49	6,704	2,842	335	3,527	0	3,527	0	3,527
2005(12)	60	514	488	145.5	1,028	0.49	8,914	3,520	446	4,948	10,580	-5,632	0	-5,632
2006(12)	70	514	488	145.1	1,028	0.49	8,914	3,628	446	4,840	0	4,840	0	4,840
2007(12)	70	514	488	145.1	1,028	0.49	8,914	3,628	446	4,840	8,430	-3,590	0	-3,590
2008(12)	80	516	490	145.1	1,031	0.49	8,938	3,743	447	4,748	0	4,748	0	4,748
2009(12)	80	514	488	145.5	1,028	0.49	8,914	3,736	446	4,732	8,430	-3,698	0	-3,698
2010(12)	90	514	488	145.1	1,028	0.49	8,914	3,844	446	4,624	0	4,624	0	4,624
2011(12)	90	514	488	145.1	1,028	0.49	8,914	3,844	446	4,624	8,430	-3,806	0	-3,806
2012(12)	100	516	490	145.1	1,031	0.49	8,938	3,959	447	4,532	0	4,532	0	4,532
2013(12)	100	473	449	145.5	945	0.49	8,194	3,731	410	4,053	0	4,053	0	4,053
2014(12)	100	398	378	58	796	0.49	6,898	3,251	345	3,301	0	3,301	0	3,301
2015(12)	100	335	318	58	670	0.49	5,806	2,916	290	2,600	0	2,600	0	2,600
2016(12)	100	282	268	58	564	0.49	4,888	2,635	244	2,009	0	2,009	0	2,009
2017(12)	100	237	225	58.2	474	0.49	4,115	2,397	206	1,512	0	1,512	0	1,512
2018(12)	100	200	190	58	399	0.49	3,464	2,197	173	1,093	0	1,093	0	1,093
2019(12)	100	168	160	58	336	0.49	2,916	2,029	146	741	0	741	0	741
Sub.		7,097	6,742	2,817.40	14,197		123,032	57,144	6,152	59,736	86,735	-26,999	0	-26,999
Rem.		566	538	348.5	1,129		9,818	35,272	491	-25,945	0	-25,945	0	-25,945
Total		7,663	7,280	3,165.90	15,327		132,850	92,416	6,642	33,791	86,735	-52,944	0	-52,944

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APPENDIX IV-D. FLUE GAS ECBM, CHINA

Summary Report
Case: Qinshui Basin - ECBM (Flue Gas) - $0.50

Net Present Values

Disc Rate (%)	Before Tax Oper Inc. M$	Before Tax Cap. Inv. M$	Before Tax Cash Flow M$	After Tax Cash Flow M$
0	64,866	86,735	-21,869	-21,869
6	42,669	72,456	-29,787	-29,787
8	37,493	69,079	-31,586	-31,586
10	33,102	66,194	-33,091	-33,091
12	29,358	63,715	-34,357	-34,357
14	26,150	61,576	-35,426	-35,426
Arr:	64,866	86,735	-21,869	-21,869

Case Description
Qinshui Basin, China
Enhanced Coalbed Methane Case
Flue Gas Sequestration Project
100 Producing Well Development
81 Flue Gas Injection Wells

Global:	Default
Model:	China CBM
Currency:	U.S. Dollar
Discount Date:	2000/01
Evaluation Date:	2000/01

Economic Indicators

		B.Tax	A.Tax
ROR	%	0	0
Payout Period	Stnd. (mo's)	0	0
	Proj. (mo's)	0	0
Undisc. PIR	$/ $	-0.25	-0.25
8.0 Pcnt. PIR	$/ $	-0.46	-0.46
12.0 Pcnt. PIR	$/ $	-0.54	-0.54
NPV/Vol @ 8.0	$/E6m3	-4.12	-4.12
NPV/Vol @ 12.0	$/E6m3	-4.48	-4.48
Economic Limit Date		2025/12	

Products Recovery

		Gross	WI
Oil	E3m3	0	0
Gas-Raw	E6m3	7,663	7,663
Gas-Sales	E6m3	7,280	7,280
Ethane	E3m3	0	0
Propane	E3m3	0	0
Butane	E3m3	0	0
Cond.	E3m3	0	0
Sulphur	E3t	0	0
Other	E6m3	15,327	15,327

Company WI

	Initial %	Final %
Working	100	100
Oil	100	100
Gas	100	100
Byprod.	100	100
Other	100	100
Capital	100	100
Royalty	100	100

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Date	Number of Wells	Gas Raw Volume E6m3	Gas Sales Volume E6m3	Water Volume E3m3	Injected Gas Volume E6m3	Gas Price $/GJ	Revenue M$	Operating Costs M$	Gas Royalty M$	Operating Income M$	Capital M$	Before Tax Cash Flow M$	Income Taxes M$	After Tax Cash Flow M$
2000(12)	0	0	0	0	0	0.49	0	0	0	0	42,435	-42,435	0	-42,435
2001(12)	50	77	73	581.9	154	0.49	1,337	1,497	67	-227	0	-227	0	-227
2002(12)	50	206	195	290.2	411	0.49	3,565	1,907	178	1,480	0	1,480	0	1,480
2003(12)	50	566	537	145.1	1,131	0.49	9,805	3,685	490	5,629	8,430	-2,801	0	-2,801
2004(12)	60	773	735	145.1	1,547	0.49	13,407	4,899	670	7,838	0	7,838	0	7,838
2005(12)	70	771	733	145.5	1,543	0.49	13,370	4,996	669	7,706	10,580	-2,874	0	-2,874
2006(12)	80	771	733	145.1	1,543	0.49	13,370	5,103	669	7,598	0	7,598	0	7,598
2007(12)	90	771	733	145.1	1,543	0.49	13,370	5,211	669	7,490	8,430	-940	0	-940
2008(12)	100	773	735	145.1	1,547	0.49	13,407	5,331	670	7,406	0	7,406	0	7,406
2009(12)	100	685	651	145.5	1,371	0.49	11,883	4,863	594	6,426	8,430	-2,004	0	-2,004
2010(12)	100	538	511	145.1	1,076	0.49	9,328	4,079	466	4,783	0	4,783	0	4,783
2011(12)	100	422	401	145.1	845	0.49	7,323	3,464	366	3,493	8,430	-4,937	0	-4,937
2012(12)	100	332	315	145.1	663	0.49	5,748	2,980	287	2,480	0	2,480	0	2,480
2013(12)	100	260	247	145.5	521	0.49	4,512	2,602	226	1,685	0	1,685	0	1,685
2014(12)	100	204	194	58	409	0.49	3,542	2,222	177	1,144	0	1,144	0	1,144
2015(12)	100	160	152	58	321	0.49	2,781	1,988	139	654	0	654	0	654
2016(12)	100	126	120	58	252	0.49	2,183	1,804	109	269	0	269	0	269
2017(12)	100	99	94	58.2	198	0.49	1,713	1,661	86	-33	0	-33	0	-33
2018(12)	100	78	74	58	155	0.49	1,345	1,547	67	-270	0	-270	0	-270
2019(12)	79	49	47	58	99	0.49	858	1,174	43	-359	0	-359	0	-359
Sub.		7,663	7,280	2,817.40	15,327		132,850	61,014	6,642	65,194	86,735	-21,541	0	-21,541
Rem.		0	0	348.5	0		0	328	0	-328	0	-328	0	-328
Total		7,663	7,280	3,165.90	15,327		132,850	61,341	6,642	64,866	86,735	-21,869	0	-21,869

Peep