Supply costs and utilisation concepts for coalbed methane in central and northern Queensland

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ABSTRACT

The availability of competitively priced gas from Central and Northern Queensland sources has the potential to provide a basis for significant industrial development in centres such as Townsville. Supply of natural gas to Mt. Isa has been under consideration for some time and could provide fuel use efficiencies and assist development of a number of projects in that area. Coals of the Galilee Basin, while poorly defined as a CBM resource, are extensive and offer the possibility that exploration could identify significant economically recoverable CBM reserves. Those of the North Bowen Basin have been under active field evaluation for a number of years. Conceptual estimates of the cost of supply of CBM to Townsville and Mt. Isa have been developed covering field production and pipeline transport costs. These have been based on available data on the Galilee coal resource and on relevant recent production techniques and well productivity experience from the CBM industry in the USA. Projections suggest that CBM can be delivered to Townsville at a price that could permit large scale development of core industries such as power generation, methanol and ammonia. Factors of key technical importance in setting costs of CBM supply including coal depth and gas content, well productivity, transport distance and scale of supply are examined. Alternative supply of CBM to Townsville from Bowen Basin sources is discussed.

INTRODUCTION

Prospects for large scale industrial development in North Queensland centres such as Townsville and Mt. Isa would be significantly enhanced by the availability of a gas supply at a cost competitive in fuels and chemical feedstock end-uses. These centres are remote from natural gas reserves with connection of Townsville into the Gladstone-Brisbane system requiring a gas pipeline of some 550 km. Connection of Mt. Isa to the South West Queensland Gas Centre or the Palm Valley to Darwin pipeline requires pipelines of 800 and 540 km respectively. Both centres are relatively close to major coal reserves. Townsville is within 250 km of both the north-eastern reaches of the Galilee Basin and the North Bowen Basin. Mt. Isa is within 350 km of significant reserves in the west of the Galilee Basin. The Coalbed Methane (CBM) potential of these coals may provide an economically attractive source of gas and studies commissioned by the Queensland Department of Business Industry and Regional Development have been carried out for both centres in which the likely costs of supply from Galilee Basin sources have been identified. The results are broadly applicable to other CBM sources and gas demand centres.

In the last 10 years, CBM production in the United States has reached the point where it is now becoming a significant contributor to overall natural gas supply. Gas production from coal seams in the two largest producing regions in the US, San Juan Basin - Fruitland coals in Colorado/New Mexico and the Black Warrior Basin in Alabama, in the first quarter 1991 amounted to 53.3 Bcf (59.6 PJ) or about 1.1% of total NG supply (Beck, 1992). Some 40 Bcf was produced from 1040 operating wells in the Fruitland coals and 13.3 Bcf from 2181 wells in the Black Warrior Basin (GRI, Nov. 1991). Total CBM production for 1991 is estimated at 270 Bcf. High levels of permitting and well completions were experienced during the period 1988-1990 under the influence of the Section 29 Unconventional Fuels Tax Credit of about US$0.86/Mcf available on production from wells drilled before the end of 1990. While the tax credit has been extended to apply to wells drilled before 1993 for production sold before 2003, both permitting and completions dropped during 1991. As completed wells reach peak production during the period 1992 - 1994, CBM is expected to contribute around 4% of US gas supply.

Research carried out in parallel with the growth in CBM production has focussed strongly on the understanding and prediction of factors affecting CBM producability. Important among these are techniques for multi-seam completions, well stimulation (hydro-fracturing), gas adsorption, coal bed permeability, and techniques for reservoir characterisation and production simulation.

Production of coalbed methane in Australia has been undertaken mostly as part of mine drainage activities. Appin Colliery and Westcliff in the Southern Sydney Basin generate power in excess of mine requirements at the 12 - 15 MW scale. (Bishop and Battino, 1989). Potential production from the North Bowen Basin coals in Queensland has been examined, most notably in the Broadmeadow Pilot Project in 1987/88 which 8 wells were completed into the Middle Goonyella seam. Initiated by Median Oil in 1987, the project demonstrated well gas flows of 40 - 100,000 cf/d from single seam completions at 500m depth into the 4.9m thick middle Goonyella seam (Reeves and O'Neill 1989). Results were not sufficiently encouraging to support commercial development at that time and further exploration and production testing in ATP 364P, containing an estimated 136 Tcf of CBM, has been taken up by MGC Resources Australia Pty Ltd (75%) and Mount Isa Mines Ltd (25%). Production testing is intended to continue on some of the existing wells and to include the completion of 9 new wells over the three year period 1991 - 1993. MGC's development objective is conversion of the gas to methanol.

Mount Isa Mines Ltd holds 100% interest in ATP 447 and ATP 391 in the Southern Bowen and is examining the potential for development of 100 MW of power generation using CBM. Drilling programs at Moura and Blackwater are about to be commenced and MIM has commissioned the CSIRO to assist in the development program over the next 3 years.

No exploration or production testing has been carried out for coalbed methane from Galilee Basin coals. Data available has been derived, in the main, from drilling of petroleum exploration wells. While the coal measures are extensive, the rank is lower than Bowen Basin coals. Conventional coal bed methane experience indicates that gas content increases with rank and depth of cover and that the rank should exceed that where the vitrinite reflectance is 0.70% for there to be an expectation of significant gas content. Rank of Galilee Basin coals in general only exceeds 0.70% at depth of cover greater than 1000m. There are, however, significant coal resources below this depth. In addition, there is little direct experience on the inseam gas content or gas composition with regard to depth of cover for low rank coals such as those in the Galilee Basin occurring above 1000m. Coal seam gas contents and gas composition are affected by many factors and even for higher rank coals, the methane potential of a seam and its permeability to the gas are uncertain in the absence of direct measurement. Any realistic estimate of the methane potential of Galilee Basin coals must await the outcome of exploratory drilling programmes.

Estimates of the likely costs of supply of coal bed methane to Townsville and Mt. Isa have, nevertheless, been made on the assumption of gas contents similar to those typically expected for high volatile coals at low depths of cover and well production characteristics similar to those experienced in the Black Warrior Basin in the US. Such estimates indicate the relationship between well depth, transport distance, well productivity, scale of supply and the delivered cost of gas at the demand centre. Estimates of the cost of gas sourced from various locations can be used to assess the scale and type of industries that may be able to utilise the resource. To the extent that the well productivity characteristics assumed are applicable, the results may also be applied to other coal resources such as those of the Bowen Basin.

Key industries that can be targeted as primary methane consumers include use as fuel in power generation and relacement of higher cost fuels in local industries, methanol production for export and downstream petrochemical processing and ammonia for direct sale or conversion to urea and MAP/DAP.

CONCEPTUAL SCHEME FOR SUPPLY

Well Productivity

In development of a CBM supply concept that can be used as a basis for estimating costs of supply, some very broad assumptions as to well productivity and reserve characteristics must be made. There is little data from the US CBM production regions that can be directly translated to indicate likely well performance characteristics for Northern Bowen or Galilee Basin coals. Publically available information on the performance of test wells in the North Bowen Basin (Reeves and O'Neill, 1989) is insufficient to fully demonstrate either the long term production profile for the wells or the production rates that may ultimately be achieved once reserve characteristics and optimum production techniques are understood. The absence of any direct measurements of gas content or composition for the Galilee Basin coals, and their low rank for which the conventional wisdom would suggest poor prospects for quality CBM reserves, means that any well productivity assumptions used for these coals are subject to a high degree of uncertainty.

Assumptions regarding well productivity and production profile have been based on an examination of CBM well productivities in the main US producing regions (Hobbs and Winkler, 1990). Wells in the San Juan region are prolific producers yielding typical peak productivities of 750 Mcf/d on a 320 acre spacing with typical gas content around 10 m^3/t. Black Warrior Basin wells typically yield 200 -260 Mcf/d peak production occurring approximately 1 year after start-up. Well spacing is 80 acres with gas contents around 12 m^3/t in 5 - 8m seams, and gas recovery is 60 - 65%. Appalachian Basin wells show lower peak productivities at 160 - 200 Mcf/d occurring 2.5 years after start-up with other characteristics broadly similar to the Black Warrior Basin. The range of typical peak well production rates in the various US Basins is shown in Figure 1. Production decline was modelled on data from non-gob wells in the Oak Grove pattern in the Black Warrior Basin (Clague and Alemian, 1988). The well profile assumed for General Queensland coals is based on a 150 Mcf/d peak production occurring 18 months after start-up. Production declines hyperbolically to 50% of peak after 45 months and 25% after 140 months as shown in Figure 2. The peak production rate is consistent with well deliverability projections for the Bowen Basin (Decker *et al.*, 1991). Gas content has been assumed at 5 m^3/t. This is consistent with expectations for High Volatile coals (Johnson and White, 1988), having $R_v > 0.70\%$ which is at the high rank end of available Galilee Basin data but is conservative for Bowen Basin coals. Well spacing was taken as 40 or 80 acres, dependent on aggregate seam thickness at the location considered, and gas recovery has been limited to around 40%.

Gas composition is assumed to be 98% methane as reported for the Broadmeadow Pilot Project (Reeves and O'Neill, 1989).

Field Development

In developing capital and operating cost estimates for CBM production, it is assumed producing fields would be arranged as satellites around the head of the main transport pipeline. Each field would be made up of blocks of 25 wells having a common low pressure gathering system, blower and delivery line to a field compressor station. Twenty five blocks would be linked to the compressor station to complete a field and deliver gas to the trunk pipeline head compressor station at around 2.8 MPag. Block and field areas for the Eastern Galilee location are 8 and 200 km^2 respectively, with a total reserve requirement of 1744 km^2 for 20 year supply at 88 PJ/y with a 10 year linear demand build-up.

Block completions would be scheduled to match gas demand but would average around 14 blocks (350 wells) per year in the demand build-up period and around 8 blocks (200 wells) per year thereafter for maintenance of 100 PJ/y wellhead production. Approximately 12% of produced gas is consumed in production, field compression and pipeline transportation operations.

COSTS OF GAS SUPPLY

Estimates of the delivered cost of CBM have been developed from capital and operating cost estimates for the field production and pipeline transport systems. Costs of supply take into account capital cost of facilities, gas consumption for the supply system, operating costs including labour, maintenance and other operating consumables, and the facility owner's return on investment. Components of cost of supply for field production and pipeline transportation have been analysed separately to allow for the distinctly different nature of investment in these types of facilities. Field production can potentially be distributed among a number of private sector owners. Pre-investment in production capacity is relatively low and reasonable returns available early in the life of production. Investment in a large scale pipeline system is likely to be associated with at least a 5 -10 year demand build-up period and consequently involves significant pre-investment in capacity. It is more likely that the transport system would be regarded as an infrastructure component with significant government investment through its early operating life.

Estimation of Field Production and Transport Costs

Levelised costs for field production and transport have been developed for the initial 20 years of project life from a DCF analysis on a before tax, 100% equity basis. The total cost for field production or transport is made up of operating and maintenance cost, depreciation, any royalty payable to resource or land owners, and operators' return on capital employed. A discount rate equal to the estimated real cost of capital is used to determine the 20 year NPV for the cost of supply. Table 1 shows the parameters used for field production and transport DCF calculations. The levelised cost of gas is the constant value for cost per unit of gas delivered over the 20 year period that yields the same NPV as the DCF calculation with fixed ROI.

Costs of Field Production

Capital costs for field production comprise well completion, low pressure block gathering and intermediate pressure unit gathering costs. Each unit has a gross production capacity around 12.9 PJ/y and delivers gas to the trunk pipeline head compressor station at 2.8 MPag (400 psig). Field production cost is most sensitive to well depth and well productivity. Table 2 shows the capital cost estimate for Galilee Basin locations - 300m deep Eastern Margin wells and 1200m deep South Pentland wells - under both base case and high well productivity (base case + 50%) assumptions. Figure 3 gives a breakdown of field capital cost for base productivity wells showing an increase from 37% to 70% field capital associated with a well depth increase from 300 to 1200m.

Levelised field production cost determined in the DCF calculations for the shallower Eastern Margin wells range from around $1.45/GJ to $2.10/GJ on a delivered cost basis dependent on the well productivity assumed. For wells in the South Pentland and West Winton areas, the range is $2.90/GJ to $4.30/GJ. Sensitivity of field production costs to scale of supply and demand build-up rates are relatively low. Figure 4 shows the dependence field production cost on well depth and well productivity. With the low expectation, in general, for finding significant CBM in coals having depth of cover less than about 250 m, the importance of identifying high productivity zones at depths shallower than about 600 m is clear if gas costs are to be competitive in projects such as large scale methanol or ammonia production.

Pipeline Transport Cost

The major supply scenarios considered are delivery of 88 PJ/y into Townsville from Galilee Basin production fields in the Eastern Margin or South Pentland regions, and 22 PJ/y into Mt. Isa from the Eastern Margin or West Winton regions. Pipeline configurations and pipeline and compressor station capital cost estimates are shown in Table 3.

Levelised transport cost is sensitive to the rate of demand build-up due to the underutilisation of capital in early years of pipeline operation. A 10 year demand build-up is assumed for the 88 PJ/y Townsville supply cases and 5 years for the 22 PJ/y Mt. Isa supply. Transport costs range from around $0.40/GJ to $0.60/GJ for the Townsville cases and $0.80/GJ to $1.70/GJ for the Mt. Isa cases as additionally shown in Table 3. The magnitude of the pre-investment effect is shown in Figure 5 where the year to year cost of transport is plotted with the levelised cost for the 88 PJ/y Eastern Margin to Townsville supply case. The importance of establishing high gas value projects early in the demand build-up in ameliorating this effect is obvious.

Total Cost of Supply

Cost of supply of CBM to Townsville at the 88 PJ/y scale assuming base case well productivity is estimated at around $2.40/GJ from 300m deep Eastern Margin wells and $4.80/GJ from 1200m deep South Pentland wells. High well productivity assumptions reduce these figures to around $1.80/GJ and $3.55/GJ respectively. Coal depth in general increases on moving from the Eastern Margin region deeper into the Galilee Basin, consequently gas costs intermediate between these figures could be expected for production from fields between Eastern Margin and South Pentland. Gas supply at the price levels indicated for Eastern Margin production can potentially support major industrial development in the Townsville region.

Costs of supply to Mt. Isa at the 22 PJ/y scale are estimated at $3.80/GJ from Eastern Margin and $5.15/GJ from West Winton. High productivity well costs would be around $3.20/GJ and $3.80/GJ respectively. CBM supply to Mt. Isa is, therefore, only likely to be competitive with the costs of natural gas from the South West Queensland Gas Centre or Palm Valley if highly productive fields can be proven in the shallow coal regions of the Eastern Galilee Basin.

Goonyella Middle seam coals in the Broadmeadow region of the Bowen Basin are at a typical depth of 500m (450 - 650m). The transport distance to Townsville is similar to that from the Eastern Margin of the Galilee Basin, approximately 250 km. Delivered cost of gas from this region based on the well productivity assumptions used here is estimated at around $3.20/GJ, for the 88 PJ/y scale of supply with a 10 year demand build-up. Figures 6 and 7 show generalised gas cost/well depth/transport distance relationship for these supply assumptions for demand levels of 22 and 88 PJ/y.

UTILISATION OPPORTUNITIES

Primary markets for CBM include methanol and ammonia production, and use as fuel either for general industrial use or power generation. Economic production of methanol and ammonia relies on use of large scale plant and relatively low gas prices. CBM used for supplying industrial and domestic fuel and power requirements can attract a relatively high price related to the cost fuels it replaces. A key secondary market for CBM is in large scale industrial power consumption such as that in aluminium smelting. A very low gas price is required in this instance for the industry to be competitive in world markets. There are significant economic benefits for some of these industries in being located close to established port facilities.

Industrial development based on these industries in Townsville involves minimum transport gas distances of around 250 km from North Bowen or the closest Galilee Basin coals. In order for the transport component of supply cost not to be unduly high it is necessary for development scenarios based on the establishment of a number of these industries building up to a demand level around 50 PJ/y or more to be proposed. One such scenario based on a 10 year build-up of demand to 88 PJ/y is outlined below. Maximum acceptable gas prices and gas demand for the user projects in the scenario are shown in Table 4. Industrial fuel uses include conversion of up to 10 PJ/y of liquid fuels but not coal. Additional power generating capacity is projected to be required to service growth in North Queensland demand during the 1990's. A 320 MW gas turbine power station operating at a 65% load factor has been included in the scenario. The maximum gas price is that required for a power send-out price of 6c /kWh and is significantly below the estimated current price of 8c/kWh for Townsville supply. Power station output approximates that for the Tully Millstream project (600 MW at 35% load factor). These first two projects are important contributors to early gas pipeline capacity utilisation. Ammonia production is set at 1150 tpd for supply into Australian markets and includes integrated urea production and supply of ammonia to fertiliser (MAP/DAP) production and nickel refining. Methanol production is assumed in a world scale 2,500 tpd plant supplying export markets. Base load power consumption of 640 MW is assumed at a power price of 2.5c /kWh. This would be attractive to an aluminium smelter and of a sufficient scale to support 300,000 tpa production. Timing of start-up of each project assumed in the scenario is also shown in the Table.

The maximum acceptable gas price, on a levelised basis, for this scenario is \$3.25/GJ. Referring to Figure 7 this can be seen to be consistent with supply from CBM reserves with average well depths to around 500 m for the base case well productivities assumed, and to around 650 m if 50% higher well productivities are assumed. Large scale gas users require gas at prices below the minimum projected costs for CBM based on shallow Galilee Eastern Margin coals. Should significant reserves be proved in this region it would still be necessary to establish a gas tariff schedule attractive to each of the industries involved.

Smaller scale scenarios can be considered. Industrial fuel and general use power generation located at Townsville, Projects 1 and 2, would consume around 22 PJ/y. Gas supply costs of around \$4.50/GJ could be acceptable and referring to Figure 6 may permit economic recovery of CBM from somewhat deeper coals.

Individual projects such as general use power generation and to a lesser extent methanol, considered in isolation, may be more economically located on the gas field with power transmission / product transport costs lower than gas pipeline transport costs. However, some of the potential for overall reduced costs of energy supply, viability of the large scale gas users and development of secondary markets may be lost in comparison to integrated regional development.

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DCF Parameter	Field Production	Pipeline
Return on Investment	12.5%	10.0%
Operating and Maintenance Costs	2.5%	2.0%
Royalties	4.0%	-
Depreciation	5.0%	5.0%
Discount Rate	10.0%	8.0%

Table 1. DCF calculation parameters

Well Characteristic	Eastern Margin	South Pentland
Well Depth (m)	300	1200
Base Case Productivity Wells:		
Cost/Well ($000's)	274	579
Cost/Annual Delivered PJ ($million)	15.1	32.0
High Productivity Wells:		
Cost/Well ($000's)	294	597
Cost/Annual Delivered PJ ($million)	10.8	22.0

Table 2. Field capital estimates

Route	Eastern Margin to Townsville	South Pentland to Townsville	West Winton to Mt. Isa	Eastern Margin to Mt. Isa
Line Length (kms)	250	400	350	700
Line Size (m)	0.71	0.66	0.41	0.41
Wellhead Capacity (PJ/y)	100	100	25	25
Delivered Capacity (PJ/y)	88	88	22	22
Capital Cost ($million)	280	180	115	230
Demand Build-up (years)	10	10	5	5
Transport Cost ($/GJ)	0.39	0.62	0.82	1.67

Table 3. **Pipeline capital cost estimates and transport costs**

Project Number	Description	Gas Consumption (PJ/y)	Maximum Gas Price ($/GJ)	Start-up Year
1	Industrial Fuel	14	5.50	1
2	Power Generation 65% LF	12.5	5.00	1
3	Ammonia	12.5	2.17	3
4	Methanol	28.5	2.19	5
5	Power Generation 100% LF	19.2	1.28	8
	Total Demand PJ/y	86.7		
	Levelised Gas Price $/GJ		3.25	

Table 4. Primary markets scenario

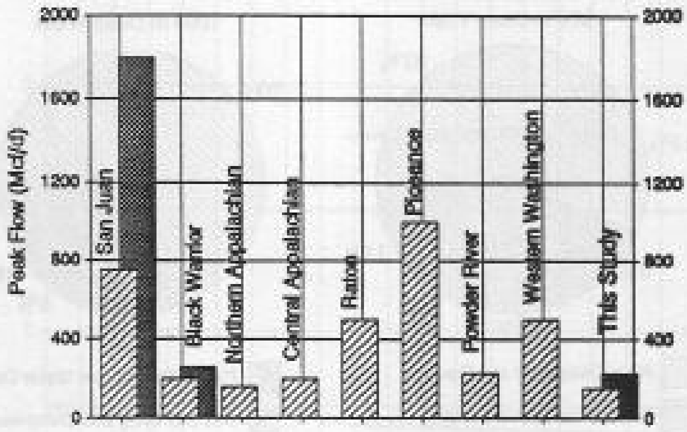

Figure 1. Peak well productivity - USA data. Average wells and good wells

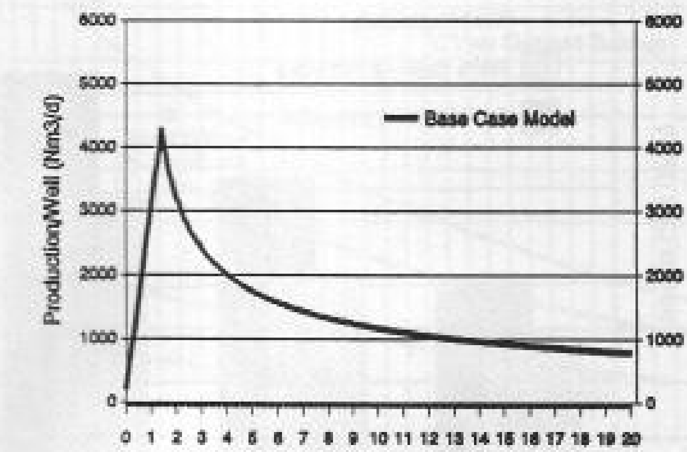

Figure 2. Well producivity. Production profile

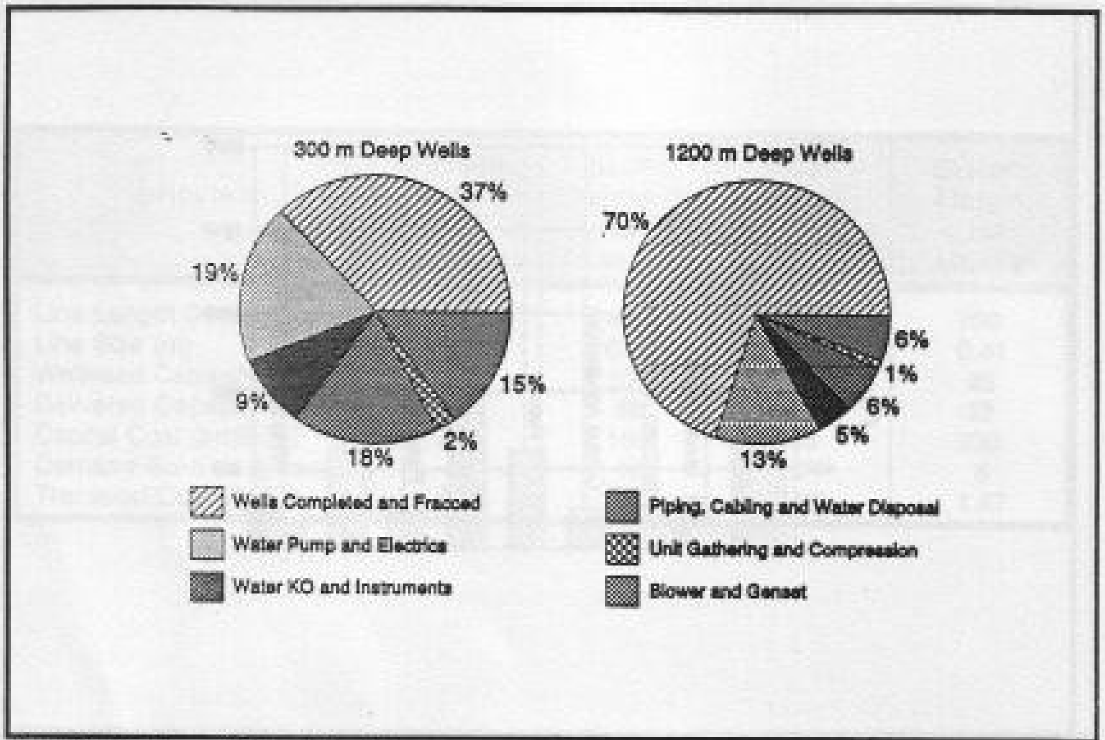

Figure 3. Field capital cost breakdown

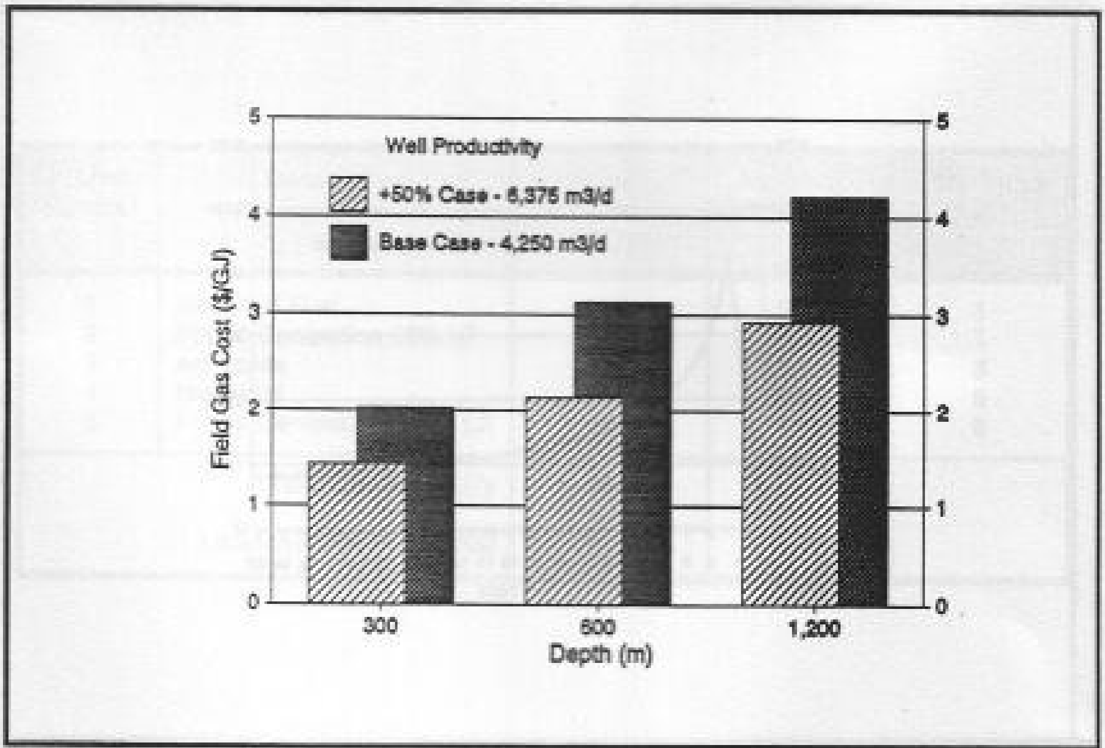

Figure 4. Levelised field production cost. Sensitivity to depth and well producivity

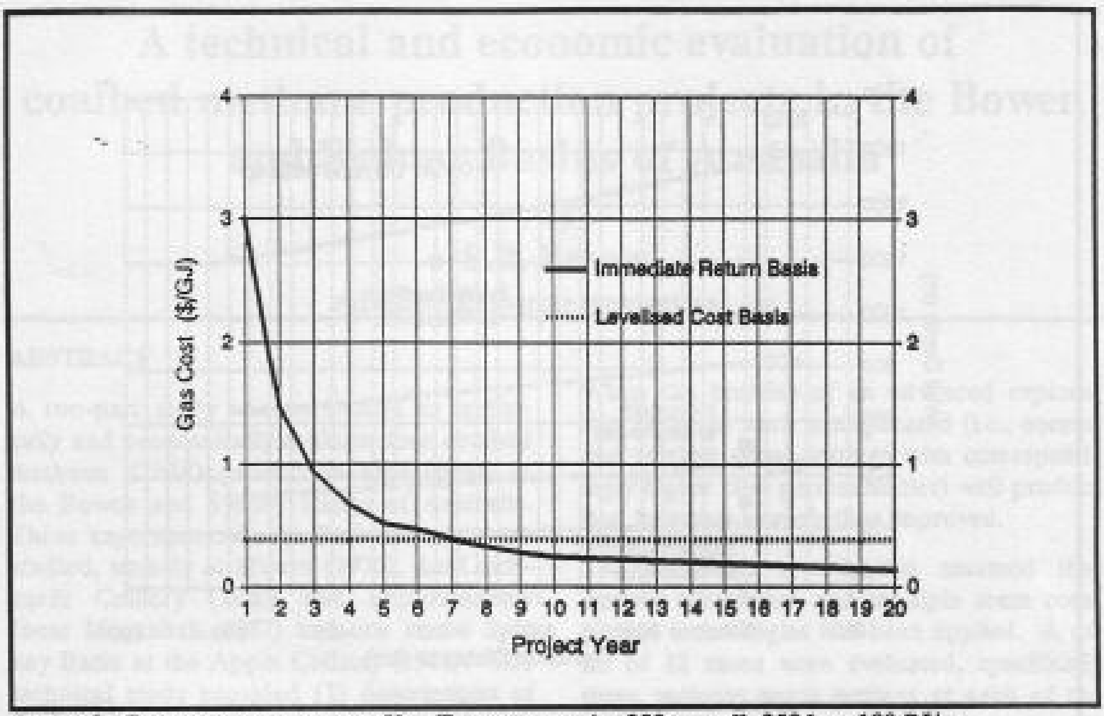

Figure 5. Gas transport cost profile. Eastern margin, 300 m well, 250 km, 100 PJ/y

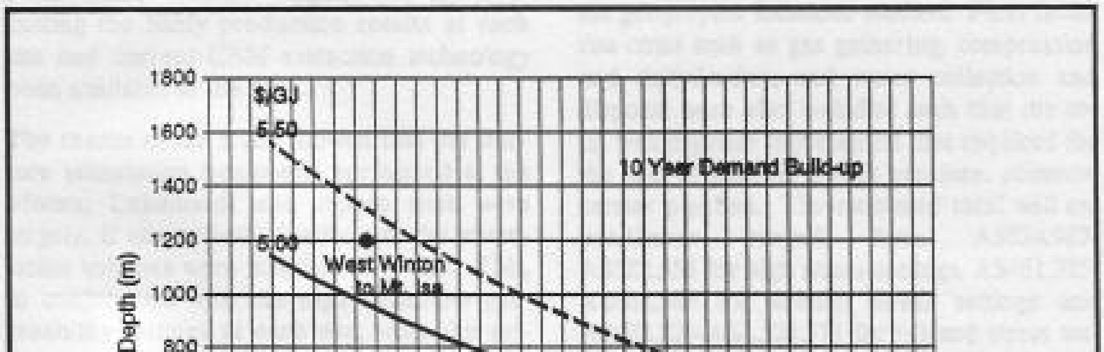

Figure 6. Delivered gas cost. 22 PJ/y delivered capacity

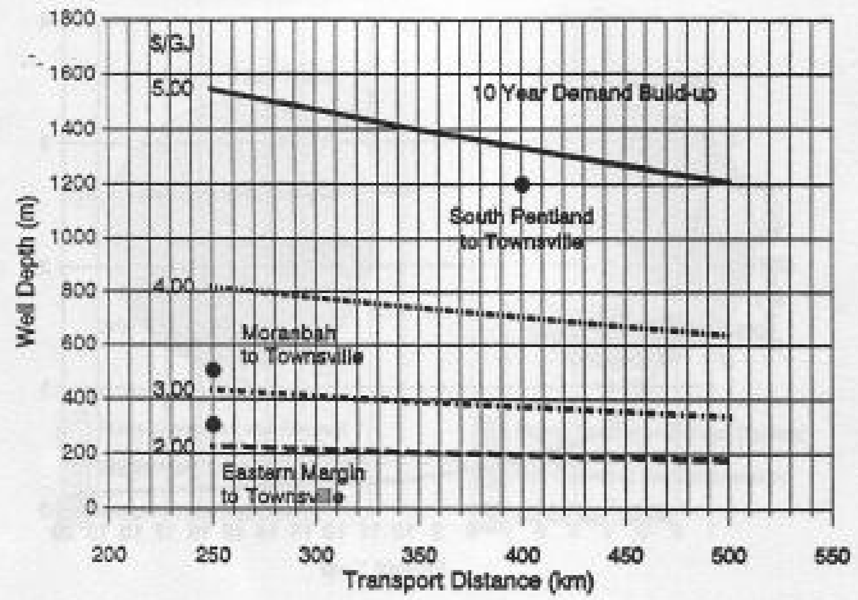

Figure 7. Delivered gas cost. 88 PJ/y delivered capacity