



National Energy  
Board

Office national  
de l'énergie

## **Briefing Note**

# **Overview and Economics of Horseshoe Canyon Coalbed Methane Development**

May 2007

**Canada**

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This briefing note, *Overview and Economics of Horseshoe Canyon Coalbed Methane Developments*, is the first in a new series of reports that will provide information on energy topics of interest to Canadians. It includes information on the development of coalbed methane in central Alberta from a geological formation called the Horseshoe Canyon. Commercial production from this unconventional gas resource was achieved in 2002. The information and analysis in this document provides a “snapshot-in-time view” that will be subject to changes in technology or market conditions for both price and costs.

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The NEB regulates the construction and operation of pipelines that cross international or provincial borders, as well as tolls and tariffs of those pipelines. International power lines are also regulated by the NEB, as well as some oil and gas exploration on frontier lands, particularly in Canada’s North and certain offshore areas. The import and export of natural gas and the export of oil, natural gas liquids and electricity also comes under the NEB’s jurisdiction.

In addition to its regulatory work, the NEB also collects and analyses information about Canadian energy markets and produces publications, reports and briefing notes based on this analysis.

Those wishing to rely on information from this briefing note in any regulatory proceeding before the NEB may submit the document, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and may be required to answer questions pertaining to the material.

# Chapter 1: Introduction

Coalbed methane (CBM) is natural gas contained in coal seams. It is primarily composed of methane, with variable amounts of nitrogen and carbon dioxide. Various other acronyms have been applied to CBM including coalbed gas (CBG, used in B.C.), coal seam gas (CSG, used in Australia) and natural gas in coal (NGC, which was created for use in Canada but has not been widely accepted). During formation of coal, organic material from plants and trees becomes coalified by the effects of heat, pressure and geologic time. During the process, large amounts of methane are generated and the majority of the methane is adsorbed (bonded) onto the surface area of the coal while smaller amounts are contained as free gas within the fracture system (called cleats) of the coal.

CBM is considered to be an unconventional gas because: it is both a source rock and a reservoir rock; of how the gas is stored; and, the manner in which the gas is produced. Coals generate and contain the gas internally, conventional reservoirs host gas sourced from other formations that migrate to the reservoir. The majority of gas in coal is bonded to the surface of the coal; gas in conventional reservoirs is contained in the free space (porosity) of the rock (see figure 1). Coal is a very efficient storage mechanism for gas, with coal capable of storing six to seven times more gas per unit volume of rock than conventional reservoirs. CBM is produced by reducing pressure to very low values to initiate production, and CBM production flow rates tend to be relatively low. In contrast, conventional reservoirs generally produce at higher rates and pressures and would be considered to be depleted, and the wells abandoned, at the low pressures of CBM production.

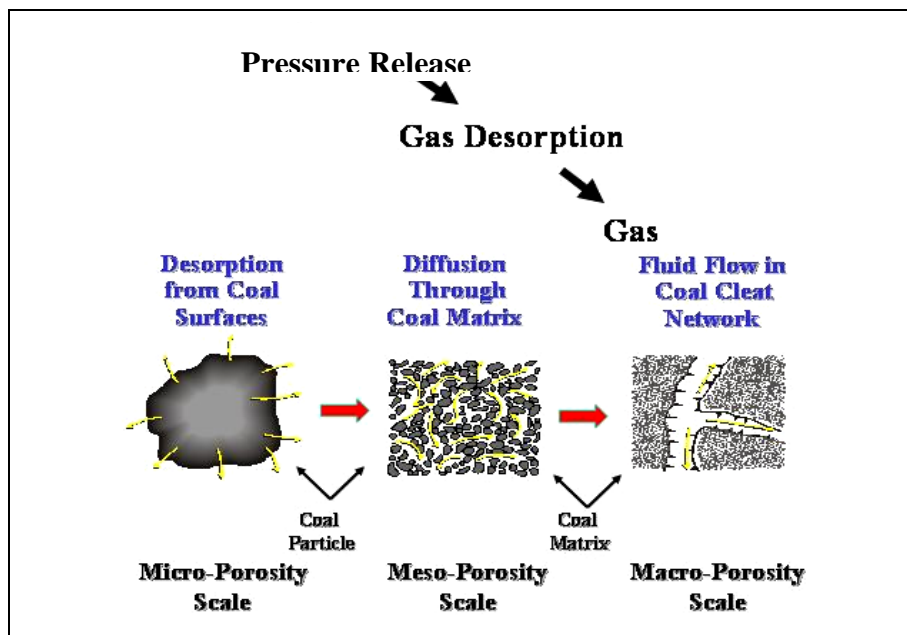


Figure 1

CBM Process (wet-type)

(Source: Trident Exploration Corporation, modified by NEB)

Canada's first CBM development started in 2002, in the Horseshoe Canyon Formation (HSC), and did not encounter any water. Most of the HSC CBM play consists of dry coal. These wells produce gas immediately, reach a peak production rate quickly and then begin a slow decline. Due to its short development history, the long term production profile for the HSC has yet to be determined. The production life of a CBM well can be very long (as much as 50 years is projected), but rates and pressures remain low throughout that time. Due to the low production pressures, compression is required to increase the pressure of the gas up to pipeline specifications.

Other potential CBM plays in Canada include the shallow Tertiary or Cretaceous Ardley coals in the Scollard Formation, located in west-central Alberta. This coal often contains fresh-water and as a result, has not been extensively tested to date. The Lower Cretaceous Mannville Formation contains thick seams of coal which contain salt water. Some commercial development has occurred in Alberta and the Board is closely monitoring developments. In British Columbia, the Lower Cretaceous Gates Formation has been tested in the northeast part of the province (contains salt water), the Jurassic Kootenay coals have been tested in the southeast part of the province (contains fresh water) and there is testing of the coals near Princeton in southern B.C. None of these projects have been confirmed as commercial. In Nova Scotia, the coals in the Stellarton and Cumberland Basins are also being tested, they contain brackish waters.

This briefing note will describe the geology of HSC coals; development history including issues related to development; regulatory requirement; economics of CBM development; and, future trends. CBM currently represents 3.7 per cent of Canadian gas production, up from virtually zero in 2002, with more than 85 per cent of that coming from the HSC.

**Key Message:**

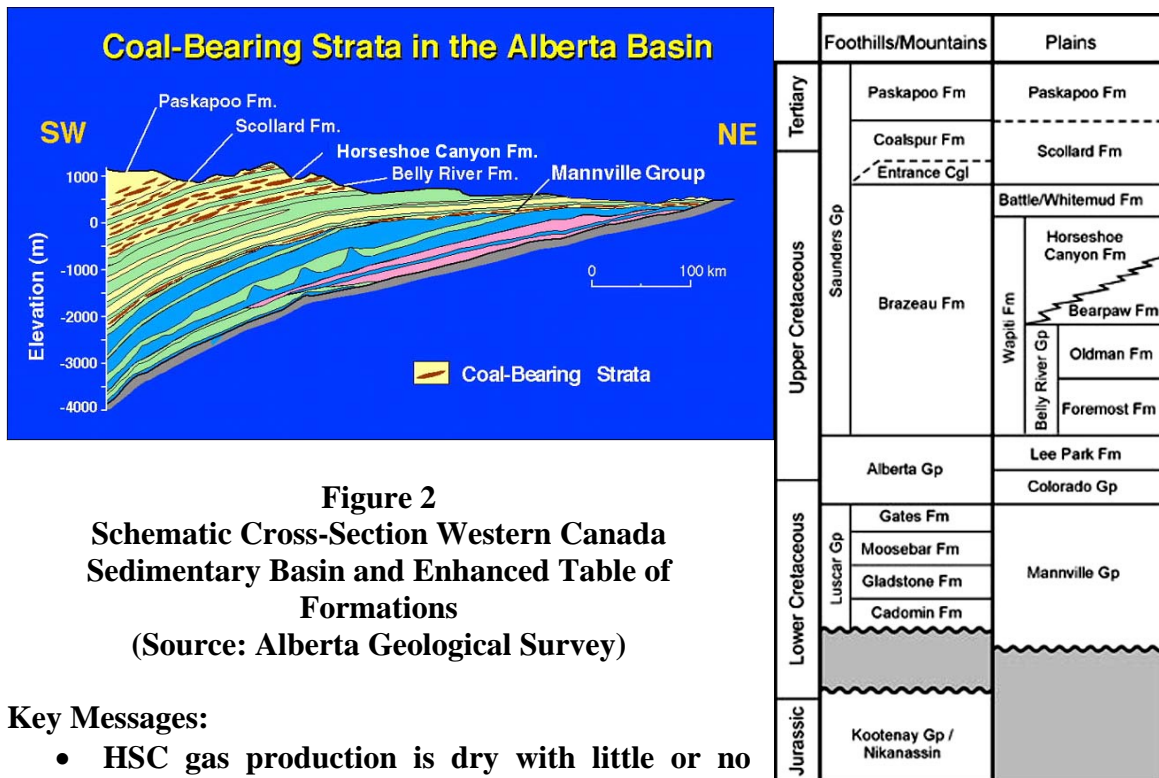
- **CBM is natural gas stored and produced in a different manner than conventional natural gas.**

## **Chapter 2: Geological Overview**

HSC coals tend to consist of several individual coal seams each less than 5m thick. One well would normally contact several of these coal seams for a total coal thickness of up to 30m. The prospective play area of HSC coal varies from as shallow as 200m in local areas to more than 1000m, along the western margin of the play area. HSC coals are interbedded with sand zones. The sands often contain conventional natural gas (which may have been sourced from the adjacent coalbeds). Production of the conventional gas found in these sands, along with the gas from the coal seams, results in a increased initial production rate for the well. The amount of production from the HSC play that is actually coming from conventional sands is still unknown. However, various estimates have been made by the companies involved and from outside observers that range from 10 to 40 per cent. As opposed to CBM development in the U.S., the HSC coals contain little to no internal water. As a result, there is no need to dewater the formation and gas production occurs very quickly with the production rate maximizing within a few months.

The lack of formation water is thought to be related to the under-pressuring of the sediments in this region, such that the entire sediment package is charged by gas. The regional under-pressuring may also be related to the melting of the continental glaciers of the last ice age and the subsequent rebound of the earth following removal of the weight of that ice.

The HSC Formation is found in the Upper part of the Cretaceous section (see figure 2). HSC coals are of relatively low rank in the sub-bituminous C to high volatile bituminous B range. Coal rank refers to the level of maturation of the coal. These coals tend to have low gas contents (but are fully saturated with methane), poorly-developed cleating, low permeability, and are under-pressured. Permeability is the key to successful operations as it controls the rate that the gas can flow to the well-bore. Average permeability in the HSC coals ranges from less than 5 milliDarcy (mD) to more than 40mD, and may be related to reservoir depth. Much of the early development focused on areas with higher permeability. Those were areas where the coals are warped over deeper geological structures such as Devonian reefs or significant sub-crop edges within the HSC play area. More recently, development has expanded laterally as companies better understand how to exploit the available permeability.



**Figure 2**  
**Schematic Cross-Section Western Canada**  
**Sedimentary Basin and Enhanced Table of**  
**Formations**  
 (Source: Alberta Geological Survey)

**Key Messages:**

- **HSC gas production is dry with little or no water production associated with the gas production.**
- **HSC coals are extensive, but often comprised of a large number of thin seams.**

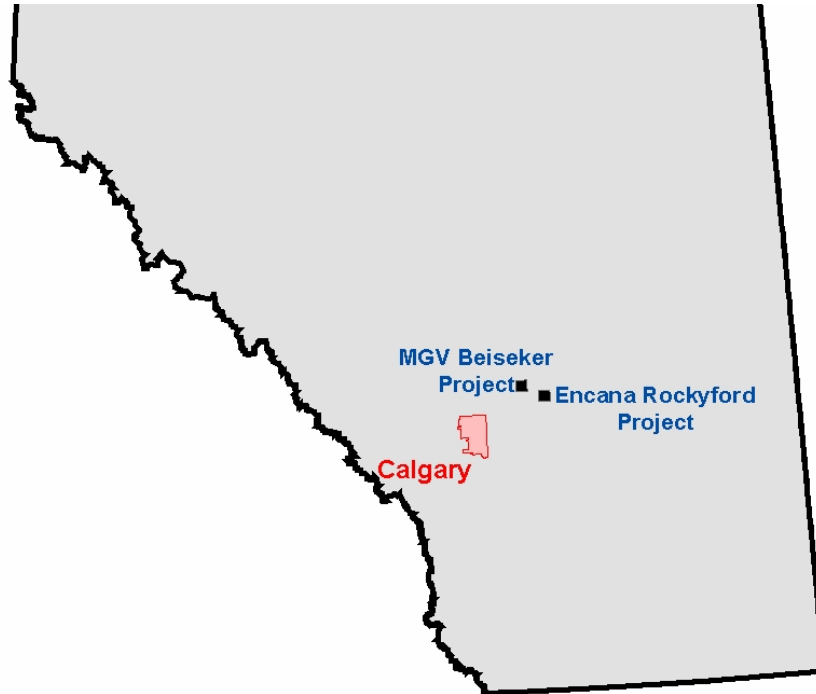
## **Chapter 3: Development History**

The presence of the HSC coals was well-known long before its CBM development. HSC coals were extensively mined in the Drumheller region where the coals are exposed at the surface through the wind and water erosion affiliated with the Red Deer River Valley and creation of the Alberta Badlands. The subsurface extent was confirmed by conventional oil and gas drilling that has taken place since the 1950s. Those wells targeted both the conventional sands in the Edmonton Group and the deeper Mississippian and Devonian formations thus adding to the knowledge of the entire Cretaceous sediment package.

In the United States, CBM production has been occurring since the 1970s. All developments to date have been from wet formations. Typically, a large contiguous land block was required for CBM development where coals have to be dewatered prior to gas production. CBM production in some areas, especially the Powder River Basin in Wyoming, caused problems for landowners, government bodies and environmental groups. The major concerns had to do with the rapid development of the resources, large volumes of produced water and some chemical reactions between the produced water and surface soils.

Initially, the HSC coals were not thought to be prospective for CBM due to their relatively shallow depth, low permeability, low gas contents and thin individual coal seams. Development of similar low quality coals in the Powder River Basin in Wyoming in the late 1990s provided incentive for companies in Canada to have a closer look at the HSC coals. The first programs were located near Calgary (see figure 3). Vertical wells were utilized due to the relatively shallow depths and the total thickness of the formation. However, companies found that drilling several wells in an area provided economies of scale in all facets of the development scheme.

Some experimentation was necessary in the early wells to identify successful techniques to adopt and unsuccessful techniques to avoid. It was found that drilling with coiled tubing in an underbalanced (mud weights less than hydrostatic pressure) scheme followed by multiple induced fracturing using nitrogen as the fluid, with little to no proppant (sand or beads used to keep the fracture open), provided the most cost-effective results (see figure 4). Coal has a higher affinity for adsorption of nitrogen molecules over methane molecules, thus the injection of nitrogen has an added benefit in releasing methane from the coals. Induced fractures are oriented in a northwest–southeast direction, parallel to the mountain front in the west, as that direction is perpendicular to the primary fractures or cleats in the coals. This exposes more of the cleats to the well bore. Four wells per section is deemed to be optimal for development, although there is some variation depending on the local geology in the coals.



**Figure 3** Location map of early Horseshoe Canyon projects (Source: NEB)



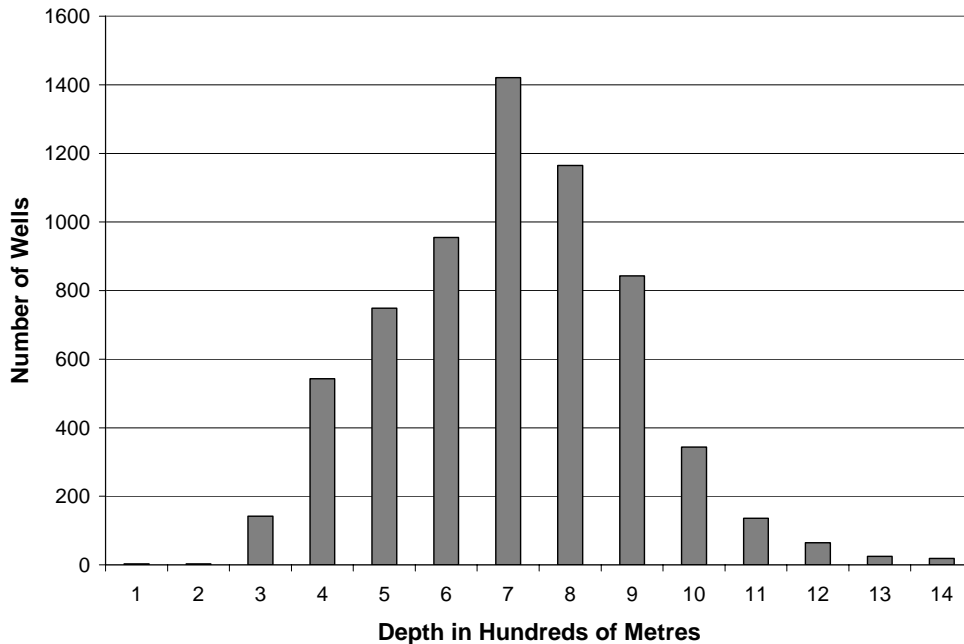
**Figure 4**  
**Typical Horseshoe Canyon nitrogen completion using coiled tubing**  
(Source: CSUG)

The HSC deposit is generally quite shallow with average well depth being about 700m deep (see figure 5). Shallowest wells are on the east side of the deposit and deeper wells are generally on the west side. The deeper wells shown in the graph are usually drilled for

a deeper conventional target and have been re-completed up-hole in the HSC for the CBM.

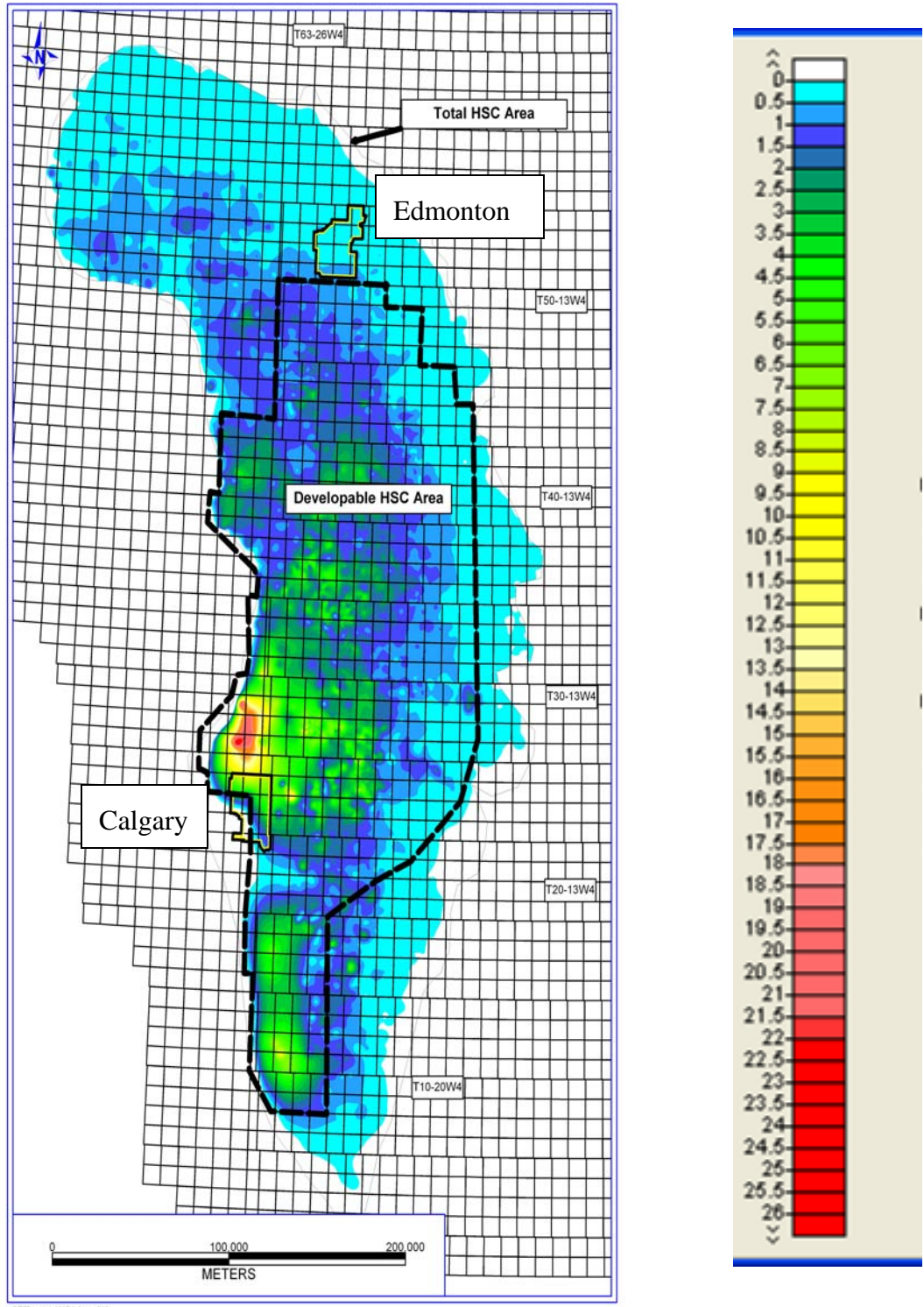
### Resource Estimates

Federal and provincial government studies and industry studies on the size of the resource were initiated shortly after development started in the HSC. However, they were and remain, hampered by the limited information available at this early stage of resource development. For the HSC coals, MGV, now Quicksilver, estimated 70 Tcf gas-in-place<sup>1</sup> in 2002. The Alberta Geological Survey (AGS) completed a study in 2004 outlining the entire region of the HSC play area and determining that it contained 66 Tcf GIP. The Canadian Gas Potential Committee (CGPC) estimated that there was 139 Tcf GIP in 2001 but reduced that to 54 Tcf GIP in 2005. How much is recoverable? Again, there is limited information available at this early stage of resource development. MGV estimated 13-23 Tcf in 2002, CGPC estimated 9 to 12 Tcf in 2005, Trident estimated 6 to 11 Tcf in the main development fairway in 2005. Canadian Energy Research Institute (CERI) and Canadian Society for Unconventional Gas (CSUG) published a report in late 2006 that indicated the HSC coals contained up to 36 Tcf of gas-in-place, with 30 Tcf developable and 10-12 Tcf recoverable (see figure 6). As development proceeds, additional information will become available to improve estimates of the recoverable volume.



**Figure 5**  
**Range of depths for HSC wells. (Source: NEB)**

1 Gas in place or GIP refers to the volume of gas in the ground.



**Figure 6**  
**Horseshoe Canyon Gas-In-Place Map showing Developable Area**  
 (Source: CER/CSUG)

## Regulatory Requirements

CBM is subject to the same EUB drilling, production, and operational rules and regulations as conventional natural gas. Alberta Energy also treats CBM as natural gas for royalty and tenure purposes<sup>2</sup>. Regulations cover water handling for both saline and non-saline water, air emissions for both flaring and venting, compression and noise levels, land access, well data requirements, public consultation requirements, royalty rates and the land tenure system. Please see the Energy and Utilities Board's Web site [www.eub.gov.ab.ca](http://www.eub.gov.ab.ca) for a list of the regulations.

Aquifer protection is a key issue for residents and landowners in the development area. Every oil and gas well passes through several groundwater aquifers. Well casing is cemented in place to protect groundwater aquifers prior to drilling into deeper formations. Under *Directive 056*, effective May 1, 2006, CBM developers must test all active water wells, either flowing or equipped with a pump, and all observation wells in the provincial Groundwater Observation Network within a minimum 600m radius of a proposed CBM well. Testing must be done prior to drilling a new CBM well or re-completing an existing well for CBM production where the completions will be at a depth above the Base of Groundwater Protection (BGWP). If no water wells are found within the 600m radius, testing must be conducted at the nearest water well within a 600 to 800m radius. Nearby land owners can also request testing of their water wells.

### Key Messages:

- **Experimentation was necessary to learn what processes work best in the HSC. Each coal formation is unique and needs to be understood geologically and technically before widespread production can occur.**
- **Estimates for the recoverable volume of gas in the HSC ranges from 6 to 12 Tcf. More production history is required to confirm the estimates.**

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2 For more information go to:  
EUB's EnerFAQs  
[http://www.eub.gov.ab.ca/portal/server.pt/gateway/PTARGS\\_0\\_0\\_257\\_229\\_0\\_43/http%3B/extContent/publishedcontent/publish/eub\\_home/public\\_zone/eub\\_process/enerfaqs/](http://www.eub.gov.ab.ca/portal/server.pt/gateway/PTARGS_0_0_257_229_0_43/http%3B/extContent/publishedcontent/publish/eub_home/public_zone/eub_process/enerfaqs/)  
Alberta Department of Energy  
<http://www.energy.gov.ab.ca/333.asp>  
For a list of directives covering CBM development see:  
<http://www.csug.ca/dl/ci-Guidelines.pdf>

## Chapter 4: Economics

The level of future HSC CBM development will be mainly determined by economics. The key factors impacting HSC CBM economics are:

1. Average well productivity,
2. Costs- drilling, completing, tie-in, and operating,
3. Gas price, and
4. Fiscal regime- royalties and taxes.

In this assessment, data relating to the above factors has been input into a model to determine three commonly used economic indicators:

- Internal rate of return (IRR),
- Net present value, discounted at 12 per cent (NPV12), and
- Undiscounted payout in years.

Each of the main data inputs feeding into the economic model are discussed below.

### Average Well Productivity

Large scale commercial development since 2003 has resulted in annual HSC CBM connections numbering approximately 500 in 2003, 1,500 in 2004, and 2,500 in 2005. This large number of connections provides a good basis for estimation of initial production characteristics for the average HSC CBM well. Due to the limited duration of the production history for this play, parameters that define the average well productivity over the longer term are more difficult to assess. As per the recent EMA “Short-term Canadian Natural Gas Deliverability, 2006-2008”, the NEB’s current assessment of HSC average well productivity in 2007 is defined by the following parameters:

Initial Well Productivity:	77 mcf/d
1 <sup>st</sup> Decline Rate:	5 per cent per year
2 <sup>nd</sup> Decline Rate:	15 per cent per year
Months to 2 <sup>nd</sup> Decline:	16
3 <sup>rd</sup> Decline Rate:	10 per cent per year
Months to 3 <sup>rd</sup> Decline:	60

The above parameters establish the “Base Case” of well productivity in this economic assessment. A second case of well productivity was also created, with initial productivity set at 65 mcf/d, a reduction of 15 per cent from the base case. This second case provides some insight on the economic impact of a lower average initial well productivity. Lower average initial well productivities can be expected as the HSC CBM development progresses.

### Costs

From discussions with CBM producers and certain published reports, the NEB has an estimate of the costs associated with HSC CBM development. The base case costs chosen for this economic assessment, in 2007 Canadian dollars, are as follows:

Well is Dry and Abandoned:  
Probability: 5 per cent  
Dry Hole Cost\*: \$150,000 per well

Well is Successful:  
Probability: 95 per cent  
Drill, Case & Complete\*: \$300,000 per well  
Tie-in Cost: \$150,000 per well  
Abandonment: \$21,000 per well

\* Note- includes \$8,000 per well for water well testing requirements.

Land Cost: \$15,000 per well

2007 Operating Costs\*\*:  
Custom Processing Cost: \$0.85 per mcf  
Fixed Well Operating Cost: \$700 per well per month  
Variable Well Operating Cost: \$0.20 per mcf

\*\* In the economic model, Future Operating Costs are obtained by applying an annual inflation factor of two per cent to the 2007 Operating Costs.

The above numbers were obtained recently from active CBM producers in the Horseshoe Canyon play and are believed to be good estimates of average development costs. The above numbers represent the base case cost scenario in this economic assessment.

### **Cost Escalation**

Escalating costs have become a major factor impacting resource development in general in the Western Canada Sedimentary Basin in recent years. Significant cost escalation has occurred since 2003, predominantly a period of high rig utilization levels and an increasingly tight labour market. Discussions with CBM producers indicate that cost inflation has been in the range of 15 per cent per year over the past three years or so.

Since the last quarter of 2006 a general slowdown in drilling activity in the WCSB has occurred, resulting in lower rig utilization. The slackening pace of drilling activity may exert some downward pressure on development costs and perhaps a return the levels of cost inflation that prevailed prior to 2003, around three per cent. Nevertheless, the impact of higher capital costs has been assessed in this economic evaluation. Two cases with higher capital costs (drilling, tie-in and land) have been run to provide insight into the impact of higher development costs; a case where capital costs were increased by 15 per cent from the base case, and a case where the capital costs were increased by 30 per cent from the base case.

In all cases, an inflation factor of two per cent per year was applied to operating costs subsequent to 2007.

## Gas Price

Gas prices can be very volatile. Since January 2006, the AECO C<sup>3</sup> monthly average gas price has been as high as 12.05 \$C/GJ (Jan. 2006) and as low as 4.49 \$C/GJ (Oct. 2006). In this economic evaluation, the AECO C gas price (in 2007 \$C) was varied between 4.00 \$C/GJ and 12.00 \$C/GJ for each case of well productivity and development cost. To obtain gas price in future years, an inflation factor of two per cent per year was applied.

## Fiscal Regime- Royalties and Taxes

The economic model applies the following regarding royalties and taxes:

- Royalty:
  - use current Alberta royalty formula for New Gas with Low Productivity Well Allowance applied
  - Royalty is reduced for the Gas Cost Allowance
- Taxes:
  - Net Annual Income is calculated for each year as Annual Revenue minus Annual Operating Costs minus Annual Royalties.
  - Annual Taxable Income is calculating from Net Annual Income by applying deductions relating to the depreciation of capital assets— Canadian Exploration Expenses, Canadian Development Expenses, Capital Cost Allowance, and Canadian Oil And Gas Property Expenses
  - The federal corporate tax applied to Annual Taxable Income is 22.14 per cent in 2007 and 21 per cent thereafter.
  - The provincial corporate tax applied to Annual Taxable Income is 10 per cent.

## Results of Economic Assessment

The two tables shown below present the economic indicators resulting from the various scenarios of initial well productivity, capital costs, and gas price. The first table is in reference to the NEB's current estimate of average well initial productivity for 2007. The second table presents economic indicators calculated on the basis of a lower average well initial productivity (65 mcf/d). The part of the first table highlighted in yellow shows the economic indicators for the base case under the various price scenarios.

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3 AECO C is a natural gas trading hub in Alberta, which is the major pricing point for Western Canada Sedimentary Basin natural gas. It is representative of intra-Alberta pricing; that is, the wholesale price of the gas for both sellers and buyers.

Case: Initial Well Productivity = 77 mcf/d,

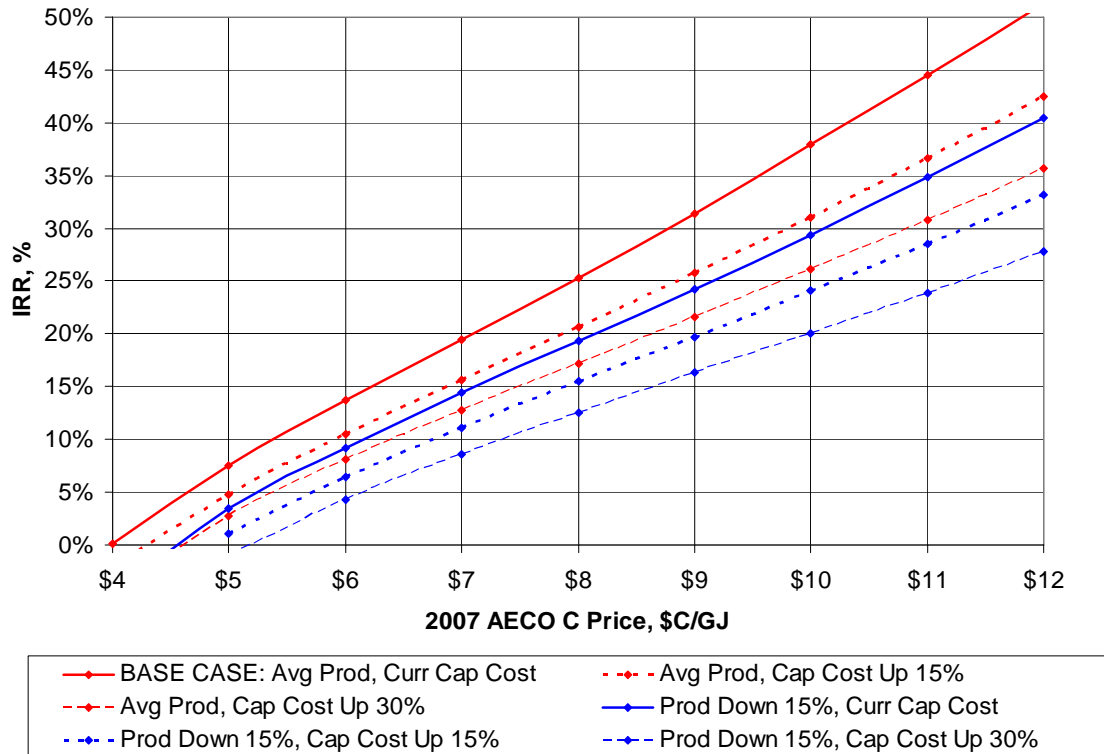
AECO C, \$/GJ	BASE CASE: Current Cap Costs			Current Cap Costs Increased by 15%			Current Cap Costs Increased by 30%		
	IRR, %	NPV (disc @ 12%)	Payout, Years	IRR, %	NPV (disc @ 12%)	Payout, Years	IRR, %	NPV (disc @ 12%)	Payout, Years
\$4.00	0.11%	-\$163,064	16.29	-2.11%	-\$222,126	Never	-4.97%	-\$285,128	Never
\$5.00	7.54%	-\$65,063	7.97	4.80%	-\$118,456	9.75	2.76%	-\$173,788	12.06
\$6.00	13.71%	\$25,758	5.68	10.55%	-\$25,044	6.73	8.06%	-\$76,928	7.89
\$7.00	19.46%	\$113,649	4.47	15.66%	\$64,139	5.23	12.72%	\$14,259	6.04
\$8.00	25.31%	\$201,765	3.72	20.65%	\$152,296	4.31	17.14%	\$102,827	4.94
\$9.00	31.42%	\$289,841	3.20	25.75%	\$240,355	3.68	21.55%	\$190,904	4.20
\$10.00	37.89%	\$378,169	2.80	31.06%	\$328,588	3.23	26.08%	\$279,146	3.65
\$11.00	44.50%	\$465,612	2.49	36.64%	\$416,844	2.87	30.78%	\$367,276	3.25
\$12.00	51.28%	\$552,495	2.27	42.43%	\$504,732	2.58	35.69%	\$455,553	2.93

Case: Initial Well Productivity = 65 mcf/d,

AECO C, \$/GJ	Current Cap Costs			Current Cap Costs Increased by 15%			Current Cap Costs Increased by 30%		
	IRR, %	NPV (disc @ 12%)	Payout, Years	IRR, %	NPV (disc @ 12%)	Payout, Years	IRR, %	NPV (disc @ 12%)	Payout, Years
\$4.00	-4.70%	-\$212,904	Never	-	-	-	-	-	-
\$5.00	3.45%	-\$120,463	10.82	1.03%	-\$176,754	14.40	-0.96%	-\$235,029	Never
\$6.00	9.22%	-\$40,566	7.27	6.49%	-\$92,867	8.66	4.25%	-\$147,243	10.46
\$7.00	14.40%	\$36,083	5.49	11.15%	-\$14,532	6.49	8.61%	-\$66,240	7.60
\$8.00	19.30%	\$110,823	4.49	15.49%	\$61,182	5.26	12.56%	\$11,116	6.08
\$9.00	24.27%	\$185,768	3.84	19.74%	\$136,168	4.44	16.33%	\$86,568	5.10
\$10.00	29.40%	\$260,620	3.34	24.05%	\$211,037	3.87	20.08%	\$161,455	4.40
\$11.00	34.79%	\$335,609	2.97	28.49%	\$285,931	3.42	23.89%	\$236,365	3.90
\$12.00	40.46%	\$410,673	2.67	33.12%	\$360,914	3.08	27.81%	\$311,286	3.48

Companies apply a minimum IRR level to their own activities. For the purpose of this report, the NEB assumes an IRR or hurdle rate of 15 per cent is required. Projects that do not meet the hurdle rate are usually not pursued, and those that do meet the hurdle rate are in competition with other projects for the company's available capital. In the Base Case (Current Capital Costs and 2007 well productivity) the hurdle rate is achieved at an AECO C price of just over 6 \$/GJ. All of the other scenarios are more pessimistic than the Base Case in terms of well productivity and/or capital costs, and the IRR calculated for these cases at various price levels (see figure 7).

Using the Base Case as the measure, this analysis indicates that HSC CBM is marginally economic for companies to pursue at the AECO C gas prices in the range of 6 to 7 \$/GJ, which is around the price range seen over the past few months. These marginal economics and concerns about further cost escalation are likely key factors behind the slowdown in CBM drilling activity that has occurred in Alberta since the last quarter of 2006. At AECO C prices below 6 \$/GJ the economics for HSC development are poor on average and even more severe drilling curtailments would likely occur under this price scenario.



**Figure 7**  
**IRR data from the above tables graphically.**

Cost escalation has been very high in recent years in the WCSB. The recent drop in drilling activity has left many rigs idle, changing the landscape with regard to escalating development costs. It is likely that development costs in 2007 will be a slightly lower than those in 2006. Nevertheless, the impact of escalating costs on IRR has been calculated and is shown graphically in Figure 7.

**Key Messages:**

- **Given an IRR hurdle rate of 15 per cent, with current capital costs and an initial well productivity rate of 77 mcf/d, a gas price of just over \$6/GJ is required over the lifetime of the well. With current gas prices this shows the marginal economics for companies of the HSC play, which is reflected in the slowdown in CBM drilling activity in Alberta since the fourth quarter of 2006.**
- **As development in the HSC progresses, average initial productivity is likely to decrease as the highest quality prospects are developed first. If average well initial productivity is reduced to 65 mcf/d, a gas price of \$7/GJ would be required to achieve an IRR hurdle rate of 15 per cent.**
- **Well economics are sensitive to capital cost escalations. For the base case a gas price of \$6/GJ yields a payout in less than six years. Adding 15 per cent to the capital costs adds just over a year to the payout, and lowers the IRR by about three per cent.**

## Chapter 5: Future Trends

### Development

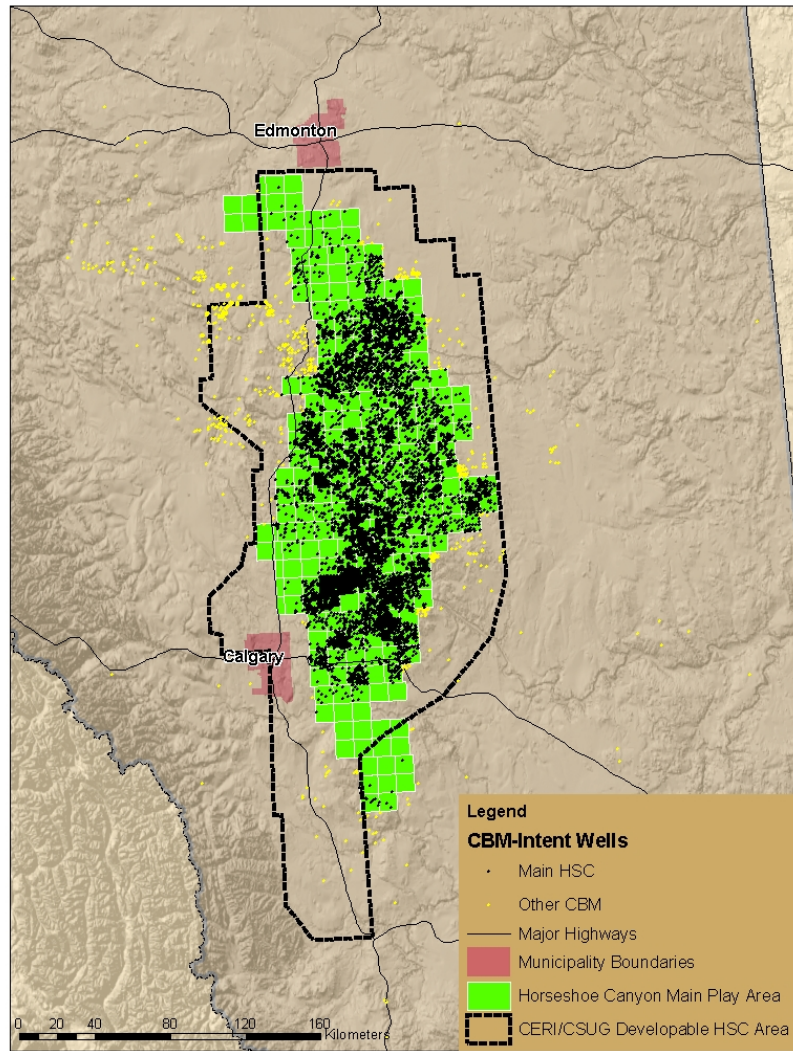
The CERI/CSUG November 2006 report included a map of the HSC play showing the GIP content of the HSC and made a decision to expect development only in areas where the GIP was greater than 0.5 Bcf/section (see figure 8). The NEB has defined a smaller area where most HSC development will occur using the following criteria:

- GIP greater than or equal to 2 Bcf/section.
- Exclude Townships where top of coal is deeper than 1000m.
- Exclude Townships encroaching on Calgary and Red Deer.

The NEB refers to this area as the HSC Main Play Area. Figure 8 shows the geographic extent of this area compared to the “Developable Area” defined in the CERI/CSUG report of November 2006. Figure 8 also shows the CBM wells drilled to date in the vicinity of the HSC Main Play Area, categorized as HSC Main Play and Other CBM. Mannville CBM wells are not shown on the map.

CBM plays are very sensitive to gas prices. As long as there is sufficient revenue to justify the expenses of development with a reasonable rate of return for the company, development will go ahead. This can be achieved by having a sufficiently high gas price or by using technological developments to reduce costs in all area of development or by some combination of the two.

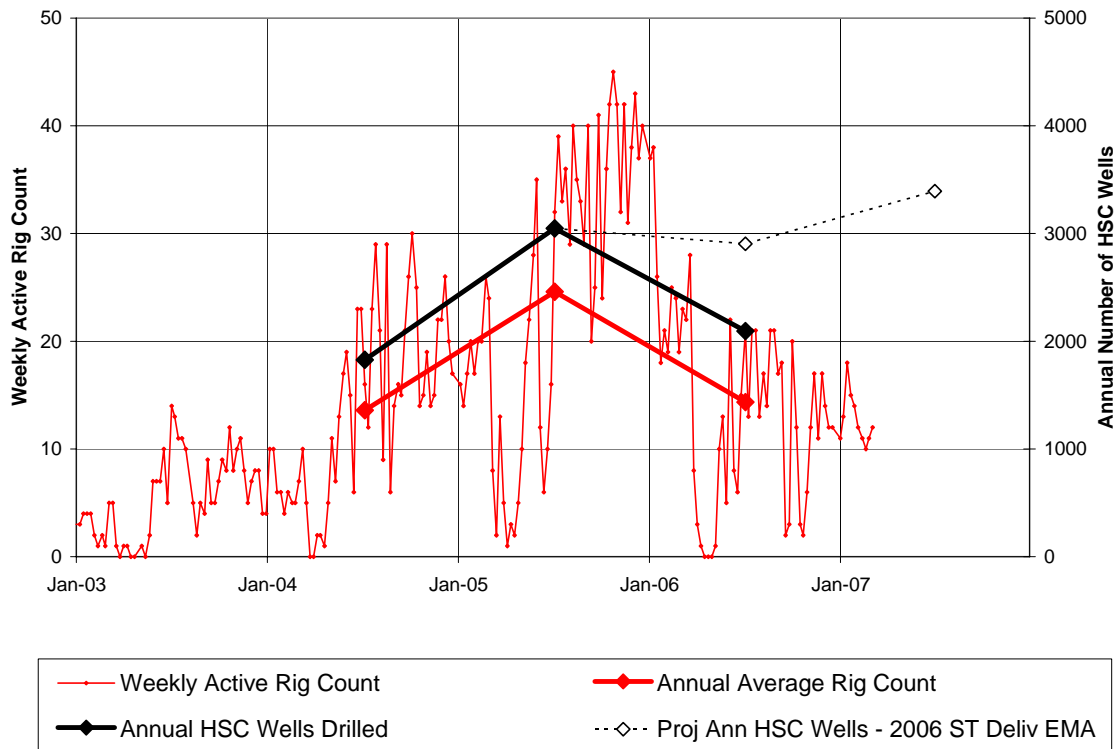
An example of cost cutting in the development stage for HSC CBM is “built-for-purpose” rigs. Industry has built special coiled tubing rigs that are smaller and more mobile than conventional rigs. These coiled tubing rigs can drill a well to about 900m in as little as 12 hours, without the need for wide roads or expensive pad preparation in advance of drilling. There are 40 of these rigs now available and in total; they can drill in excess of 3,000 wells annually. One drilling company has responded to this challenge and has modified its conventional rigs to be more mobile to compete with the coiled tubing rigs. Conventional rigs have the advantage of using drill pipe that can last for many wells versus use of a string of coiled tubing that only lasts about a month and costs \$60,000.



**Figure 8**  
**Horseshoe Canyon Main Play Area and CBM Wells**

Development is still in its early stages (six years) and HSC wells are expected to produce for 40 to 50 years. Until some longer term production history is available, there will be uncertainty associated with the total amount of the resource to be recovered. Within the next five years there should be sufficient information available to support a better estimate of the recoverable resources of the HSC.

The level of HSC CBM development is directly proportional to the activity of shallow rigs operating inside the HSC Main Play Area. For the purposes of this report, shallow rigs are those with depth capacity between 800m and 2000m. In the past three years (2004 – 2006), approximately 95 per cent of all HSC CBM wells have been drilled by shallow rigs. Shallow rigs working within the HSC Main Play Area over the past three years were engaged in drilling for HSC CBM about 83 per cent of the time.



**Figure 9**  
**Active Rig Count For Shallow Rigs in HSC Main Play Area and Annual HSC Wells.**

Figure 9 shows the weekly and average annual active rig count for these shallow rigs operating in the HSC Main Play Area (left axis) and the annual number of HSC wells drilled (right axis). The strong correlation between shallow rig activity in the HSC Main Play Area and the level of HSC development is evident on this chart

Several factors have acted to constrain HSC drilling activity in 2006, and these factors are expected to continue to influence the pace of development for the next several years. Marginal economics, resulting from the recent gas price environment and rising development costs, have been the biggest factor constraining HSC development since mid-2006. Many producers scaled back their drilling programs in response to the economics resulting in the decreased level of HSC drilling activity seen in 2006.

Other factors include some land-owner resistance to development in the Calgary-Edmonton corridor, and also that development of the easiest and most attractive acreage tends to occur first, with the remaining undeveloped acreage being more difficult and less attractive. The most attractive acreage exists in situations of higher quality resource and large concentrated land holdings with undisputed title to CBM.

In 2007, price uncertainty and marginal economics are expected to continue to constrain HSC drilling activity. It is expected that Horseshoe Canyon CBM drilling activity in 2007 will be somewhat lower than what occurred in 2006.

While an increase in gas price will create a climate more conducive to development, it is not expected that such an occurrence will impact drilling plans for 2007. The drilling programs for 2007 have been established and price swings one way or the other are not likely to significantly impact these plans. Higher gas prices over the longer term will positively impact HSC development, but the drilling constraints discussed previously will serve to limit the pace of the development over the longer term. Thus the drilling expectations over the longer term are estimated to be in the range of 2,000 wells per year--significantly less aggressive than earlier expectations.

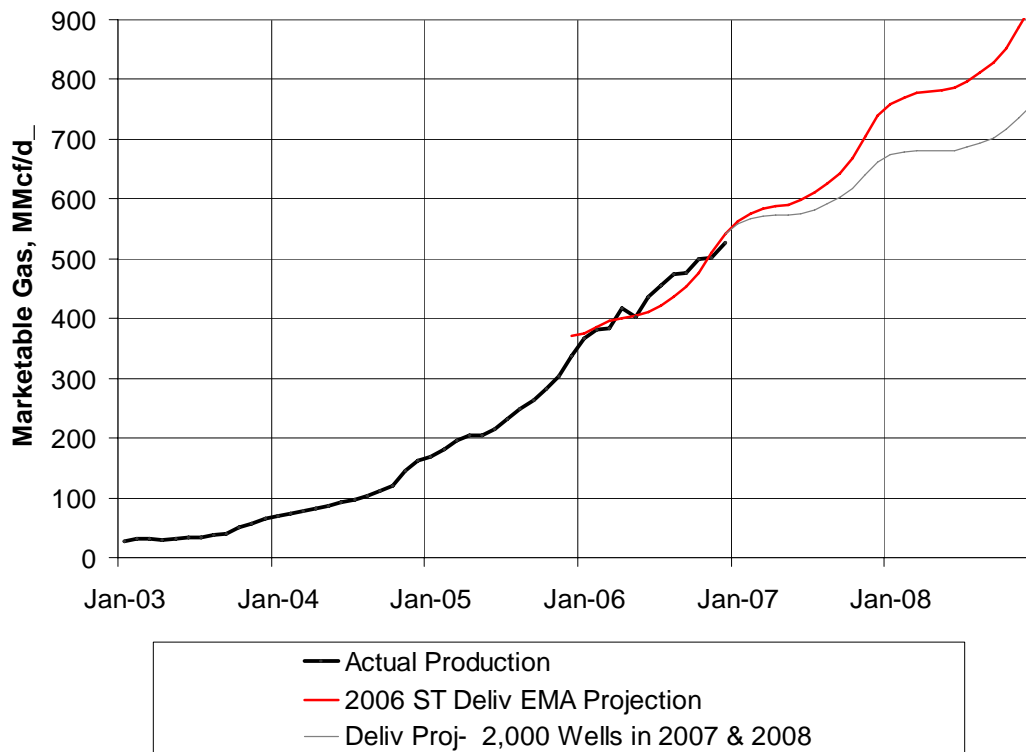
#### **Horseshoe Canyon Annual Wells Drilled**

<b>Year</b>	<b>Number of Wells</b>
2003	590
2004	1824
2005	3046
2006	2089

Source: NEB Analysis of GeoScout well data as of March 28, 2007

#### **Production**

Horseshoe Canyon gas production has grown rapidly with the commercial development that has occurred since 2003, as shown in Figure 10. Future deliverability from this resource will largely depend on the rate of development-- that is the drilling activity directed towards Horseshoe Canyon CBM. Figure 10 shows a projection of Horseshoe deliverability with a development level of approximately 2,000 wells per year in 2007 and 2008. Under this scenario Horseshoe Canyon gas production is expected to increase from 540 MMcf/d at the start of 2007 to approximately 750 MMcf/d at the end of 2008.



**Figure 10**  
**HSC CBM Production History & Deliverability Projection**

**Key Messages:**

**Activity**

- HSC drilling activity in 2006 was about 2/3 of the 2005 level.
- HSC drilling in 2007 and 2008 is expected to be approximately 2,000 wells in each year.
- There is an abundance of possible drilling locations and drilling capacity, but the pace of development will reflect factors such as regulatory requirements, aggregation of appropriate land positions, and market conditions.
- At present the key impediment to higher drilling is marginal economics at gas prices seen over the past year. Average AECO C Price for the past 12 months has been \$6.20/GJ resulting in marginal economic returns.
- Gas price swings in 2007 are not expected to significantly alter 2007 drilling plans. Over the longer term, the margin between gas prices and costs will be a key factor driving activity level.

**Production**

- HSC production was roughly 525 MMcf/d at the end of 2006, and is expected to reach 750 MMcf/d by the end of 2008.

## Chapter 6: Summary

Key aspect of the development of Horseshoe Canyon CBM resources in Alberta include:

### Resource and performance

- Large remaining resource base estimated at 6 to 12 Tcf or more
- Conservative estimate of 25,000 well locations in the HSC Main Play area with only about 7,500 drilled to end of 2006. At roughly 300 MMcf recoverable per well, 25,000 well locations represents about 7.5 Tcf.
- Wells are expected to have shallow decline rates and long production lives. However, given the short production history, long-term performance and ultimate resource recovery is speculative at this point.

### Industry Activity

- Escalating costs and softening gas prices have resulted in a reduction of HSC CBM drilling from 3,000 wells in 2005 to 2,000 in 2006.
- About 2,000 new HSC CBM wells per year are expected for the next several years
- At this pace it would take about another 9 years to drill up the estimated prospects in the HSC Main Play area

### Economics

- As utilization of purpose-built drilling equipment drops, reductions in costs may occur and help to improve economics
- We estimate new HSC CBM wells to be economic at just over \$6/GJ even at today's inflated costs. However, wells with below average performance or further cost escalation could push this threshold above \$7/GJ
- Long production period for CBM wells makes for an extended payout and increases exposure to long-term natural gas.

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