DRAFT
FINAL REPORT
&
RECOMMENDATIONS

of the

NATURAL GAS IN COAL
ROYALTY WORKING GROUP

to the

MULTI STAKEHOLDER
ADVISORY COMMITTEE

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EXECUTIVE SUMMARY

Background

In 2003, a royalty working group (RWG) was formed as part of the CBM/NGC Multi-Stakeholder Advisory Committee (MAC) to address the question of whether the current natural gas royalty structure is appropriate for the development of the natural gas in coal resource in Alberta. The RWG, chaired by the Alberta Department of Energy (ADOE), included members from the Alberta Government, the Freehold Owners Association, the Alberta Association of Municipal Districts & Counties, and representatives from industry. The RWG focused on the issues directly related to the economics of NGC development on Crown lands in Alberta, specifically those relating to both the short term and long term appropriateness of the natural gas royalty regime. While not the focus of the RWG, issues related to NGC development on freehold lands were also discussed.

In an atmosphere of open dialogue among its stakeholders/members, the work of the RWG was guided by the principle that petroleum and natural gas rights should be managed as effectively and efficiently as possible. This includes recognizing the need for a healthy and safe working environment, respecting the environmental concerns of all Albertans, and optimizing the economic benefits for present and future generations of Albertans. Specific business and economics principles include:

- Albertans receive a fair share for the development of their resources;
- Alberta has the appropriate natural gas royalty regime in place for the responsible development of the NGC resource; and,
- Industry receives the proper reward and recognition for risks and uncertainty taken and managed in developing this new resource.

The Alberta Geological Survey (AGS) estimates that there is potentially about 514 trillion cubic feet (Tcf) of natural gas in coal in place in Alberta. This is almost double the estimate of conventional natural gas in place in Alberta of 260 Tcf. There is not yet enough information to make a meaningful approximation of how much of the NGC is recoverable. Of the 514 Tcf of gas in place, 57 Tcf is estimated to be in the Ardley formation, 71 Tcf in Horseshoe Canyon, 147 Tcf in Belly River and 239 Tcf is calculated to be located in Mannville coal formations. The AGS estimates that nearly 80% of this NGC potential is located on Crown lands.

The two coal formations that have received the most attention to date have been the Horseshoe Canyon and the Mannville formations. Although the Scollard (Ardley) coal formation has also been identified as having the potential for development, industry has conducted little activity into this formation. The Horseshoe Canyon formation is predominantly shallow and dry, whereas the Mannville formation is deeper and is generally associated with large volumes of saline water. Although exploration activity began in both formations at roughly the same time, the Horseshoe Canyon formation is the only coal seam where significant commercial development of NGC is currently occurring.

Findings

The ADOE conducted economic analysis on the Horseshoe Canyon and on Mannville coal formations to represent a cross-section of both dry and wet coal seams. Industry aided the process by sharing its understanding of the critical parameters and by providing data to the ADOE. The results were compared with third party research from sources such as the National Energy Board, investment banks, and consultants. The results indicate that the Horseshoe Canyon is very comparable to conventional shallow gas development in southeast Alberta, whereas the Mannville is considerably less favourable on a well-by-well basis than conventional natural gas developments of similar depth and size in areas of central Alberta.

Industry has suggested that the cost of producing natural gas from water-bearing coal seams such as the Mannville is incrementally higher than the cost of other natural gas development. Industry has therefore requested that the government provide royalty acknowledgement of the additional costs of water handling and disposal associated with NGC development. Several options for how these costs could be incorporated were identified by the RWG (Appendix 3).

The results of the economic analysis completed for the Mannville formations are not conclusive. Without further drilling results many of the key parameters are still uncertain.

The RWG observed that the analysis indicates that some form of fiscal recognition appears reasonable to facilitate drilling more wells in order to acquire better knowledge of the wet-coal resource and to encourage development of this large resource. In this context, industry pointed to the past successes that Alberta has had in encouraging the development of resources such as oil sands, deep gas, and enhanced oil recovery.

The RWG also raised the fact that in the United States, early NGC development was assisted by a credit against federal income tax. In this context, it was pointed out that NGC is not unique to Alberta, and therefore, if assistance is needed, Alberta's royalties should not have to shoulder the entire burden. Other provinces with NGC potential include British Columbia, Saskatchewan, Ontario, and Nova Scotia. British Columbia has already implemented a program to encourage NGC development. Alberta currently has the most active investment in NGC.

Crown royalties will not impact freehold properties; this is another reason why industry's concerns can also be assisted through specific recognition of NGC in the federal and provincial income tax formula.

Conclusions

- Horseshoe Canyon dry coal development has been shown to be commercially viable;

- Mannville economic results are not conclusive; there is no clear-cut determination that this NGC play is or is not economically viable based on our current level of understanding. Drilling activity clearly shows that industry has not pursued development of the Mannville as aggressively as the Horseshoe Canyon;

- The most significant variables in determining the economic outcome in the Mannville coals are price, gas and water production, water to gas ratio, and water disposal costs. With price determined by the market place and the royalty formula already sensitive to price, it appears at this stage that water handling and disposal are the key issues that need further investigation.

- The economic results of wet coals indicate that these NGC projects may not be economically viable under current conditions. This puts an estimated two-thirds of the NGC resource at risk of not being developed.

Recommendations

- *The ADOE should consider some form of short-term royalty program immediately to facilitate drilling more wells in order to acquire better knowledge of the wet-coal resource. The objective of this program, which may or may not be continued beyond the early evaluation phase of the resource development, would be to increase the information about these types of coal seams and allow for better assessment of their economic viability as soon as possible.*

- *Alberta and Federal Canadian governments should consider specifically recognizing Canada's NGC potential through their respective corporate income tax formulas.*

PART ONE

1.0. Introduction

1.0.0. Purpose

The purpose of this report is to determine if Alberta's present natural gas royalty regime is appropriate for existing and anticipated future development of natural gas in coal (NGC) in Alberta; and where appropriate, to recommend changes within the existing overall royalty policy and framework.

2.0.0. The Consultation Process

1.0.0.0. History

In January 2001 the Alberta Department of Energy (ADOE) commissioned a study[1] to examine the potential for NGC (also referred to as coal bed methane – CBM) development in Alberta. The objectives of this study were:

- Develop an increased understanding of the NGC resource base;
- Examine the fiscal environment necessary for appropriate economic development of NGC; and,
- Determine potential strategies to consider in the development of the NGC resource.

In 2002, ADOE initiated an external consultation process including the formation of two working groups to gather data and information to assess land tenure and royalty issues.

Following from the initial consultation process, a multi stakeholder advisory committee (MAC) was established in 2003. The stakeholders represented on the MAC include representatives from environmental organizations, landowners, agriculture, local government, the energy industry, and provincial government departments. Stakeholder organizations nominated members to represent their interests.

Under the MAC, the initial working groups (tenure and royalty) were expanded to include groups to assess surface/air issues and water issues, and the royalty working group was expanded to include ADOE, the Alberta Energy and Utility Board (EUB), the Canadian Association of Petroleum Producers (CAPP), the Canadian Society for Unconventional Gas (CSUG), the Small Explorers and Producers of Canada (SEPAC), the Freehold Owners Association (FHOA), the Alberta Association of Municipal Districts & Counties (AAMDC), and a number of individual companies - Anadarko Canada Corporation, CDX Canada Co., EnCana Corporation, Luscar Ltd. and MGV Energy Inc.. A detailed list of committee members is located in Appendix 1.

2.0.0.0. The NGC Royalty Working Group (RWG)

The initial meeting of the royalty working group (RWG) took place in March of 2003. Throughout the consultation process the Department of Energy has worked with industry associations and individual company representatives to ensure that the best possible understanding of the economic issues was realized. Excellent cooperation of group members was achieved.

Charged with making recommendations to the MAC, the RWG was assigned the following major objective: determine if the existing natural gas royalty regime is appropriate for NGC development and suggest recommendations where appropriate, and within the existing overall royalty policy, to accommodate responsible NGC development.

Scope: The RWG focused on the issues directly related to the economics of NGC development on Crown lands in Alberta, specifically those relating to both the short term and long term appropriateness of the natural gas royalty regime. Mindful watch was also kept on related issues for NGC development on freehold lands.

Guiding Principles: In an atmosphere of open dialogue among its stakeholders/members, the work of the RWG was guided by the principle that petroleum and natural gas rights should be managed as effectively and efficiently as possible. This includes recognizing the need for a healthy and safe working environment, respecting the environmental concerns of all Albertans, and optimizing the economic benefits for present and future generations of Albertans. Specific business and economics principles include:

- Albertans receive a fair share for the development of their resources;
- Alberta has the appropriate natural gas royalty regime in place for the responsible development of the NGC resource; and,
- Industry receives the proper reward and recognition for risks and uncertainty taken and managed in developing this new resource.

The RWG adhered to the following principles and roles:

- Encourage and support open and honest communication:
- Encourage an open and free-flowing exchange of information;
- The consultation process should be collaborative and consultative with meetings that allow for open discussion;
- The administrative burden for both industry and government should be minimized; and
- The Chair and ADOE members were to administer and facilitate the consultation process.

3.0.0. Alberta's Natural Gas Royalty Regime

4.0.0.0. Business Principles and Royalty Policy

Alberta's royalty policy is to achieve a "fair" share of the benefits from the development of the Province's energy and mineral resources for Albertans. This policy is managed in the context of the following business and investment principles:

- Private industry, not government, should develop Alberta's mineral resources;
- Open and competitive markets result in the greatest overall benefits;
- The fiscal system should be stable and predictable and reflect the economics of exploration and production over time, across price ranges, pool sizes, and quality differentials;
- Producers are entitled to a competitive return on investment that recognizes all their costs and risks, including the need to maintain the investment necessary for a healthy and sustainable industry; and,
- The people of Alberta, on the same basis, should receive a fair share of the revenue as owners of the resources.

5.0.0.0. Royalty Framework

Alberta's royalty regime is designed to be stable, predictable, transparent for the public and industry, and competitive (in order to facilitate the necessary investment).

The royalty framework incorporates two key economic principles:

1. Economic Rent:
   a. The royalty system is predicated on the expectation that the Crown will collect the economic rent over the full life cycle of the entire resource base. Economic rent is the income remaining after producers recover all costs, including the costs of unsuccessful efforts, investment, innovation, risk, and a competitive return on investment;
   b. Alberta captures economic rent through royalties and bonuses; and,
   c. Royalty programs fine-tune the general royalty framework.
2. Competition:
   a. Open access and integrated North American markets ensure fair prices for Alberta's oil & gas; and,
   b. The bonus bidding system relies on competition, and captures the share of economic rent not captured by royalties.

Figures 1 and 2 illustrate economic rent over the entire resource and for a given pool or well. The upward sloping line in Figure 1 represents the full cost for all of the individual natural gas pools that are available for development. This line is upward sloping to reflect that some resources have higher costs per unit, primarily due to smaller and less attractive pools. Movement along this line from bottom left to top right reflects the higher price that is required to cover the costs to develop these resources. At higher prices, the pools with lower costs enjoy increased net

profits. This illustration also shows the effect of demand conditions that require industry to bring on new supplies; e.g., from the Northern frontiers, and from unconventional sources such as NGC. Since these supplies generally cost more, prices increase to reflect the new cost environment.

Figure 1

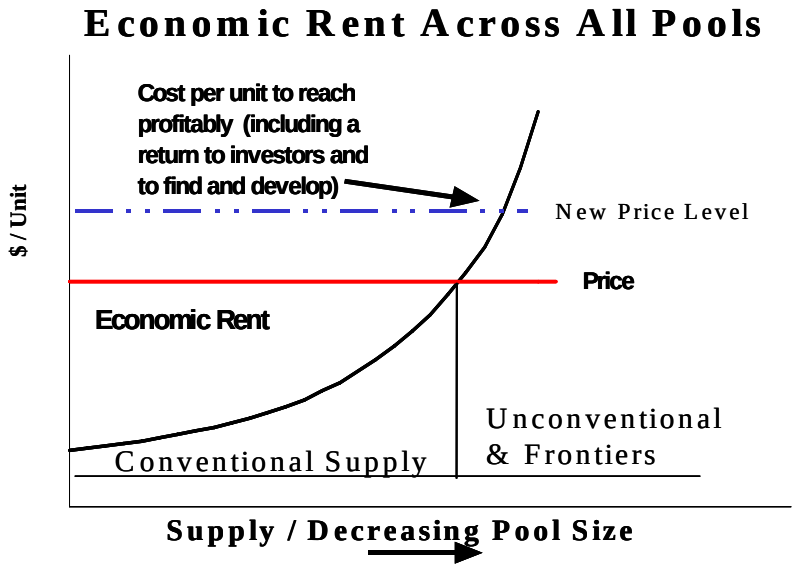
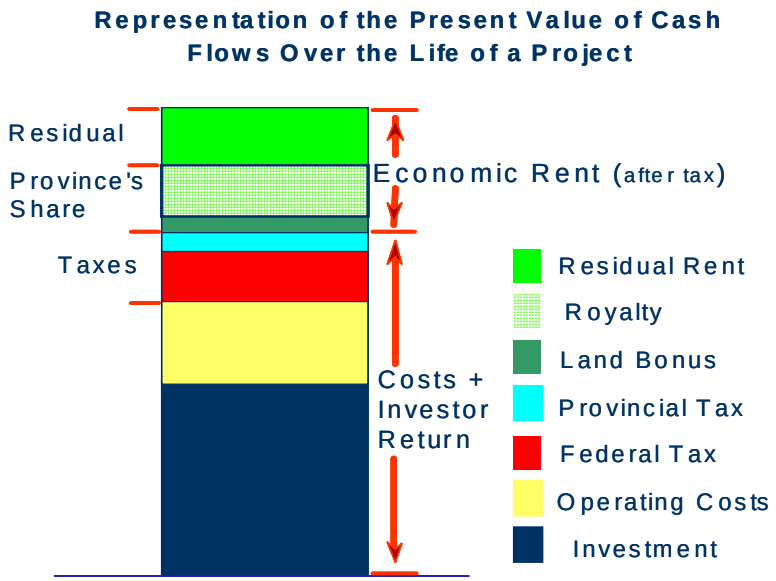


Figure 1 illustrated the situation for the entire resource; it is also instructive to consider the case of a single pool (Figure 2). For any given pool the royalty system may leave some residual rent with industry to account for unforeseen risks and to facilitate industry activity and bidding for subsequent investment opportunities.

Figure 2

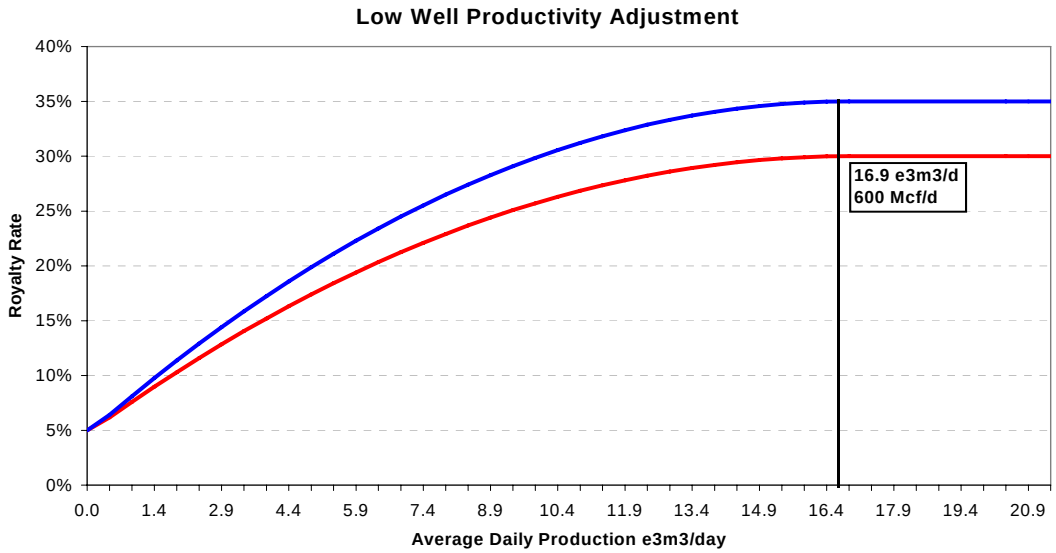


6.0.0.0. Royalty Rates

Figure 3 illustrates the natural gas royalty rate and the associated low well productivity allowance. Alberta's natural gas royalty system is sensitive to a variety of factors:

- It is applied on a well basis;
- It recognizes older, lower cost, resources; Old Gas (pools discovered prior to 1974) are subject to a maximum rate of 35%; the maximum rate for New Gas (pools discovered in 1974 or later) is 30%;
- Royalty calculations are based on the energy content of the natural gas produced – products with higher energy contents such as propane receive a higher price;
- The royalty rate is sensitive to price and to individual well productivity;
- The minimum rates are set at 15% (before tax), however adjustment for low productivity can reduce any of the rates along the curve to 5%; e.g., price alone may indicate a 30% rate however the productivity of the well may determine that this rate be reduced to 5%; and,
- The system also recognizes the costs of gathering, compressing, & processing the Crown's royalty share through a gas cost allowance (GCA) that is calculated on a corporate-wide basis. GCA is not a wellhead cost recovery program; thus cost such as those for drilling and dewatering the reservoir are not eligible.

Figure 3 – Natural Gas Royalty Rates



Further information on the Alberta natural gas royalty system with comparisons to other Canadian jurisdictions can be found on the government's website: www.energy.gov.ab.ca.

7.0.0. Natural Gas in Coal

8.0.0.0. NGC Resource Overview

The Alberta Geological Survey (AGS) estimates that there is potentially about 514 trillion cubic feet (Tcf) of natural gas in coal in place in Alberta. This resource is referred to as unconventional gas because it requires non-traditional technologies or applications of technologies to recover this gas. To place this resource in context, the Alberta Energy and Utilities Board (EUB) estimates Alberta's resource of conventional gas at about 260 Tcf, of which 200 Tcf is thought to be ultimately recoverable. Of the 200 Tcf, 116 Tcf has already been produced, with the remaining 84 Tcf classified as "established" by drilling (40 Tcf) and "yet to be established" (44 Tcf). Therefore, when compared to the conventional resource of 260 Tcf, the NGC resource is huge (about 2-times the conventional resource).

Table 1 below provides a breakdown of the NGC resource by coal zone for both Crown and freehold land. The table shows that roughly 80% of the resource is on Crown land with the remaining 20% on freehold land (Appendix 2 presents a detailed map of the locations of the coal formations listed in Table 1).

Table 1 Alberta's Natural Gas in Coal Resource			
Coal Formations	Total (Tcf)	Crown Land (Tcf)	Freehold Land (Tcf)
Scollard (Ardley)	57	53	3
Belly River	147	107	40
Horseshoe Canyon	71	51	20
Mannville	239	188	51
Total	514	400	114

At this stage, however, caution must be exercised; the AGS does not speculate on the amount of Alberta's NGC gas in place that may ultimately be recoverable and thereby translated into economic value. This is still the early stage of NGC exploration and development. As drilling and analysis continue and more information is obtained it will be possible to provide meaningful estimates of the potential recoverable volumes.

9.0.0.0.General Characteristics of Alberta's NGC Resource

Current development of NGC has been proceeding with 91% of the wells drilled to date in the Horseshoe Canyon coals, 7% in the Mannville coals, and the remaining 2% in the Ardley coal seams. Based on EUB statistics to the end of September 2004, roughly 2,500 NGC wells have been drilled in Alberta, of these about 1,100 had some production.

The two NGC resource plays that have received the most attention to date are the Horseshoe Canyon and the Mannville. Their general characteristics are:

Horseshoe Canyon:

- 91% of wells drilled to date;
- Depth: 200 - 800 metres; and,
- Primarily dry.

Mannville:

- 7% of wells drilled to date;
- Depth: 1000+ metres; and,
- High volumes of saline water.

In addition to the Horseshoe Canyon and the Mannville NGC resource plays, the Scollard (Ardley) coal zone has been identified as having potential for development. To date there has been little activity in the Ardley zone. The Ardley has the following general characteristics:

- 2% of wells drilled to date;

- Depth: 200 – 600 metres, above the Horseshoe Canyon coals;
- Some water, both saline and fresh; and,
- Data and information on the Ardley coals is limited due to the small number of wells drilled into these coals.

See Appendix 2 for a detailed map of stratographic intervals containing coal formations with NGC potential in Alberta.

Alberta's NGC resource has its own unique characteristics that differentiate it from other basins in North America, these include:

- NGC development in Alberta will be aided by the existing infrastructure that has been developed for conventional natural gas production. Pipelines, gas processing plants, and gas field plants already in existence in Alberta are some examples of infrastructure currently employed within the conventional natural gas industry that can be utilized to benefit future unconventional gas development;
- Coal seams found in Alberta are thinner in size than those found in, for example, the Powder River Basin of Wyoming. This is a unique characteristic to Alberta coals that tends to increase the difficulty and costs of recovering this resource;
- Alberta coals have unique characteristics with respect to water content. Horseshoe Canyon coals are predominately dry; i.e., there is little water production associated with natural gas from these coals seams. Mannville coals, however, are for the most part wet, containing saline water. Scollard (Ardley) coals as well are primarily wet largely containing fresh water; and,
- The Mannville coals are estimated to contain 239 of the 514 Tcf (or 46%) of NGC resource in Alberta. Water handling, including disposal is a major consideration in the development of this resource. Inclusion of the other wet coals could bring the total resource for which water handling is a major concern to roughly two-thirds. Further information on water issues and costs typical of Alberta's wet coals is contained in Appendix 3.

1.2 Findings

1.1.1. NGC Third Party Research

A number of reports have been recently published concerning the development of NGC in Alberta. A brief summary of some of these reports is presented below.

- "**Moving Down the Resource Triangle … Uncovering The Value of Coalbed Methane & Other Unconventional Gas Opportunities**", by CIBC World Markets, November 2003.
  - CIBC believes that NGC is an attractive alternative to conventional gas production sources due to economics; low costs and that NGC plays have lower decline rates;

- CIBC estimates that out of the NGC in place, about 14 to 40 Tcf within Alberta is potentially recoverable;
- The largest portion of NGC can be found in the Alberta Plains within the Mannville coals;
- CIBC forecasts that by 2010 Canada will produce 1.4 Bcf/day of NGC;
- The NGC found in the Alberta Plains will be the first developed due to economics and low costs, because of existing gas infrastructure in this area; and,
- CIBC conducted extensive economic analysis on the various coal seams. Horseshoe Canyon appears to be economic at gas prices above $3.50/Mcf. Mannville is economic at prices above $4.50/Mcf because of its water content that results in higher costs.

- "**Coalbed Methane Projection to 2010**", Presentation by Steven Paget, Research Analyst, FirstEnergy Capital Corp. to the Petroleum Services Association of Canada (PSAC) 2005 Canadian Drilling Activity Conference.
  - FirstEnergy states that the development of NGC is similar in size of capital investment to that of an Alberta Oil Sands project. It is forecasted that between 2004 and 2010 that there will be approximately $9 billion in capital investment in NGC within Alberta;
  - FirstEnergy forecasts that NGC production will steadily increase over the decade reaching 1.4 Bcf/day by the end of 2010; and,
  - FirstEnergy also forecasts that annual NGC drilling will increase to 5,400 wells in 2010 (3,500 in Horseshoe Canyon, 1,800 in Mannville and 100 in Ardley).

- "**CBM 101 A Short Course in CBM in Alberta**", by Ross Smith Energy Group, November 2004.
  - 28 operators are currently licensed to drill NGC wells in Alberta;
  - The top 3 operators are: EnCana (502 wells), MGV (351 wells) and Trident (231 wells);
  - About 1,100 wells are producing natural gas from HSC coals;
  - Horseshoe Canyon (HSC) coals are commercial i.e. viable; and,
  - The commercial viability of Mannville NGC development is yet to be determined.

- "**Short-term Canadian Natural Gas Deliverability 2004-2006**", by The National Energy Board (NEB), November 2004.
  - The NEB publishes annually an energy market assessment that forecasts natural gas deliverability for Canada, this year's report includes NGC forecasts for the first time;
  - The NEB estimates that NGC will become an increasing component to Western Canadian Sedimentary Basin (WCSB) natural gas production. Currently NGC is less than 1% of total WCSB gas production; by the end of 2006 NGC's share is predicted to increase to 5%;
  - The NEB states that their forecast is for Horseshoe Canyon gas production only. Mannville coals are not considered at this time as they have yet to be proven economically commercial;

- The NEB estimates that about 750 NGC wells will be connected in 2004, 1,400 in 2005 and 1,800 in 2006; and,
- These new wells will increase NGC production from the current level of 100 MMcf/day (mid-2004) to 450 MMcf/day by the end of 2006.

- "**COALBED METHANE – A Significant Gas Supply from Western Canada?",** by Ziff Energy Group, December 2004.
  - [NGC] (CBM) production in Alberta, Canada should exit 2004 at 100 MMcf/d with all production from the generally dry coals of the Horseshoe Canyon.
  - Gas-in-place reserves for the Horseshoe Canyon are estimated at 66 Tcf; economically recoverable reserves are at 10 to 15%.
  - Mannville gas-in-place reserves are estimated at 320 Tcf but economically recoverable reserves are only 1 to 4%.
  - Other CBM horizons include the Ardley and Belly River coals. Little CBM production is expected from the other CBM horizons over the outlook period.
  - Ziff Energy's assessment:
    - CBM production grows to 0.4 Bcf/d by 2006 and triples by 2010
    - If Canadian CBM production were to follow the same production profile as the U.S. CBM, Canadian CBM production would grow to 1 Bcf/d by 2006 and 2.6 Bcf/d by 2010 [total current Alberta natural gas production is about 15 Bcf/d]
    - While there is no current CBM production from the Mannville coals, there is significant upside to the Canadian CBM production forecast if economic producing techniques (including water disposal solutions) are developed. Ziff Energy estimates the additional upside at 0.1 Bcf/d in 2006 and 0.3 Bcf/d in 2010.
    - The issues facing the CBM industry include: ownership of freehold leases, need for land consolidation and access, water disposal techniques, and unnecessary regulatory oversight.

1.1.2. RWG/ADOE Economics Analysis (2003 – 2004)

1.1.2.1. Economic Analysis Methodology and Assumptions

The task of conducting and completing the economic analysis for the working group was taken on by the Department of Energy with guidance and support from industry members of the working group. The model used is the Value Navigator Software [2].

The RWG collected data, examined and analyzed only the Horseshoe Canyon and Mannville coal seams since these coal seams are considered to have the potential for significant levels of production in the foreseeable future. Scollard (Ardley) coals were not analyzed due to the limited information on these zones. To date little activity has been done in the Scollard (Ardley) coal zone primarily because of the fresh water that is present in these coals.

The general approach was to compare NGC data on a net present value (NPV) basis for both the Horseshoe Canyon and Mannville to conventional developments with similar pool size and drilling depth characteristics.

Both Horseshoe Canyon and Mannville have their own distinct characteristics as reflected in the applicable natural gas price, production profiles, and the associated capital and operating costs.

- Prices: While NGC production is "dry" – meaning it has very little liquids content – and therefore cannot command a premium based on energy content, this analysis compares with "dry" conventional production so the price was held the same;
- Production: NGC production from a given well can be described as starting later and reaching a lower maximum rate (particularly relevant for "wet" coals), but with a lower decline rate than conventional production. Typical production profiles and comparisons are illustrated in Appendices 6 to 9. Attention is drawn to the Mannville production profiles as these coals are characterized as "wet", thereby causing operators to have to manage associated water production. Because of the need to de-water, gas production from these coals experiences a delay not characteristic of dry coals or conventional gas developments; and,
- Capital and Operating Costs: Horseshoe Canyon and other NGC developments may ultimately benefit from economies of scale associated with efficiencies gained through generally larger drilling programs; however, for this analysis Horseshoe Canyon costs are assumed to be the same as those for conventional developments. Because of the need to produce, handle, and dispose of water this assumption is not appropriate for the Manville developments where costs are anticipated to be higher than those for conventional gas. Appendix 4 provides a summary of the cost assumptions.

Based on the input parameters the following results are calculated to provide a basis for comparison:

- Gross revenue (gas production multiplied by the price);
- Capital and operating costs (as per input parameters);
- Federal and Alberta corporate income tax;
- Alberta natural gas royalties (based on the current "New Gas" royalty formula);
- Before Tax NPV (the discounted net revenue, this is the discounted value of gross revenue less all costs but not taxes and royalties);
- After Tax NPV (before tax NPV less federal and provincial corporate income tax); and,
- After Tax & Royalty NPV (after tax NPV less royalties - this is equivalent to the profit remaining for the company).

A summary of the net cash flows for Horseshoe Canyon and Mannville can be found in Appendix 10.

1.1.2.2. Economic Analysis and Results

1.1.2.2.1. Horseshoe Canyon

Background

Natural gas found in coal seams is no different, in composition, than natural gas from other conventional sources. In fact, the gas produced from a HSC well has a higher methane composition than conventional gas sources at similar depths.
It has been found that the average daily rates of production from HSC well is approximately 100 Mcf/day and that it declines slowly over time with production expected to continue for 20 to 40 years. These low rates of production qualify these wells for the low well productivity allowances already built into Alberta's gas royalty framework.

Analysis

The economic analysis for the Horseshoe Canyon (HSC) coals was completed based on the following input variables:

- The costs applied to the economic model are summarized in appendix 4.A. The NGC costs include actual and proforma information gathered from industry, the conventional costs are for Southeast Alberta and based on CAPP and ADOE data.
- The gas prices can be found in Appendix 5. The working group employed a price of $5.10/Mcf (in real/constant terms). Note that the HSC economics were not completed for the higher $6.20/Mcf price case since the lower case continually resulted in positive NPVs, thus the working group concluded that economics were positive and the royalty system was working appropriately for the HSC coals;
- HSC gas production profiles are shown in Appendix 6; here alternative NGC cases are compared to a conventional southeast Alberta gas well. This graph is typical of NGC wells, it illustrates that they peak at lower rates than comparable sized conventional pools, however they are shown to produce for a far longer period of time;
- Throughout the analysis NGC wells were compared to conventional gas wells of similar size. The group felt that this is useful as it establishes a point of comparison of the development of the relatively new NGC resource to our existing knowledge;
- Since HSC wells produce only small quantities of water, water costs beyond those faced by conventional gas wells were not considered;
- The economic analysis shows the Horseshoe Canyon to be economically viable (see Appendix 11);
- Sensitivity analysis (see Appendix 12A) showed all NPVs were found to be positive unless either price or production falls by more than 50%, thereby indicating reasonably robust economics; and
- These economic results are confirmed by other research already referenced and cohobated by the current level of industry activity and development that is ongoing in the Horseshoe Canyon.

1.1.2.2.2. Mannville

Background

The Mannville and other wet coal seams contain 60% of Alberta's NGC potential. Although exploration and pilot projects into the Mannville coals began at roughly similar times as those in the Horseshoe Canyon, there is currently much less drilling in the Mannville coals. Due to the water content of the Mannville coals their gas production rates are highly variable. Discussions with industry found that the low initial rates of gas production can be attributed to the amounts of water in the coal seams. Poor permeability in the Mannville coals also explains low gas rates throughout the project life. The need to dewater the coals leads to high initial cost with little revenue during the exploration and pilot phases of the program. It is expected that once the play has been dewatered, production will increase. Mannville NGC projects have yet to move to the commercial stage. Current production from pilot Mannville projects has found the average daily rates of production to be about 50 to 200 Mcf/day. Current estimates suggest that a Mannville well may be able to average between 300 - 600 Mcf/day, at peak production. Here, too, the low well productivity allowance contained in the current gas royalty formula is a benefit, reducing the royalty rate as production falls below 600 Mcf/day.

The key defining characteristic for the economics of Mannville NGC is salt water, as this ultimately determines both gas production and costs. Associated questions are how much water, how long will the dewatering phase take before sufficient quantities of natural gas can be produced, and what technological improvements will be made that may improve this situation?

One innovative option for development of Mannville coals is horizontal drilling. This technology generally costs more than conventional vertical well drilling; however it offers the potential to significantly increase NGC well productivity. Concern has been expressed that current low well productivity adjustments may need to be modified to accommodate production volumes from horizontal NGC wells. The combined effects of higher drilling costs and potential increased production volumes have not yet been determined for this technology.

In recognition of the need for more innovation directed toward Alberta's oil and gas resources the Alberta Department of Energy announced the Innovative Energy Technology Program (IETP) in June 2004. This program is designed to accelerate implementation of new technologies that enhance Alberta's competitiveness in world markets and ensure our continued economic prosperity through environmentally responsible development of conventional oil, in situ oil sands, and natural gas resources. This program provides up to $200 million in royalty adjustments (over the next five years); of this amount, one can expect a

significant portion to be allocated for natural gas research, depending on the attractiveness of the proposals received.

Analysis

The economic analysis for the Mannville coals was completed based on the following input variables:

- There is a large degree of uncertainty with regard to the costs associated with the Mannville coals, with actual costs from pilot developments varying beyond expectations; this is highlighted in Appendix 4. The costs applied to the economic model are summarized in Appendix 4B. The NGC costs include actual and proforma information gathered from industry, the conventional costs are for Central Alberta and based on CAPP and ADOE data;
- The gas price assumptions used in the Mannville analysis are the same as those for the HSC analysis and can be found in Appendix 5.
- Mannville gas production profiles are shown in Appendix 7 to 9. Appendix 9 displays the base case water and gas production profiles that were assumed for Mannville coal seams;
- Appendix 7 summarizes the natural gas production for two alternative NGC Mannville cases and compares their profile with that of a conventional gas well of similar size in central Alberta. Both lower and higher Mannville cases were evaluated and their economics compared to the conventional gas case; and,
- Appendix 8 summarizes alternative water production profiles that were employed in the economic analysis. All three water profiles were evaluated. Economic results varied by scenario; no conclusion could be reached on the economic viability.

- **Economic Comparison NGC Mannville to Conventional Well:**
    - Mannville cash flow diagrams are summarized in Appendix 10. These diagrams show that wet coal development takes significantly longer to recover investment, indicating that this is an issue that could hamper development of Mannville and other wet coals;
    - The economic analysis first compared an NGC well to a conventional gas well of similar size (see Appendix 11); the conventional well was found to have a higher NPV. This is due to two reasons. First, conventional gas wells produce the gas quicker and therefore revenues are higher in earlier years. Second, conventional wells are not characterized by dewatering at the start of their production lives. Wet NGC wells require a dewatering stage that results in upfront water handling costs associated with little to no gas production. This delays cash inflows whereas conventional gas wells start producing and reach positive cumulative cash flows faster; and,

  - The presence of water, the uncertainty and risk relating to its amount, and the costs of water disposal have resulted in an economic picture for wet NGC that is highly uncertain.

- **Mannville Economic Sensitivity Analysis:**
  - Further analysis of Mannville economics considered variations in price, capital cost, operating cost, water disposal costs and production; these results are found in Appendix 12B to 12D;
  - The results illustrate that there is no clear-cut economic outcome for the Mannville coals.
  - Outcomes vary and are dependent not only on the costs, price, and production levels, but also on the water to gas ratio; and,
  - Economic results for the Mannville coals reiterates the importance of water production and its disposal costs to the profitability of wet coals in Alberta.

Summary

- The economic analysis completed by the Department of Energy for the working group evaluated a large number of scenarios for a Mannville project. Many of the input variables such as, price, production, and costs were varied within ranges thought to be reasonable. The resulting economic picture is highly uncertain; the NPV results ranged from positive to negative as shown is Appendix 11 and 12;
- These results are determined by the need to identify and apply the appropriate technology to extract the gas and by the costs of handling and disposing of large volumes of associated water;
- Given the potential size of the NGC resource and the anticipated future decline in conventional natural gas resources, the RWG recognizes the need for the Alberta Government to consider whether to encourage responsible NGC development. Examples of where Alberta Government leadership in the past resulted in the successful development of the province's resources include the oil sands and deep gas.
- The RWG also raised the fact that in the United States, early NGC development was assisted by a credit against federal income tax. In this context, it was pointed out that NGC is not unique to Alberta, and therefore, if assistance is needed, Alberta's royalties should not have to shoulder the entire burden. Other provinces with NGC potential include British Columbia, Saskatchewan, Ontario, and Nova Scotia. British Columbia has already implemented a program to encourage NGC development. Alberta currently has the most active investment in NGC.
- BC announced changes to their royalty and tax regulations for NGC are summarized in Appendix 13.
- Lead by industry, the RWG identified several possible ways to assist with the costs of water handling; these are presented in Appendix 3. Given the uncertainty with Mannville economics, the group agreed that no permanent change to the royalty structure could be recommended at this time; and,

- Without a better understanding of the resource and the impacts of the changes on the actual economics for wet coals, the identified potential royalty options to account for the water handling and disposal costs were not examined in detail by the working group at this time.
- As previously noted and referenced in Appendix 3, industry representatives identified a number of options that government may wish to consider in addressing the identified higher costs of wet coal NGC development in Alberta. These options are:
    - Provide a royalty credit for NGC wells that have water disposal costs;
    - Allow water disposal costs as a gas cost allowance (GCA) deductible cost;
    - Allow for a separate gas plant type for NGC wells;
    - Provide a royalty holiday for horizontal NGC wells;
    - Increase the allowable rate of return for NGC gathering systems and compression capital costs;
    - Provide a royalty credit or some form of assistance for deep re-injection of water;
    - Lower the royalty rate for NGC production; and,
    - Implement a royalty system similar to that found in the oil sands industry – a revenue minus cost (R minus C) royalty regime for NGC;
    - Introduce a sliding scale component to the royalty rate, similar to the low well productivity allowance, that is a function of the water/gas ratio.
- ADOE officials on the RWG acknowledged that these options are useful as examples of possible approaches that may be necessary as more information is obtained. This said, officials did comment that the R minus C option does not seem to be applicable to the characteristics of Alberta's NGC resource;
- For the reasons already stated, these options were not considered further at this time; and,
- All of these options and others will be considered if it is determined that some form of short-term program for NGC is needed and, following this, if a long-term solution proves necessary.

- Changes to Crown royalties will not impact freehold properties; this is another reason why industry's concerns can also be assisted through specific recognition of NGC in the federal and provincial income tax formula.
- In order to learn more about Mannville coal seams and wells, it will be necessary to drill not just wells but groups of wells together in pilot programs. Single exploratory wells or wells drilled to hold lands will not shed much light on the relative economics of Mannville NGC.

1.1.3. Conclusions

- Horseshoe Canyon dry coal development has been shown to be commercially viable;

- Mannville economic results are not conclusive; there is no clear-cut determination that this NGC play is or is not economically viable based on our current level of understanding. Drilling activity clearly shows that industry has not pursued development of the Mannville as aggressively as the Horseshoe Canyon;

- The most significant variables in determining the economic outcome in the Mannville coals are price, gas and water production, water to gas ratio, and water disposal costs. With price determined by the market place and the royalty formula already sensitive to price, it appears at this stage that water handling and disposal are the key issues that need further investigation.

- The economic results of wet coals indicate that these NGC projects may not be economically viable under current conditions. This puts an estimated two-thirds of the NGC resource at risk of not being developed.

1.1.4. Recommendations

- *The ADOE should consider some form of short-term royalty program immediately to facilitate drilling more wells in order to acquire better knowledge of the wet-coal resource. The objective of this program, which may or may not be continued beyond the early evaluation phase of the resource development, would be to increase the information about these types of coal seams and allow for better assessment of their economic viability as soon as possible.*

- *Alberta and Federal Canadian governments should consider specifically recognizing Canada's NGC potential through their respective corporate income tax formulas.*

PART TWO: Summary of Recommendations

Issue	Outcomes	Recommendations
Is Alberta's present natural gas royalty regime appropriate for existing and anticipated future development of natural gas from coal (NGC)?	• Increased natural gas prices have assisted the commercial development of natural gas in coal. • Horseshoe Canyon dry coal development has been shown to be commercially viable. • Mannville economic results are not conclusive; there is no clear determination that this NGC play is or is not economically viable based on the current level of understanding. Drilling activity clearly shows that industry has not pursued development of the Mannville as aggressively as the Horseshoe Canyon; • The most significant variables in determining the economic outcome of the Mannville and other "wet" coal development prospects are price, gas and water production, water to gas ratio, and water disposal costs. With price determined by the market place and the royalty formula already sensitive to price, it appears at this stage that water handling and disposal are the key issues that need further investigation.	• *The ADOE should consider some form of short-term royalty program immediately to facilitate drilling more wells in order to acquire better knowledge of the wet-coal resource. The objective of this program, which may or may not be continued beyond the early evaluation phase of the resource development, would be to increase the information about these types of coal seams and allow for better assessment of their economic viability as soon as possible.* • *Alberta and Federal Canadian governments should consider specifically recognizing Canada's NGC potential through their respective corporate income tax formulas.*

Appendix 1
Working Group Membership

Alberta Department of Energy (ADOE) - Chair
- Barry Rodgers, A/Business Unit Leader, Gas Development
- Matthew Foss, A/Director, Gas Development - Business Analysis
- Richard Stokl, Economist, Gas Development - Business Analysis
- Sharla Rauschning, Director, Gas Operations Policy
- Roger Delbaere, Petroleum Engineering Consultant, Geology
- Bob Nichol, Petroleum Engineering Consultant, Geology

Alberta Energy and Utilities Board (AEUB)
- Georgette Habib
- Bob Willard

Alberta Association of Municipal Districts & Counties (AAMDC)
- Kim Heyman

Anadarko Canada
- Gerard Iannattone
- Travis Tweit
- Lee Wahl

Canadian Association of Petroleum Producers (CAPP)
- David Daly
- David Kopperson

Canadian Society for Unconventional Gas (CSUG)
- Mike Gatens
- Kin Chow

EnCana Corporation
- Chris Johnston
- Marianne Metez

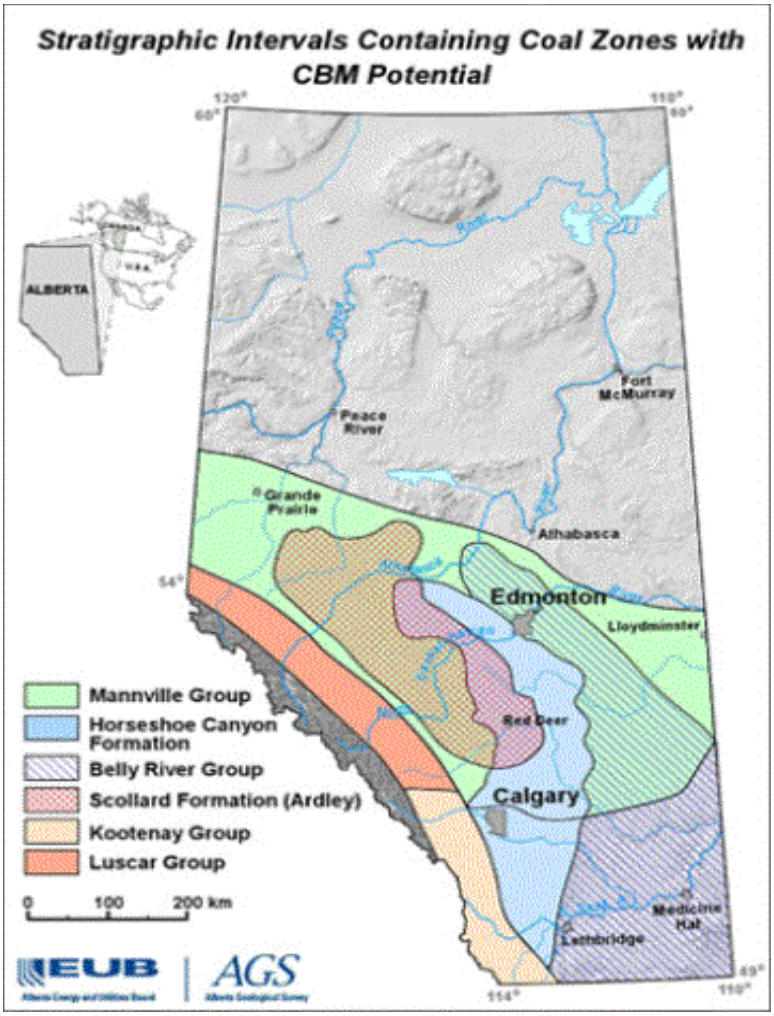
Freehold Owners Association (FHOA)
- Brad Murray

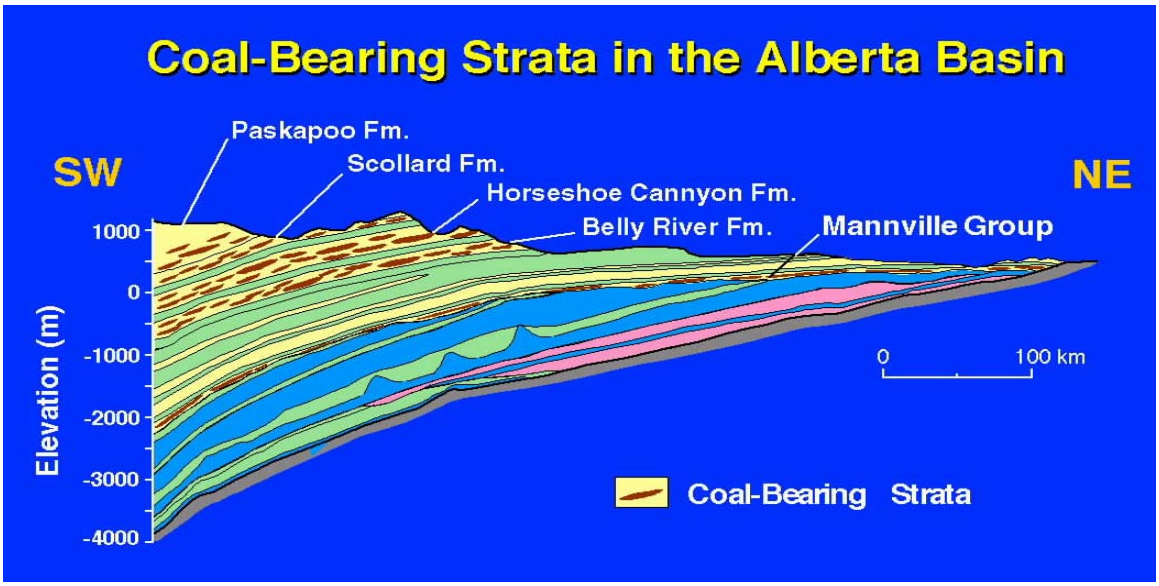
Luscar Corporation
- Yasmin Adamson

Small Explorers and Producers of Canada (SEPAC)
- George Fink

Trident Exploration Corporation
- Kevin Heffernan
- Sandy Murphy

Appendix 2
Location of Alberta's NGC Resource





Appendix 3
NGC Water Issues

A characteristic of NGC is that the methane is adsorbed to the coal. To facilitate production, the pressure within the coal seam must be reduced to allow the methane to detach from the coal. Typically this has been accomplished by removing the water that is resident within the coal seam. Alberta coals exhibit a range of water saturations; the Scollard (Ardley) formation has saline and fresh/potable water, the Horseshoe Canyon formations have little to no water, and the Mannville has high saline water saturations. The initial phase of dewatering is characterized by large amounts of water production associated with little to no natural gas production. Over time as reservoir pressure is reduced the coals will produce less water, this reduced pressure frees the natural gas that is attached to the coal and results in increased gas production. Eventually, it is anticipated that gas production may increase to commercial volumes.

The obstacle of dewatering can substantially increase the costs including:

- Capital and operating costs related to water pumping and disposal;
- Capital costs to drill a water disposal well;
- Fixed and variable operating cost to maintain the water disposal well; and,
- Piping and trucking costs for movement of water from the gas well to the water disposal well.

Industry members of the RWG offered the following suggestions to help offset the costs of water handling:

- Provide a royalty credit for NGC wells that have water disposal costs;
- Allow water disposal costs as a gas cost allowance (GCA) deductible cost;
- Allow for a separate gas plant type for NGC wells;
- Provide a royalty holiday for horizontal NGC wells;
- Increase the allowable rate of return for NGC gathering systems and compression capital costs;
- Provide a royalty credit or some form of assistance for deep re-injection of water;
- Lower the royalty rate for NGC production; and,
- Implement revenue minus cost (R minus C) royalty system similar to that found in the oil sands.
- Introduce a sliding scale component to the royalty rate; similar to the low well productivity allowance that is a function of the water/gas ratio.

The royalty working-group did not pursue the detailed discussions on the form or content of alternative proposals to address issues around water handling costs. The working group instead focused on identifying the uncertainty and risk related to a Mannville NGC projects at this time. These centered on the lack of experience and good data on the water production profiles that typify wet NGC projects such as those of the Mannville coals. The working group agreed that once a better understanding of the uncertainty is obtained it would be reasonable to discuss whether permanent changes to the royalty system are required, and if so what those changes might look like.

Appendix 4
Cost Parameters

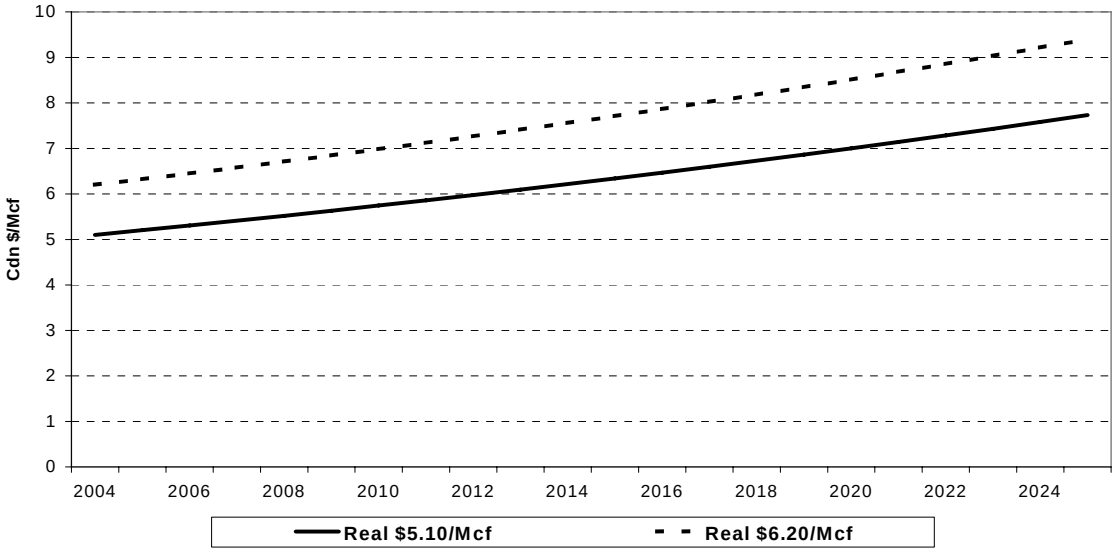
Commentary:

- The tables below summarize the capital and operating costs data provide by industry to the ADOE.
- The costs identified were incorporated in the economic analysis completed by the ADOE for the royalty working-group.
- The data recorded does not reflect the full range for costs that was received during the review. Survey results found that costs (particularly for the Mannville coals) are at present highly variable; e.g.,
    - The monthly fixed gas well operating cost ranged from $2,000 to $22,000 per month over the first year of production.
    - The monthly gas well variable operating costs ranged from $0.50 to $8.00/Mcf over the first year of production.
    - The monthly water disposal costs ranged from $0.10 to $2.50/barrel over the first year of production.
    - Drilling and completion costs ranged from $500,000 to $1,000,000.
- The high variability in costs experienced is ultimately attributed to the lack of current information and understanding of the Mannville and other “wet” coals potential
- These highly variable costs reflect the uncertainty that is currently associated with wet coal development in Alberta.

Appendix 4A. Input Parameters - Horseshoe Canyon Cost Summary			
	HSC Survey - Estimate 2002	HSC Survey - Data 2004	Conventional Southeast Alberta 2004
Capital Costs			
Exploration Drilling & Completion (Thousand Cdn$/well)	555 - 570	420 - 520	200
Development Drilling & Completion (Thousand Cdn$/well)	217 - 226	210 – 310	200
Operating Costs			
Fixed Gas well (Cdn$/well/month)	600	600	1,090
Total Variable Gas (Cdn$/Mcf)	0.56	0.51	0.90
Water Disposal Cost (Cdn$/bbl)	Included in variable well operating expense		

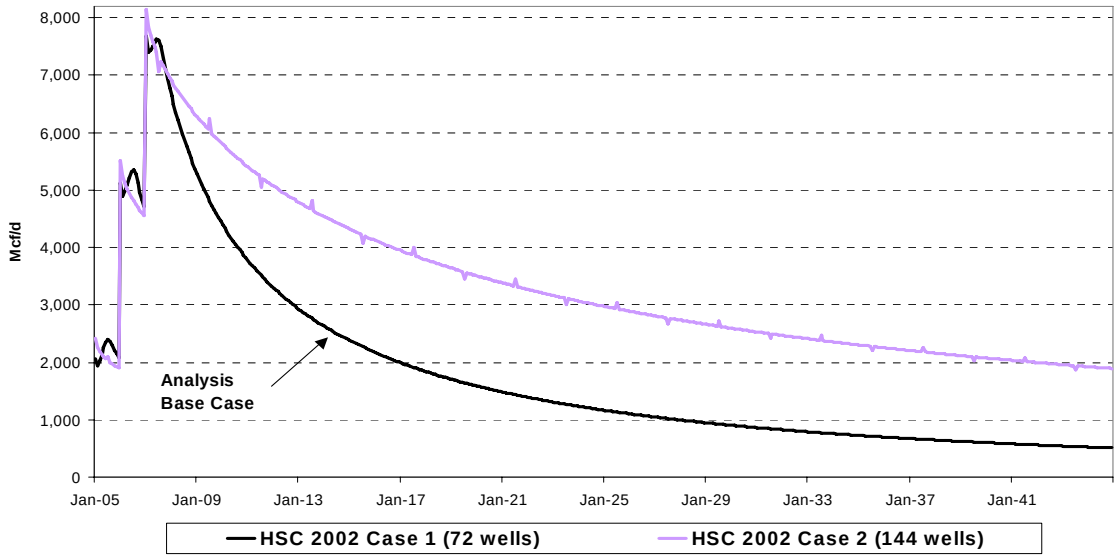
Appendix 4B. Input Parameters - Mannville Cost Summary				
	Mannville			Conventional Central Alberta 2004
	Survey Estimate 2002	Survey Data May 2004	Survey Estimate October 2004	
Capital Costs				
Exploration Drilling & Completion (Thousand Cdn$/well)	770	800	540 (+$34,000/gas well for 16 additional water disposal wells)	300
Development Drilling & Completion (Thousand Cdn$/well)	429	Range: 500 – 1,000		300
Operating Costs				
Fixed Gas well (Cdn$/well/month)	3,000	3,125	2,700	1,197
Total Variable Gas (Cdn$/Mcf)	0.57	5.32	0.25	0.97
Water Disposal Cost Cdn$/bbl	0.50	0.45	1.00	Included in variable well operating expense

Appendix 5
Natural Gas Prices

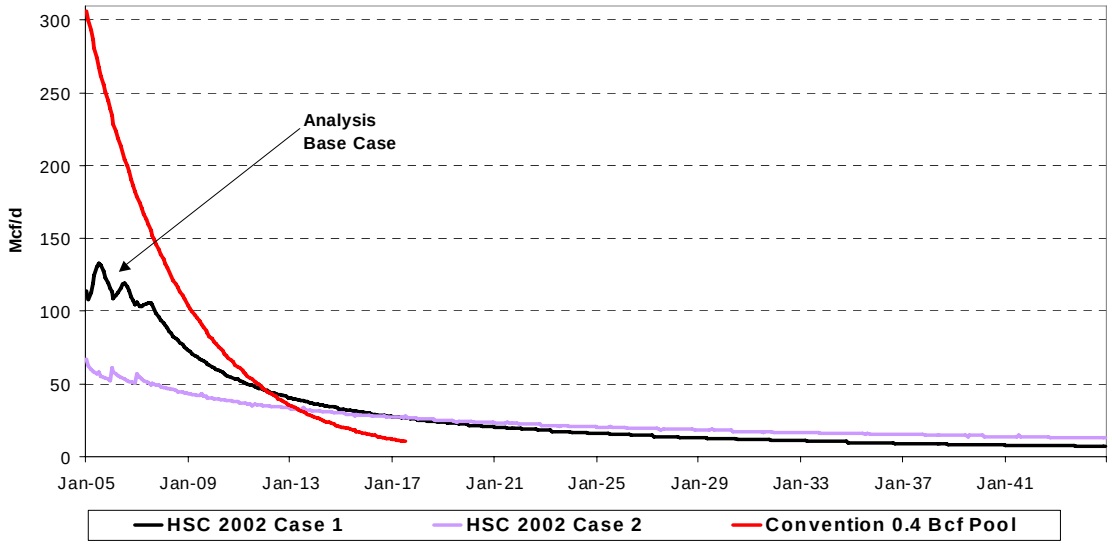


Appendix 6
Horseshoe Canyon (HSC) Natural Gas Production Profiles

6A. HSC Natural Gas Project Production Profiles – Daily Rates

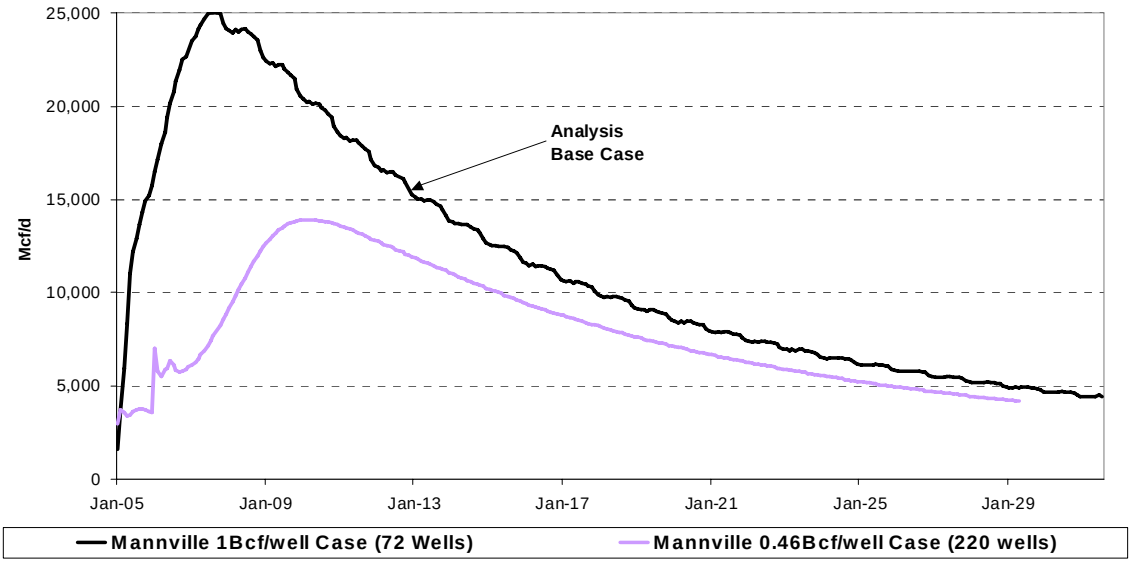


6B. HSC "Average" Single Well Natural Gas Production Profiles

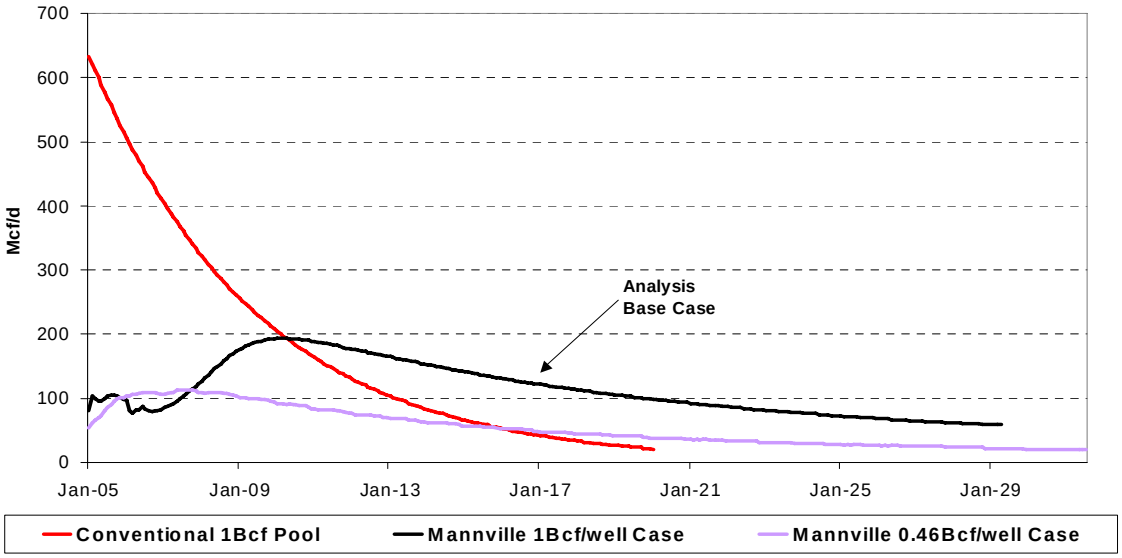


Appendix 7
Mannville Natural Gas Production Profiles

7A. Mannville Natural Gas Project Production Profiles – Daily Rates

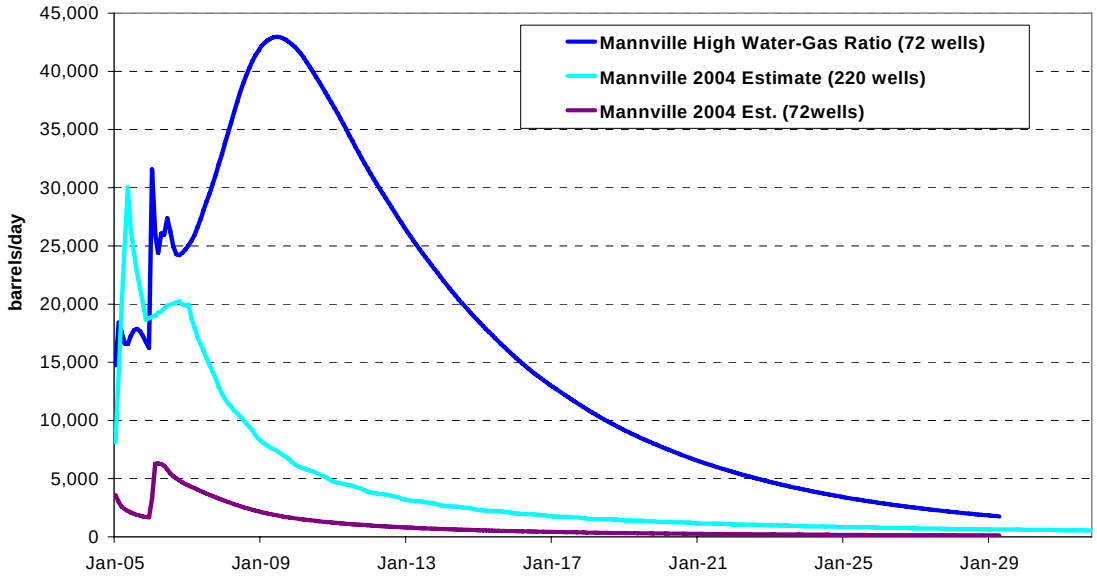


7B. Mannville "Average" Single Well Natural Gas Production Profiles

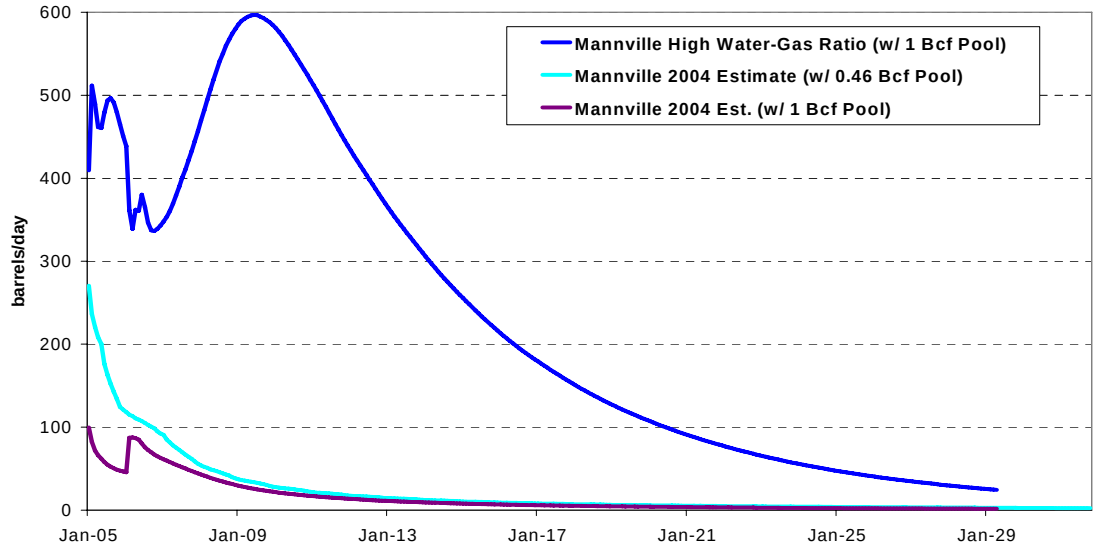


Appendix 8
Mannville Water Production Profiles

8A. Mannville Project Water Production Profiles

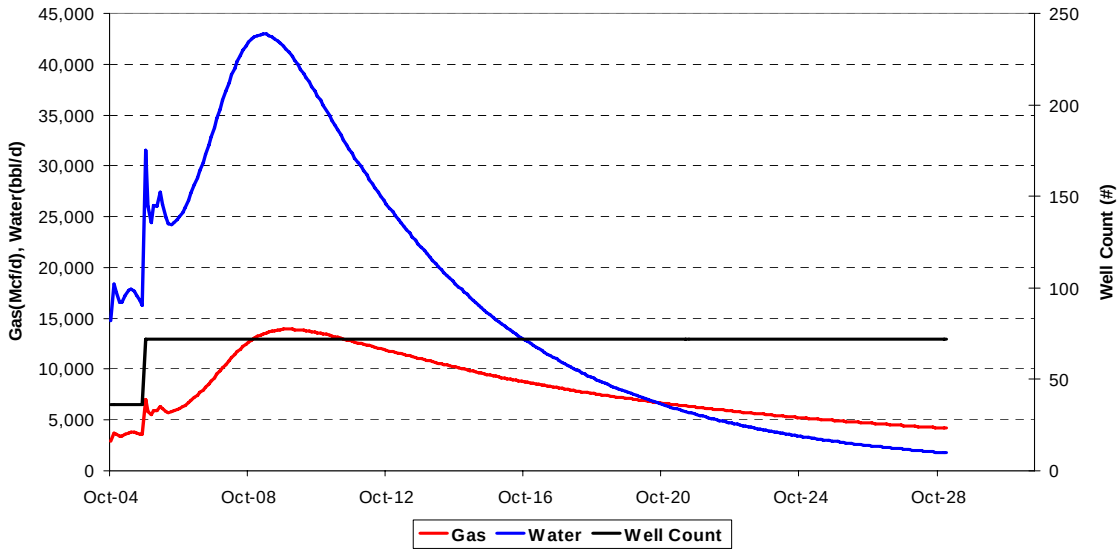


8B. Mannville "Average" Single Gas Well Water Production Profile

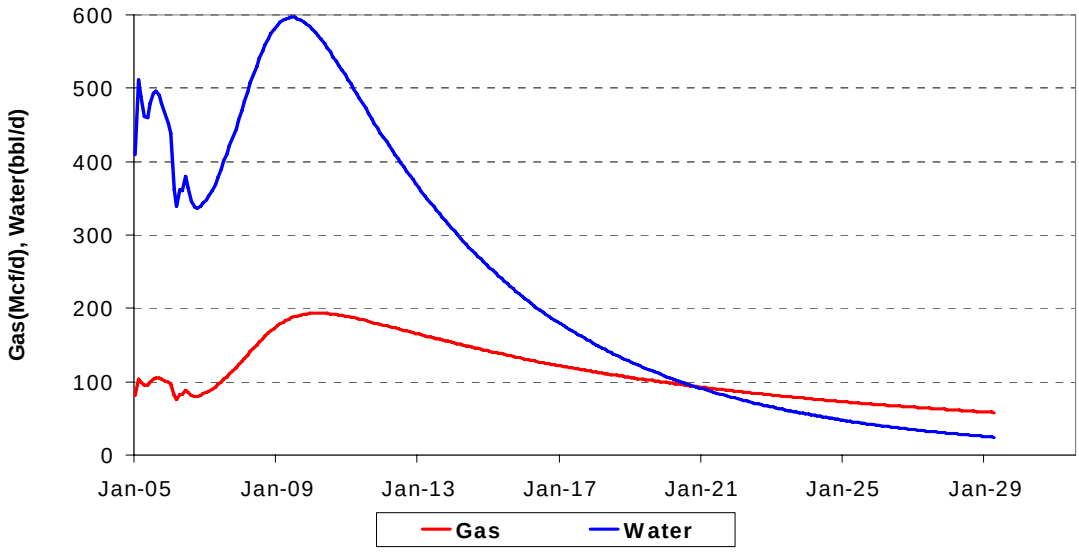


Appendix 9
Mannville Base Case Natural Gas & Water Production Profile

9A. Mannville Base Case Project Production Profiles – Daily Rates, 72 Wells



9B. Mannville Base Case "Average" Single Well Production Profile



Appendix 10
Cash Flow Diagrams

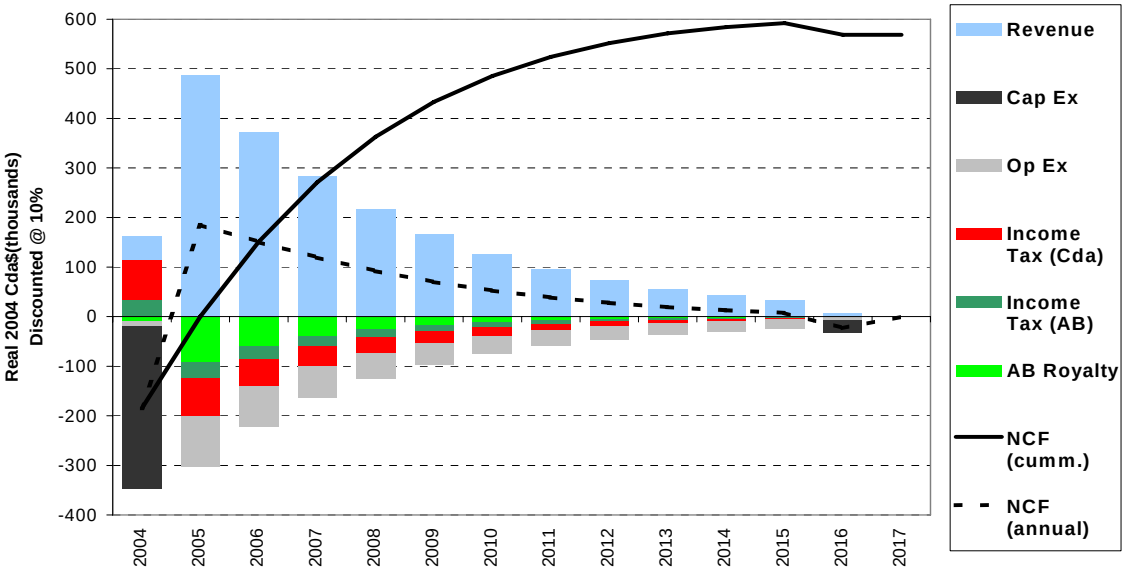
The following diagrams summarize the flows for revenues and costs that might be experienced by a NGC developer over the life of a project. The cash flow diagrams assume a fully taxable (full credit) cash flow position. Full credit economics accounts for taxes on a corporate wide basis. Thus an individual project would be able to write-off costs from one project against revenue from another. This situation is more reflective of normal operations.

Summary of cash flows presented in the following diagrams:

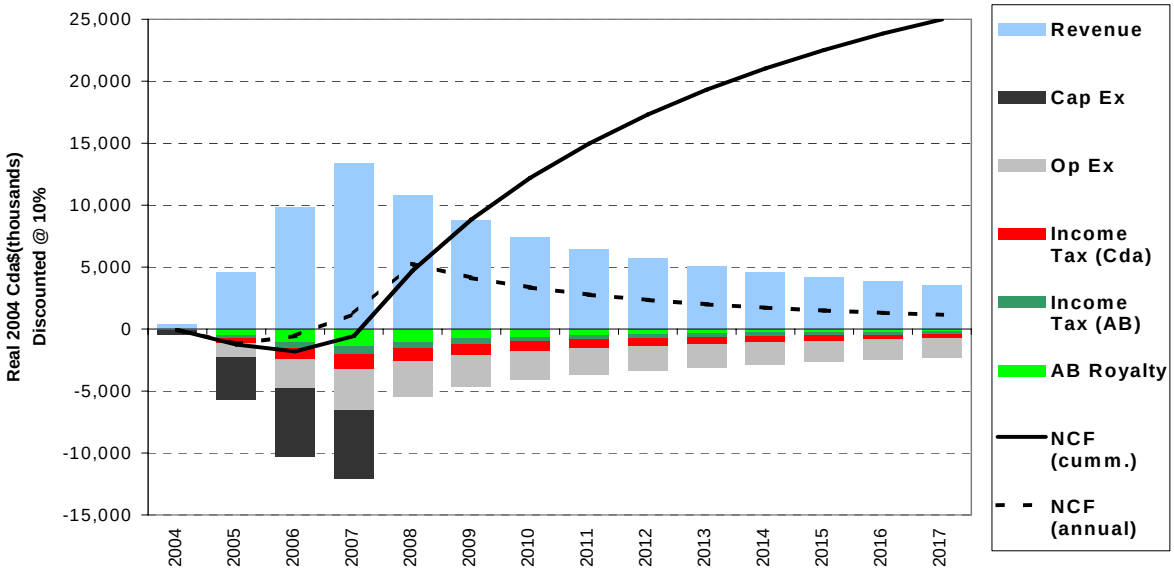
1. Revenue: is the gross revenue collected before all costs, taxes, and royalties, the product of price and production;
2. Cap Ex: is the capital expenditures, e.g. exploration and development drilling costs;
3. Op Ex: is the operating costs, for example the variable and fixed gas well operating costs and the water disposal costs;
4. Income Tax (Cdn): income tax payable to the government of Canada;
5. Income Tax (AB): income tax payable to the government of Alberta;
6. AB Royalty: Alberta natural gas royalty amount owed to the Crown;
7. NCF (annual): The net cash flow in the specified year, it is revenue less capital costs operating costs, income taxes (both Canada and Alberta), and royalty; and,
8. NCF (cumm.): The cumulative net cash flow.

10A. Cash Flow Diagrams

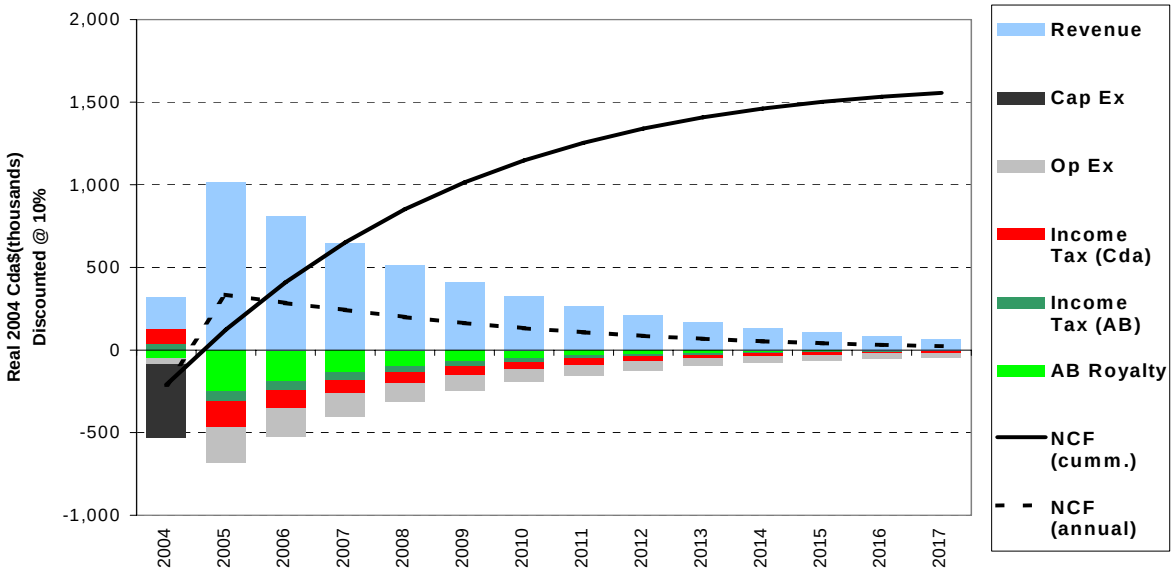
10A.1. Full Credit - Conventional Well – 0.4 Bcf Pool, Single Well Project



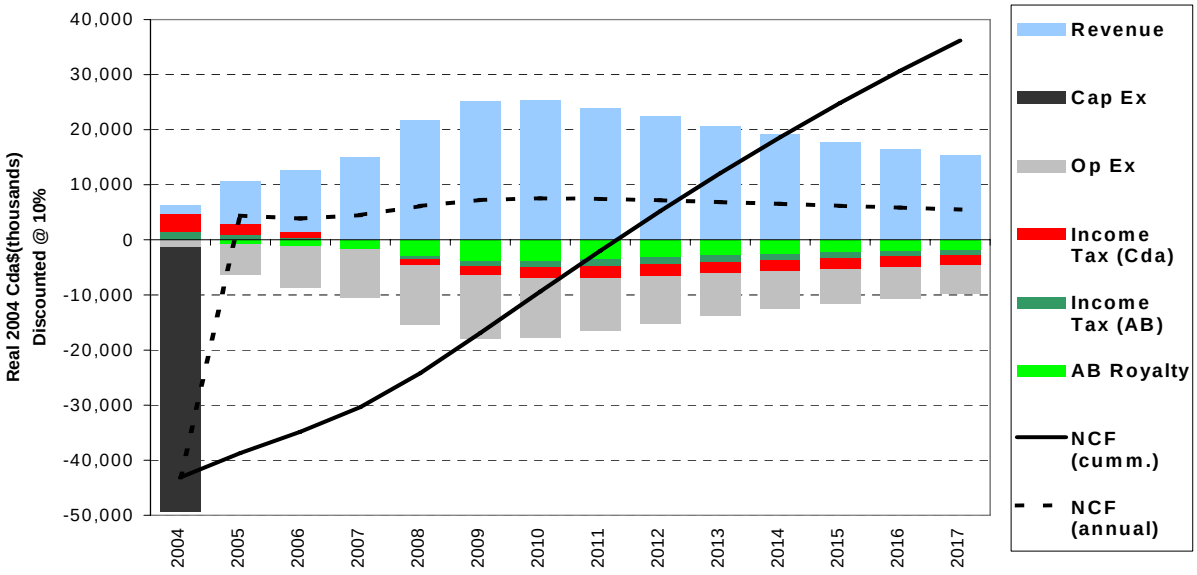
10A.2. Full Credit - NGC – Horseshoe Canyon, 72 Well Project



10A.3. Full Credit - Conventional Well – 1 Bcf Pool, Single Well Project

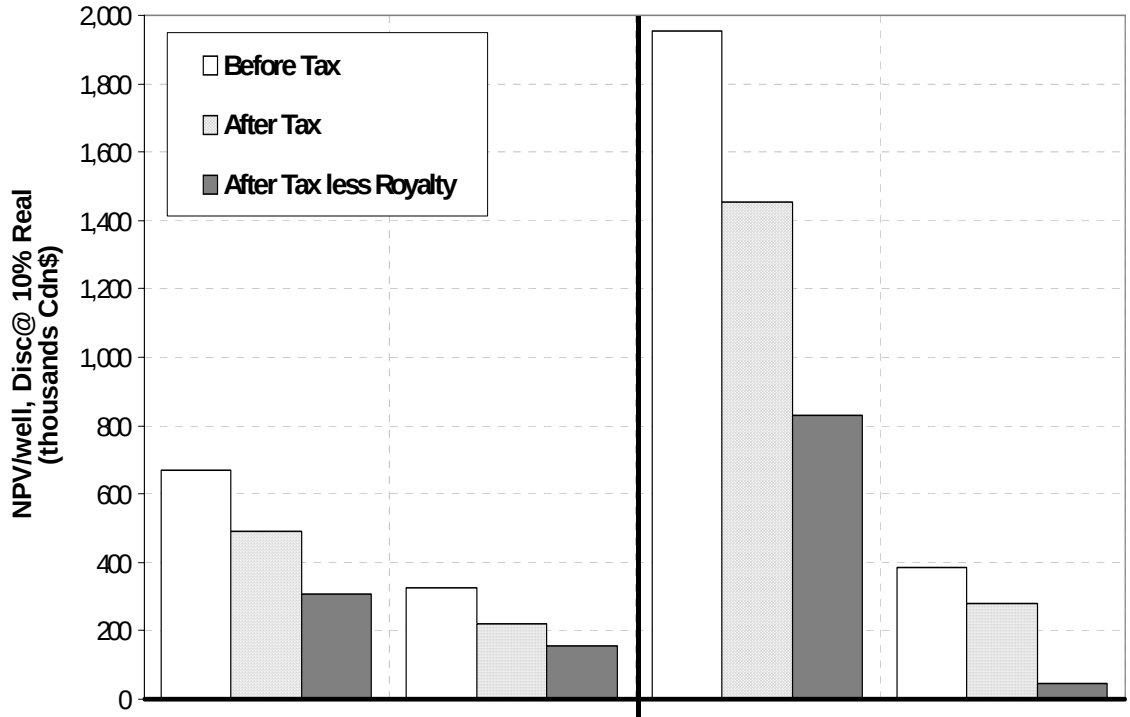


10A.4. Full Credit - NGC – Mannville, 72 Well Project



Appendix 11
Economics Comparisons

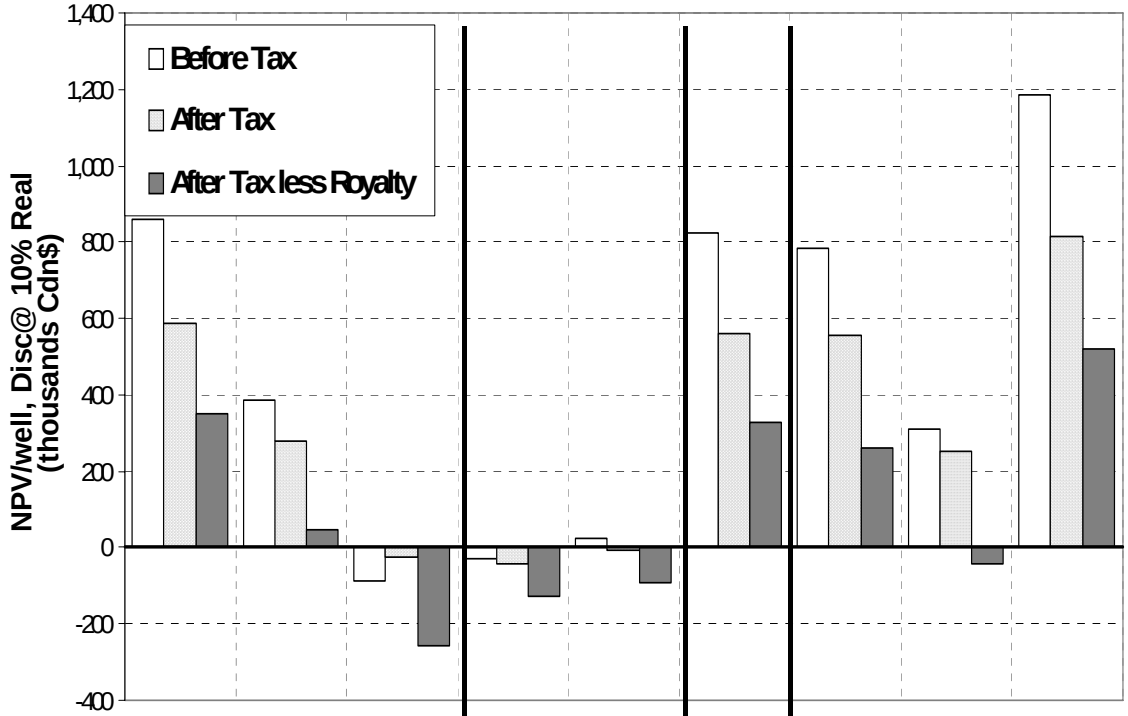
11.A. Horseshoe Canyon and Mannville Economic Comparisons: With Similar Size Conventional Pools



	Conventional	HSC	Conventional	Mannville
Price($/Mcf)	5.10	5.10	5.10	5.10
Gas Prod'n/well	0.4Bcf	0.4Bcf	1Bcf	1Bcf
Water(MMBbl/well)	0	0	0	2.02
WDC ($/Bbl)	0.0	0	0.0	0.5

Note: WDC = Water Disposal Cost

11.B. Mannville Economic Comparisons: Various Sensitivities

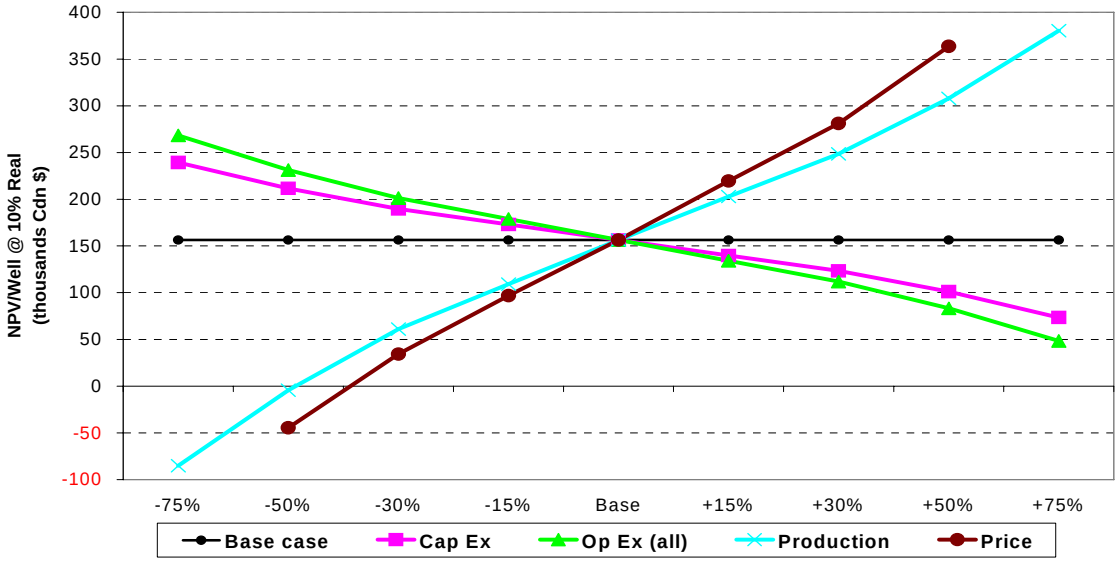


Price($/Mcf)	5.10	5.10	5.10	5.10	5.10	5.10	6.20	6.20	6.20
Gas Prod'n/well	1Bcf	1Bcf	1Bcf	0.46Bcf	0.46Bcf	1Bcf	1Bcf	1Bcf	1Bcf
Water(MMBbl/well)	2.02	2.02	2.02	0.18	0.18	0.12	2.02	2.02	0.12
WDC ($/Bbl)	0.0	0.5	1.0	1.0	0.5	1.0	0.5	1.0	1.0

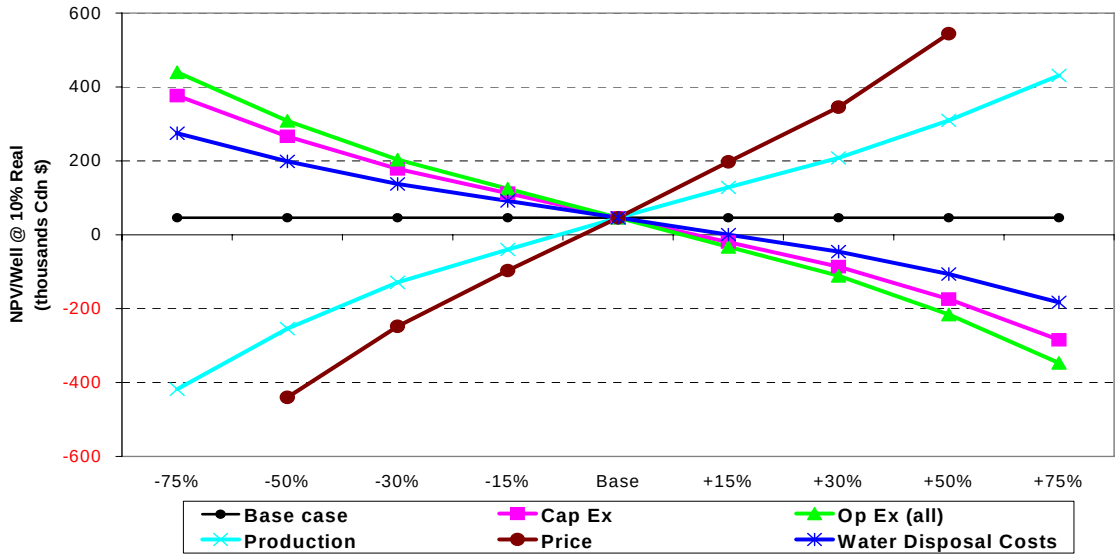
Note: WDC = Water Disposal Cost

Appendix 12
Sensitivity Analysis

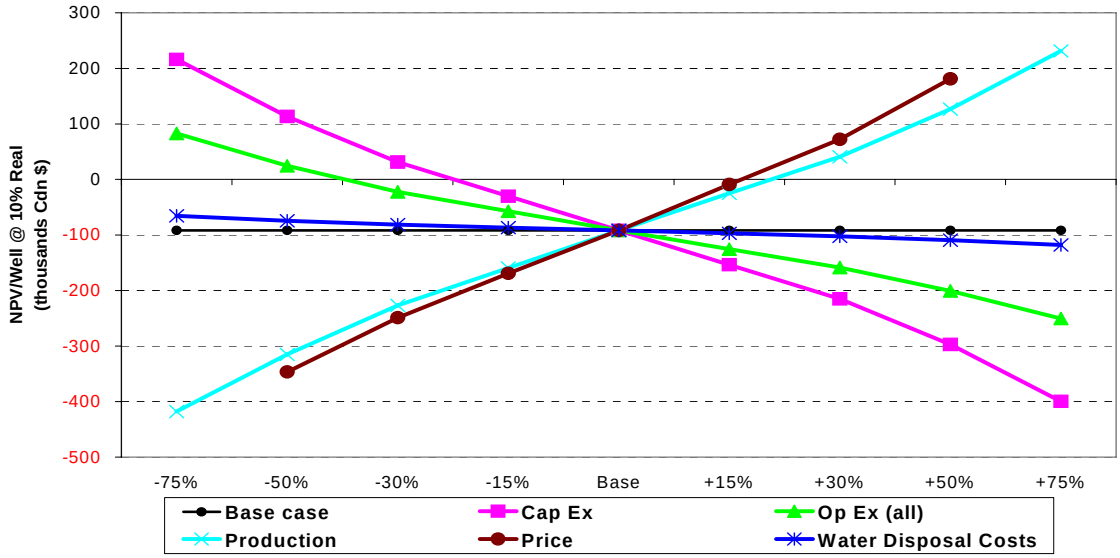
12A. Sensitivity Analysis - Horseshoe Canyon



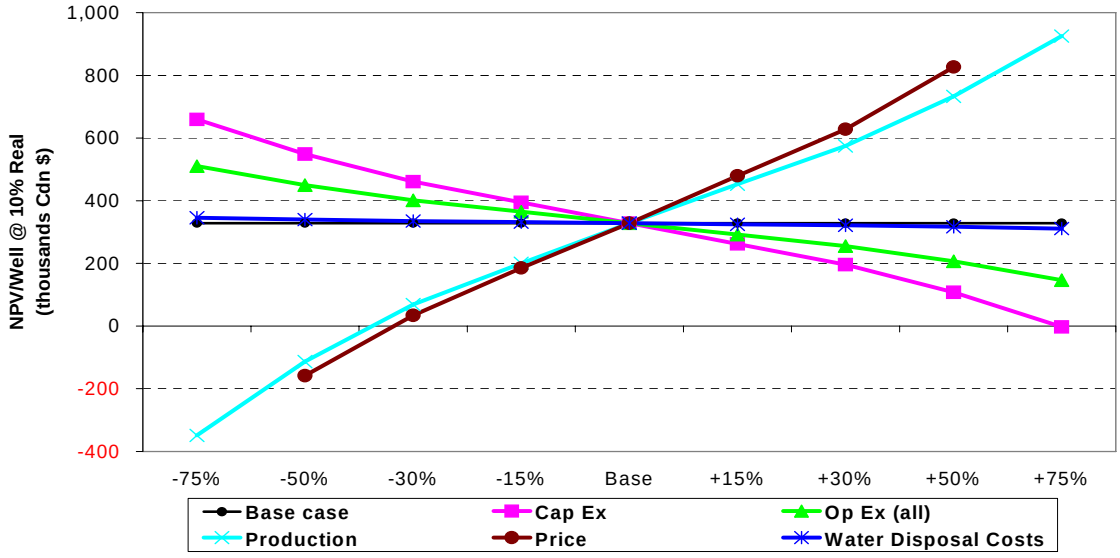
12B. Sensitivity Analysis - Mannville Base Case



12C. Sensitivity Analysis - Mannville Alternate Case



12D. Sensitivity Analysis - Mannville Base Case
(Low water gas ratio i.e. water production rate than in 11.C)



Appendix 13
Government of British Columbia's NGC Program

In March 2002, BC announced changes to the royalty and tax regulations to facilitate NGC development. These changes included:

- Water Handling Producer Cost of Service Allowance (PCOS): On a project basis for scheduled water handling related capital and operating costs. Actual costs will be used for each project. Certain capital costs incurred during experimental phases can be carried forward;

- Royalty/Tax Bank: Creates a NGC project royalty/tax bank to collect excess PCOS allowances. Banks are transferable with project interest, however they may not be used to offset royalties/taxes assessed on conventional projects or between NGC projects;

- Low Productivity Threshold: Increased from 5,000 cubic metres per day (m3/d) for conventional gas wells to 17,000 m3/d for NGC wells; and,

- Royalty Credit: $50,000 royalty credit on Crown land and $30,000 production tax credit on Freehold land for wells drilled and completed by February 24, 2004.