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Natural Gas Supply Costs in Western Canada in 2007

gas

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Foreword

The National Energy Board (NEB or the Board) is an independent federal agency that regulates several aspects of Canada's energy industry. Its purpose is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and gas pipelines as well as international and designated interprovincial power lines. The Board regulates pipeline tolls and tariffs for pipelines under its jurisdiction. In terms of specific energy commodities, the Board regulates the exports and imports of natural gas as well as exports of oil, natural gas liquids (NGLs) and electricity. Additionally, the Board regulates oil and gas exploration, development and production in Frontier lands and offshore areas not covered by provincial or federal management agreements. The Board's advisory function requires keeping under review matters over which Parliament has jurisdiction relating to all aspects of energy supply, transmission and disposal of energy in and outside Canada.

The NEB monitors energy markets to objectively analyze energy commodities and inform Canadians about trends, events and issues. The Board releases numerous research reports. This report is a briefing note – a brief report covering one aspect of energy commodities. Specifically, this report analyzes the supply costs to develop natural gas in Western Canada in 2007. It is the first stand-alone report covering this topic, and could be followed by updated versions as new information becomes available.

If a party wishes to rely on material from this report in any regulatory proceeding before the NEB, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and that party could be required to answer questions pertaining to the material.

Introduction

This briefing note provides an overview of the supply cost for the production of natural gas from the Western Canada Sedimentary Basin (WCSB). The National Energy Board (NEB) collects and analyses information about Canadian energy markets through regulatory processes and market monitoring. From these efforts, the Board publishes information such as the report on Canada's Energy Futures, several Energy Market Assessments, statistical reports, briefing notes and public presentations that address various market aspects of Canada's energy commodities.

This study examines the supply cost, or the minimum price required to produce a gigajoule (GJ) of natural gas in the WCSB in 2007, covering all costs, royalties and taxes and a rate of return. Supply costs reflect the region's competitiveness and therefore impact potential Canadian supply and pipeline utilization. Further, differing views on supply costs were raised during Alberta's royalty review in 2007 and may have led to some confusion.

Supply costs are not static. Supply costs go up and down depending on activity levels, rig and services availability, materials, labour, efficiency, technology, changes in well productivity, changing drilling targets and changing fiscal/tax regimes. Significant cost escalation was reported over the 2003 to 2006 period due to high activity and high utilization of drilling equipment and related services. Lower natural gas drilling activity in 2007 and the first half of 2008 has resulted in moderate stabilization of costs. Despite lower natural gas-related activity, increasing activity related to oil sands activity maintains upward cost pressure in western Canada. Costs of steel, fuel and labour are key drivers.

The Alberta Daily Spot NIT[1] price averaged $6.11/GJ in 2007 and $6.17 in 2006, significantly below the 2005 average price of $8.27. The reduction in natural gas prices after 2005 resulted in lower WCSB drilling activity indicating that the economics for new gas had become more challenging. Prices have risen sharply in the first half of 2008 and some analysts are expecting increased drilling in the second half of the year.

In this analysis, supply costs are calculated by region and by various formation groupings and resource types. An overview on the regions and groupings used in the analysis, a summary of the economic methodology used to calculate the supply costs and results of the economic analysis are included in the report. The appendices include the detailed descriptions of methodology, data on the regions and groupings, input assumptions and additional detailed results.

Methodology

For this study, the WCSB has been broken into geographical regions, geological formation groupings and resource types. Additional details including the reasoning behind the selection of these classifications and the methods used to generate the inputs are included in Appendix 2.

1 NIT – NOVA Inventory Transfer (Alberta's natural gas hub)

Natural gas comes from a wide variety of depths and formations, and can be either from conventional or unconventional sources that have very different costs. In this study, regions[2,3] are broken down based on categories specifically selected to be reflective of similar costs. The modified[4] regional breakdown is shown below.

Figure 1: Regional Map

Source: petroCUBE

For each region the producing formations are grouped on a geological basis, and the supply costs are calculated for each of these groupings. For example, in a particular region the gas from the Colorado resource group was assessed separately from the deeper Devonian group. There are three resource types analyzed in this study – conventional, tight and coal bed methane (CBM).

2 These classifications were originally developed by the petroCUBE information service that provides well costs and performance data.

3 petroCUBE, from geoLogic Systems Ltd. – www.petrocube.com. petroCUBE data is used and published with permission from geoLogic.

4 Saskatchewan, under petroCUBE, was considered as one whole region. For this study the province was split into two gas-producing regions – West Saskatchewan and Southwest Saskatchewan. Eastern Saskatchewan does not have gas production and is thus left out of this study.

Parameters for an average well in each region and formation are estimated and include initial production, production decline curve parameters, average depth, gas composition, shrinkage and success rate. Cost data from petroCUBE supplemented by consultations with industry is applied to the average well by region and by formation. Additional details on the categorization and cost inputs are in Appendix 2.

For a gas well to be economic predicted revenues from the production (less operating costs, royalties, taxes and a return) have to offset all of the upfront costs of purchasing the land, the geological evaluations, the drilling costs including the costs of steel and labour and the costs of facilities. Complicating the analysis is the fact that not all wells are successful, and those that are can be expected to produce at an initial rate and decline over time.

In this study, for each resource grouping, an economic analysis is undertaken to determine cash flow over the duration that each average[5] well is on production. Cash flow represents a summation of the revenues earned and expenses incurred over the life of each well. Expenses include capital and operating costs to explore, drill, complete, connect, operate, maintain and abandon the well. The cost of natural gas processing and the yield in terms of natural gas liquids is estimated. Royalties and taxes as they existed in 2007 are included. A minimum return to warrant investment is added. Revenues earned from produced volumes of natural gas and natural gas liquids are estimated. Cash flow sensitivities are tested, such as gas prices or capital cost changes. The price level that generates sufficient revenues to exactly offset the total expenses plus a return on investment establishes the supply cost for that resource grouping. The analysis is undertaken assuming that only successful wells are drilled (un-risked case) and when the costs of unsuccessful wells are incorporated (risked case). Additional details on the supply cost analysis are provided in Appendix 3.

Results

Supply Costs

Based on the assumptions listed previously, the supply costs for each grouping are listed below. The great majority of gas production from wells drilled in 2007 came from resource groupings that have sufficient production history to model the decline curve parameters. In a few groupings, there were not enough data (that is, not enough producing wells) to determine the historical well costs and for a few other groupings the historical production data varied to such an extent that it did not provide a valid production decline curve. Groupings in both of these categories were evaluated with an ‘estimated’ production decline curve, and are identified in Table 1 under ‘wells with erratic behaviour’.

A 15 percent (after tax) rate of return (ROR) is assumed for the supply cost calculations as the midpoint of a range of 10 to 20 percent obtained from public reports as well as industry consultations. This 15 percent after-tax rate translates into a higher ROR before tax. Some might consider this somewhat high for an economic hurdle rate, but with competition for investment from high oil prices in 2007 the 15 percent ROR after-tax rate was considered to be reasonable.

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5 In this study we used average numbers which aggregate the performance of thousands of wells. Every company would be in a different position with respect to land holdings, cost structure, and experience.

Table 1 below lists the resulting supply costs and payouts for each grouping with a 100 percent success rate assumed, as well as for historical success rates (see Appendix A2.3.3). These supply costs are for new gas developments in 2007 and incorporate the full costs of corresponding infrastructure. To the extent that existing infrastructure can be utilized, capital investment and supply costs would be lower than indicated here.

The weighted average[6] supply cost with a 100 percent success rate (un-risked) for the WCSB is $7.63/GJ (Alberta NIT, Canadian dollars). Using 2007 success rates, the risked weighted average supply cost is $7.88/GJ. Note that for the risked analysis, expected production is lower, but initial capital costs associated with tying in the production are also lower (see section A3.8), and therefore the risked supply cost may not be as high as expected when compared to the un-risked supply cost (see the Southwest Alberta conventional Colorado grouping as an example). Also, success rates in western Canada are relatively high due to the advanced stage of development of many of these resources. As a result, risked supply costs are generally not significantly higher than un-risked versions and do not alter the relative attraction of the Deep Basin areas.

Given the $6.11/GJ average daily Alberta NIT price and the assumption of a 15 percent ROR, the average economics for new gas development in western Canada were marginal in 2007. Factors such as the availability of existing infrastructure, different technology, capital and operating cost changes and varying well parameter assumptions cause supply costs for individual wells to differ from the average. These results are consistent with the general impressions expressed by industry players about the tight economics of new gas in 2007.

Capital and operating costs represent the largest share of producer cash flow requirements. The cash flow components are the sum of expenses over the lifetime of the well for each category. The capital costs include well and tie-in costs, land and reclamation costs. The operating and processing costs, royalties and taxes are totaled over the lifetime of the well. The return is the amount required to provide an overall 15 percent ROR. In most cases the capital component represented 30 to 40 percent of total cash flow, and the operating costs another 30 to 40 percent.

The average supply costs varied significantly from one grouping to another. Table 1 also includes the production from the wells brought on stream in 2007. The top producing groupings in 2007 are new wells in the tight gas from Mannvillle and Jurassic formations of the Alberta Deep Basin, Fort St. John’s Triassic formations and Southern Alberta’s tight gas Upper Colorado Formation. The un-risked supply costs for these groupings are $6.40, $5.94 and $9.19 respectively.

6 Production totals in 2007 from 2007 wells are used to calculate the weighted averages.

Table 1: 2007 Supply Costs and Payouts for each Grouping

Main Groupings:

Area	Resource Type	Resource Group	100% Success Rate (un-risked) Supply Cost Alberta NIT C$/GJ	100% Success Rate (un-risked) Payout years	Historical Success Rates (risked) Supply Cost Alberta NIT C$/GJ	Historical Success Rates (risked) Payout years	Historical Success Rates (risked) Success Rate %	2007 Wells Production Bcf	2007 Wells Prod'n Rank
00 - AB CBM	CBM	Mannville	$5.65	5.41	$5.65	5.41	100.0%	4.07	41
00 - AB CBM	CBM	Main HSC	$6.53	5.67	$6.53	5.67	100.0%	28.70	4
01 - Southern AB	Conventional	Tert;UprCret;UprColr	$11.51	4.12	$11.53	4.12	99.4%	7.38	27
01 - Southern AB	Conventional	Colr	$14.36	3.86	$14.58	3.89	95.5%	5.61	32
01 - Southern AB	Conventional	Mnvl	$6.17	4.27	$6.27	4.32	94.3%	10.61	20
01 - Southern AB	Tight	UprColr	$9.19	4.90	$9.19	4.91	99.8%	33.34	3
02 - Southwest AB	Conventional	Tert;UprCret;UprColr	$8.53	4.54	$8.55	4.55	99.1%	4.18	40
02 - Southwest AB	Conventional	Colr	$9.12	4.02	$11.41	4.28	60.0%	0.25	76
02 - Southwest AB	Conventional	MdlMnvl;LwrMnvl	$5.04	4.11	$5.15	4.16	93.9%	5.41	33
02 - Southwest AB	Conventional	Jur;Miss	$7.65	4.43	$7.65	4.43	100.0%	0.26	75
02 - Southwest AB	Tight	UprColr	$20.80	4.68	$22.84	4.96	75.0%	0.27	74
02 - Southwest AB	Tight	Colr	$15.69	4.29	$17.47	4.48	75.0%	0.09	78
04 - Eastern AB	Conventional	UprCret;UprColr	$18.46	4.62	$18.53	4.63	98.5%	3.37	45
04 - Eastern AB	Conventional	Colr;Mnvl	$8.58	4.47	$8.76	4.54	90.2%	21.74	7
04 - Eastern AB	Tight	UprColr	$18.31	5.20	$18.31	5.20	100.0%	0.07	80
05 - Central AB	Conventional	Tert;UprCret	$7.67	4.97	$7.82	5.04	93.0%	14.56	13
05 - Central AB	Conventional	Colr	$9.94	4.96	$10.18	5.00	94.2%	2.89	48
05 - Central AB	Conventional	Mnvl	$7.00	4.03	$7.55	4.15	81.7%	24.11	6
05 - Central AB	Tight	Colr	$8.11	5.18	$8.31	5.20	94.4%	1.15	64
06 - West Central AB	Conventional	Tert	$7.26	4.06	$7.31	4.07	98.0%	7.49	26
06 - West Central AB	Conventional	UprCret;UprColr	$5.28	4.18	$5.47	4.23	92.6%	6.44	29
06 - West Central AB	Conventional	Mnvl	$9.80	4.69	$10.19	4.75	91.8%	16.57	9
06 - West Central AB	Tight	Colr	$4.47	5.11	$4.99	5.21	79.3%	2.12	53
06 - West Central AB	Tight	Mnvl	$7.03	4.81	$7.57	4.85	86.0%	15.89	11
07 - Central Foothills	Conventional	UprColr	$9.12	4.71	$11.31	4.85	73.7%	2.70	49
07 - Central Foothills	Conventional	Miss	$5.77	4.30	$6.60	4.44	84.6%	4.76	35
07 - Central Foothills	Conventional	UprDvn;MdlDvn	$7.81	3.79	$9.48	3.89	80.0%	4.68	37
07 - Central Foothills	Tight	Jur	$12.24	3.88	$12.24	3.88	100.0%	4.20	39
08 - Kaybob	Conventional	UprColr;Colr	$8.20	4.08	$9.64	4.18	75.0%	0.93	68
08 - Kaybob	Conventional	Mnvl;Jur	$6.60	3.66	$7.41	3.76	76.8%	13.65	15
08 - Kaybob	Tight	Colr;Mnvl	$7.74	4.41	$8.23	4.46	88.1%	13.36	16
09 - AB Deep Basin	Conventional	Mnvl;Jur	$9.94	3.96	$9.94	3.96	100.0%	1.97	55
09 - AB Deep Basin	Conventional	Tri	$11.84	4.40	$11.84	4.40	100.0%	3.35	46
09 - AB Deep Basin	Tight	UprColr	$7.13	4.60	$7.33	4.62	95.2%	11.12	18
09 - AB Deep Basin	Tight	Mnvl;Jur	$6.40	4.90	$6.50	4.91	97.5%	117.22	1
10 - Northeast AB	Conventional	Mnvl;UprDvn	$9.01	3.60	$9.44	3.71	82.7%	15.21	12
11 - Peace River	Conventional	UprColr	$4.76	3.42	$4.86	3.45	92.9%	1.14	66
11 - Peace River	Conventional	Colr;UprMnvl	$5.80	3.54	$6.41	3.67	72.7%	4.97	34
11 - Peace River	Conventional	MdlMnvl;LwrMnvl	$9.43	3.31	$10.98	3.44	67.0%	8.34	23
11 - Peace River	Conventional	UprTri	$7.72	4.24	$8.56	4.34	73.7%	2.00	54
11 - Peace River	Conventional	LwrTri	$7.70	4.49	$7.81	4.51	96.0%	14.16	14
12 - Northwest AB	Conventional	MdlDvn	$11.97	3.26	$12.23	3.27	94.4%	1.92	56
13 - BC Deep Basin	Conventional	LwrTri	$5.80	4.08	$5.89	4.09	96.6%	7.72	25
13 - BC Deep Basin	Tight	Mnvl	$7.26	5.04	$7.30	5.04	98.7%	20.74	8
14 - Fort St. John	Conventional	Mnvl	$8.80	4.37	$8.93	4.39	95.7%	16.24	10
14 - Fort St. John	Conventional	Tri	$5.94	4.85	$5.97	4.86	98.2%	35.52	2
15 - Northeast BC	Conventional	UprDvn;MdlDvn	$6.71	4.47	$7.11	4.53	89.5%	1.36	60
15 - Northeast BC	Tight	UprDvn	$8.55	5.04	$8.74	5.05	96.3%	27.48	5
16 - BC Foothills	Conventional	Colr;Mnvl	$14.43	3.27	$14.73	3.28	96.7%	6.18	31
17 - Southwest SK	Tight	UprColr	$9.01	4.13	$9.01	4.13	100.0%	9.92	22
18 - Western SK	Conventional	Colr	$15.40	4.04	$15.40	4.04	100.0%	1.30	61
18 - Western SK	Conventional	MdlMnvl;LwrMnvl;Miss	$8.78	3.48	$8.78	3.48	100.0%	3.37	44
Production-Weighted Averages (and Total Production):			**$7.71**	**4.59**	**$7.94**	**4.63**	**93.7%**	**572.06**	**13**

Abbreviation	Resource Group
Tert	Tertiary
UprCret	Upper Cretaceous
UprCol	Upper Colorado
Colr	Colorado
UprMnvl	Upper Mannville
MdlMnvl	Middle Mannville
LwrMnvl	Lower Mannville
Mnvl	Mannville
Jur	Jurassic
UprTri	Upper Triassic
LwrTri	Lower Triassic
Tri	Triassic
Perm	Permian
Miss	Mississippian
UprDvn	Upper Devonian
MdlDvn	Middle Devonian
LwrDvn	Lower Devonian

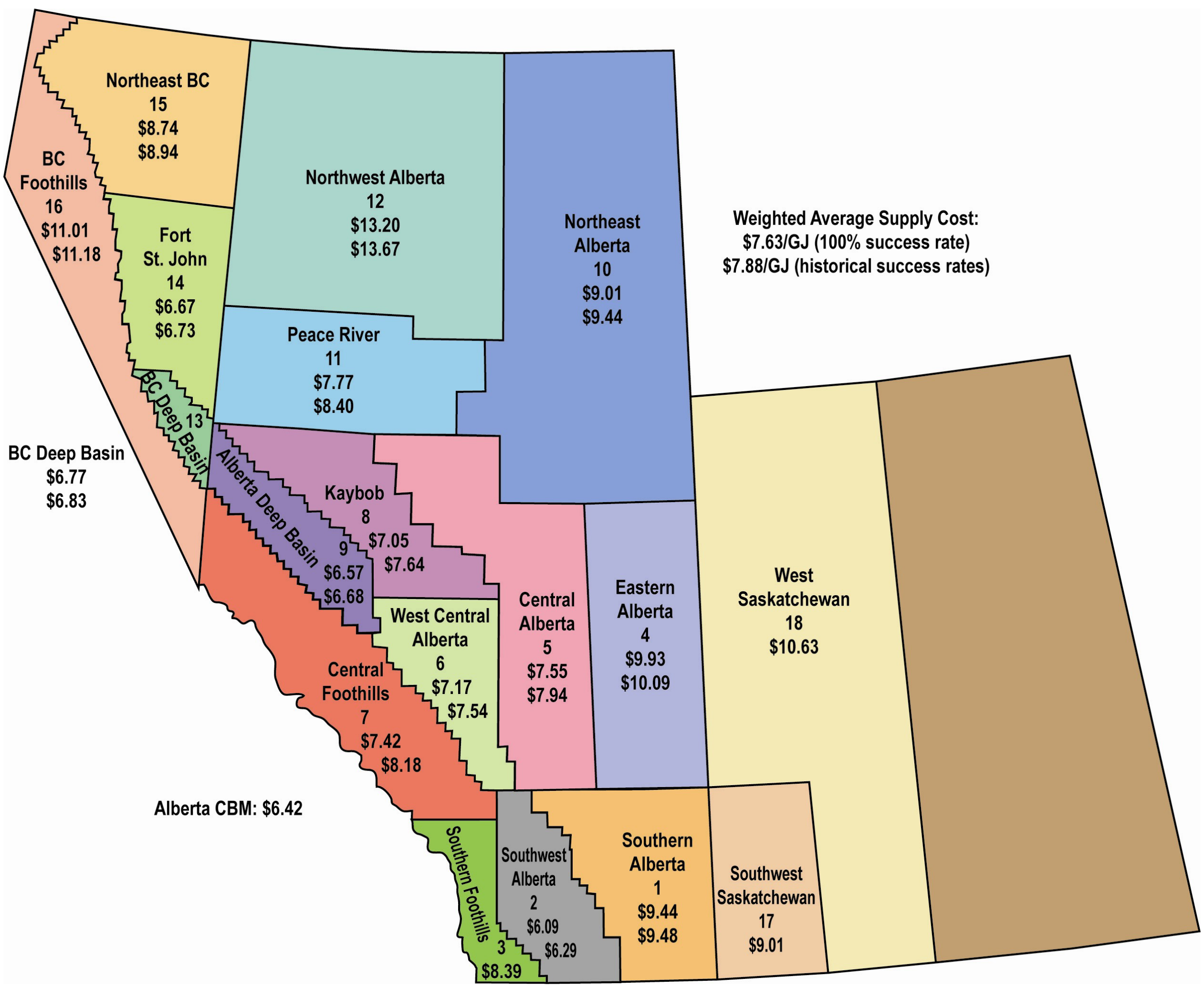
Groupings with erratic behaving wells (hard to model production profile based on history):

Area	Resource Type	Resource Group	100% Success Rate Supply Cost Alberta NIT C$/GJ	100% Success Rate Payout years	Historical Success Rates Supply Cost Alberta NIT C$/GJ	Historical Success Rates Payout years	Historical Success Rates Success Rate %	2007 Wells Production Bcf	2007 Wells Prod'n Rank
02 - Southwest AB	Conventional	UprDvn	$5.21	5.02	$5.21	5.02	100.0%	0.08	79
02 - Southwest AB	Tight	LwrMnvl	$3.23	4.86	$3.48	4.95	81.2%	3.64	43
03 - Southern Foothills	Conventional	Miss;UprDvn	$8.39	4.03	$8.39	4.03	100.0%	0.75	72
05 - Central AB	Conventional	Miss;UprDvn	$11.69	4.46	$12.54	4.51	85.7%	0.83	71
05 - Central AB	Tight	Mnvl	$7.78	4.63	$8.26	4.67	88.2%	1.76	57
06 - West Central AB	Conventional	Mnvl	$19.61	4.22	$19.61	4.22	100.0%	0.10	77
06 - West Central AB	Conventional	Miss	$9.30	4.75	$10.12	4.83	84.8%	2.36	52
06 - West Central AB	Conventional	UprDvn	$2.29	4.26	$2.50	4.34	76.9%	6.24	30
07 - Central Foothills	Conventional	Colr;Mnvl	$9.15	4.56	$10.74	4.72	80.0%	6.91	28
07 - Central Foothills	Conventional	Jur;Tri;Perm	$3.72	4.01	$3.72	4.01	100.0%	11.87	17
07 - Central Foothills	Tight	UprColr;Colr	$12.12	3.77	$12.12	3.77	100.0%	1.44	59
07 - Central Foothills	Tight	Mnvl	$14.55	3.91	$14.55	3.91	100.0%	0.90	69
08 - Kaybob	Conventional	Tri	$6.76	4.49	$7.14	4.53	88.4%	10.30	21
08 - Kaybob	Conventional	UprDvn	$5.07	4.17	$5.56	4.23	83.3%	0.65	73
09 - AB Deep Basin	Conventional	UprCret	$14.96	3.92	$14.96	3.92	100.0%	0.87	70
09 - AB Deep Basin	Conventional	UprColr	$7.71	4.77	$7.94	4.78	94.7%	2.59	50
09 - AB Deep Basin	Conventional	UprDvn	$3.67	4.12	$3.97	4.16	85.7%	3.24	47
09 - AB Deep Basin	Tight	Colr	$5.21	4.01	$5.33	4.02	95.7%	8.13	24
11 - Peace River	Conventional	Miss	$6.04	4.11	$6.63	4.24	73.3%	4.58	38
11 - Peace River	Conventional	UprDvn;MdlDvn	$15.16	2.96	$15.97	3.00	85.7%	1.12	67
12 - Northwest AB	Conventional	Mnvl	$10.07	4.30	$10.29	4.33	90.4%	4.73	36
12 - Northwest AB	Conventional	Miss	$19.00	3.26	$19.38	3.29	88.6%	2.43	51
12 - Northwest AB	Conventional	UprDvn	$15.72	2.57	$17.62	2.71	66.7%	1.23	63
13 - BC Deep Basin	Conventional	Colr	$26.30	4.04	$40.22	4.23	50.0%	0.04	81
13 - BC Deep Basin	Tight	Colr	$4.52	4.76	$4.52	4.76	100.0%	1.59	58
14 - Fort St. John	Conventional	Perm;Miss	$4.71	3.62	$4.71	3.62	100.0%	3.68	42
14 - Fort St. John	Conventional	UprDvn;MdlDvn	$5.62	4.07	$5.62	4.07	100.0%	1.28	62
15 - Northeast BC	Conventional	LwrMnvl	$11.49	4.49	$11.49	4.49	100.0%	0.00	82
15 - Northeast BC	Conventional	Perm;Miss	$15.81	4.56	$15.81	4.56	100.0%	1.14	65
16 - BC Foothills	Conventional	Tri;Perm;Miss	$9.06	3.92	$9.16	3.93	98.0%	10.86	19
Production-Weighted Averages (and Total Production):			**$7.19**	**4.17**	**$7.53**	**4.21**	**90.3%**	**95.34**	**34**

Abbreviation	Resource Group
Tert	Tertiary
UprCret	Upper Cretaceous
UprCol	Upper Colorado
Colr	Colorado
UprMnvl	Upper Mannville
MdlMnvl	Middle Mannville
LwrMnvl	Lower Mannville
Mnvl	Mannville
Jur	Jurassic
UprTri	Upper Triassic
LwrTri	Lower Triassic
Tri	Triassic
Perm	Permian
Miss	Mississippian
UprDvn	Upper Devonian
MdlDvn	Middle Devonian
LwrDvn	Lower Devonian

Production weighted average supply costs by region are shown in Figure 2. Areas that are more remote, like northern Alberta, have higher infrastructure costs and thus have some of the higher supply costs in the analysis. Areas where there are geological challenges often also have surface terrain that poses challenges to develop infrastructure and result in higher supply costs, such as the foothills regions. In the Deep Basin areas, well costs are high due to greater depth and geographical challenges, but still provide some of the lowest supply costs because of high production rates per well and yield solid economic returns. The shallower regions in southeast Alberta and southwest Saskatchewan have marginal economics. Wells in these regions are relatively low cost but produce at lower rates and are very sensitive to capital and operating cost escalations. This was evident in 2007 when gas prices declined and drilling slowed down in these regions while well activity increased in the Deep Basin areas.

Figure 2: Average 2007 Supply Costs by Region

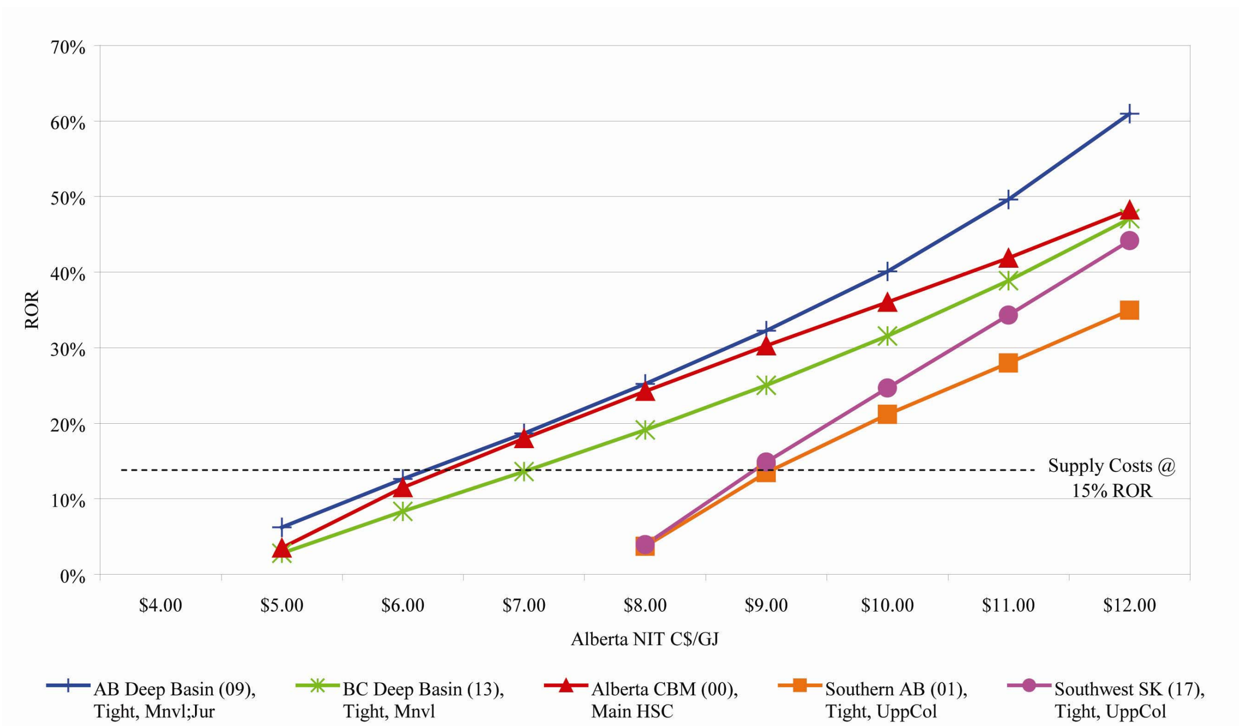


Price and Capital Cost Sensitivities

The study examined the sensitivity of supply costs to gas price. The ROR is calculated for assumed gas prices, ranging from $4 to $12/GJ Alberta NIT. Groupings with steeper slopes are more sensitive to lower gas prices, and have more to gain from higher gas prices. Figure 3 illustrates the returns over the range of gas prices for five groupings. Looking at the CBM line (red), its slope is one of the lowest under the various gas prices – that is, the returns do not increase as much as gas prices increase. However, this grouping is more robust to lower gas prices whereas the groupings with steeper slopes are more sensitive to lower gas prices. Details of gas price sensitivities are listed in Appendix 12.

Figure 4 illustrates how the supply costs change if capital costs (well and tie-in costs, land and reclamation costs) increased or decreased by 25 percent for the five groupings[7]. Groupings in areas 9 and 13, the Deep Basin, are slightly more sensitive to capital cost changes than the shallower regions. For the most part the supply cost changes are symmetrical for each grouping when capital costs increased or decreased by 25 percent. Slight asymmetry arises depending on the royalty and tax capital deductions in each province.

Figure 3: 2007 Rate of Return under various Gas Prices (un-risked)



7 Note that the sensitivity examples are unrisked. This was done for ease of comparing capital costs, that is, to look at one drilling and completing capital cost instead of a weighted average of drilling and completing and drilling and abandonment capital costs and a lower expected production level than in Appendix 6, using probability of success. Note, however, that the risked and un-risked results would be equivalent for the CBM HSC region and region 17 (100 percent success rate), and very similar for the other regions (all success rates in the high 90 percent range).

Figure 4: 2007 Supply Cost Capital Cost Sensitivities (un-risked)

Observations

Natural gas drilling activity in the WCSB has been volatile over the past few years. The level of activity is strongly affected by changes in gas price and costs. This study serves to illustrate the average cost structure in the WCSB and identify the relative economics of various resource developments.

Natural gas prices have risen strongly through mid-2008 and there are suggestions that western Canada natural gas drilling activity may increase. Should increased activity lead to markedly increased supply costs, this analysis may be repeated once sufficient cost information becomes available.

The 2007 supply costs for new gas average $7.88/GJ (with risk) [8], which is higher than the average Alberta NIT gas price of $6.11/GJ in 2007. This explains in part the pullback in total gas activity in the WCSB for the year.

In 2007 the Deep Basin areas exhibited some of the lowest supply costs, providing the rationale for the move westward that industry made from the shallower regions in southeast Alberta. The Deep Basin areas were marginally economical at the average gas price of $6.11/GJ for a 15 percent ROR, whereas for many other areas, new gas yielded returns of less than 15 percent in 2007.

8 Ranging from $4.86 to $22.84 (not including the supply costs of the erratic wells).

Capital and operating costs represent the largest share of producer cash flow requirements, which is why the economics are so sensitive to capital or operating cost changes, as shown in Figure 4. This is why factors like steel or labour costs are so important to the economics of the industry. Many other factors can affect the viability of natural gas investments including royalty changes, exchange rates, competing investments such as oil, and the market price of natural gas.

Appendix 1 – Cost Factors

Factors affecting gas economics and activity include the rising Canadian dollar and the rising price of materials such as steel. Industrial growth in China and India pushed up global demand and world prices for steel and other metals, making it more expensive for producers to buy capital equipment. A strong Canadian dollar meant it was cheaper to buy foreign goods, but it also meant reduced revenue from gas sold to American consumers in U.S dollars. The rapidly changing Canadian dollar, which increased 31 percent from $0.81US$/C$ to $1.10US$/C$[9] between January 1 and December 31 2007, made it more difficult to plan a budget. Further, the effect of the volatile exchange rate on interest rates created uncertainty for producers.

Strong oil prices (US$72.27/barrel West Texas Intermediate (WTI) average in 2007 and $66.09 in 2006) meant producers involved in conventional oil and oil sands found it attractive to invest in oil projects. Thus, budgets for natural gas activity were trimmed while the oil portion of budgets increased. This was evident from the increases in oil exploration drilling and decreased natural gas activity year-over-year in 2007. Companies also attributed natural gas prospects outside the WCSB to the decline in WCSB activity in 2007.

Strong oil prices fuelled the continuation of the strong development pace in Alberta's oil sands, which maintained competition for labour and thus labour cost levels. The lower rig counts throughout 2007, however, affected the service rig industry's activity and employment levels.

Another factor affecting gas markets in 2007 was the uncertainty concerning the Alberta government's royalty changes. Alberta's New Royalty Framework was announced on October 25, 2007. The new royalty framework, applicable to all producing wells after January 1, 2009, received mixed reviews from industry. As a result of specific concerns about royalties on deep gas, the Alberta government released their new deep gas resource program, giving royalty credits to deeper gas (more than 2500 metres vertical depth for development wells) produced in Alberta from wells drilled on or after April 10, 2008.

The Canadian federal government's Income Trust regulations, introduced October 31, 2006 also affected the industry, especially the activity levels of the smaller income trusts.

9 http://www.bankofcanada.ca/en/rates/can_us_lookup.html

Appendix 2 – Production and Cost Input Methodology

A2.1 Formation Groupings

For each region the producing formations are grouped on a geological basis, and the supply costs are calculated for each of these groupings. The formations are grouped on the basis of similarities – depth and other physical attributes such as permeability and the type of resource (see Appendices 7 and 8), drilling costs and whether, in Alberta, the formations were allowed to be co-mingled.

A2.2 Resource Types

There are three resource types analyzed in this study – conventional gas, tight gas and coal bed methane (CBM). The split between conventional gas and tight gas is based on the tight gas plays defined by Forward Energy Group Inc[10]. Three main areas of tight gas recognized in this study include: certain Cretaceous zones in the Deep Basin; the Milk River, Medicine Hat and Second White Specks formations in southeast Alberta and southwest Saskatchewan; and the Jean Marie group in northeast B.C.

Newer developments for 2007 were not included in this analysis as there was not enough data on the production profiles or cost estimates. Resource types excluded are shale gas and other CBM areas besides the Horseshoe Canyon (HSC) and Mannville resources.

A2.3 Production Inputs

Historical well data[11] from 1996 to January 2008 was used to calculate the 2007 well inputs. The inputs are used to represent the average well in that grouping drilled in 2007. The inputs include initial production, production decline curve parameters, average depth, gas composition, shrinkage and success rate (probability that a well drilled will produce on average at the assumed production level). Historical production was used as a basis for deriving the cost inputs for the groupings from the petroCUBE cost data (section A2.4).

A2.3.1 Initial Production

Using 2007 well data, initial production rates for an average well in each grouping was determined by averaging initial rates for all wells.

A2.3.2 Decline Production Curve

For wells drilled[12] in each year (1996 to 2007) decline curves were fit, with decline rates and months at each decline rate modeled. For the earlier years more data is available, and thus 'more complete' decline curves can be modeled. For wells drilled in 2007 only their initial production rates and a few months of production are available, so historical curve analysis is used to extrapolate the performance of the 2007 wells. Initial production and decline parameter inputs are listed in Appendix 6.

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10 http://www.forwardenergy.ca

11 Well data from GeoScout.

12 Wells that start producing in each year.

A2.3.3 Other Well Parameters

Historical data and previous NEB work is used to calculate average well depth, gas composition and shrinkage for each grouping. The resulting parameters can be found in Appendices 7 and 8.

To calculate the probability that a well drilled in a specific grouping will be successful (produce adequately), historical well data for each grouping was used. The ratio of successful versus unsuccessful wells was calculated for each grouping. For wells where the formation target was unknown but the depth known, statistical probability was used to estimate which formation was targeted. For each grouping, the well depth probability for each formation was modeled as a bell shaped normal distribution. If the well's depth was found to be within the formation's 80 percent confidence range, that formation was identified as a possible target for the well. If there were more than one target formation found for a well, the formation in that area that had the most wells drilled was chosen as the target formation for that well. Also, normal distribution curves could not be modeled for formations that had few historical wells. In these cases the eight surrounding townships' well data for that specific formation was pooled to estimate a normal distribution.

A2.4 Cost Inputs

petroCUBE cost data is available by region by formation (see Appendix 4 for a list of formations). The groupings used in this study sometimes contain more than one formation (see the 'Resource Group' column in Appendix 5). Thus, historical well production data for 2006-2007 is used to calculate ratios that are applied to the petroCUBE cost data. For each grouping, production data is summed for each formation. Ratios are calculated by formation (see Appendix 9), and these ratios are applied to the cost data to get average costs weighted by historical production. These costs are drilling and completion costs, tie-in costs, reclamation costs, land costs and variable and fixed operating costs. Cost data was also gathered from public presentations, industry websites and industry consultations. Processing cost inputs were derived from previous NEB work and industry consultations. CBM cost input was gathered from industry consultations and from the NEB's report 'Overview and Economics of Horseshoe Canyon Coalbed Methane Development'.[13] See Appendices 10 and 11 for the cost input tables.

13 Available at http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/hrsshcnynclbdmthn2007/hrsshcnynclbdmthn-eng.html (English) and http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/hrsshcnynclbdmthn2007/hrsshcnynclbdmthn-fra.html (French).

Appendix 3 – Economic Methodology

This appendix explains the details behind the cash flow analysis. Each grouping has cash flow determined using the assumptions described in this appendix and in Appendix 2. Cash flow sensitivities were tested by varying gas prices or capital costs. A total of 20 cash flow estimates were prepared for each grouping consisting of: one at today's costs and nine runs under varying gas price assumptions, all under a no risk assumption (probability of a successful well at 100 percent) and a risked analysis (probability of a dry well, and its accompanying costs, taken into account). Ten capital cost sensitivity tests were also run for five specific groupings.

A3.1 Cash Flow Analysis

Supply costs and rates of return (ROR) are calculated from the cash flow analysis. All cash flow components are in 2007 Canadian dollars. The net cash flow (NCF) for each time period is the total revenue less any costs and other payments due, such as taxes and royalties. The net cash flows for each time period are converted back to the first time period using a specified discount rate (the ROR) and summed to provide a net present value (NPV). The supply cost is the natural gas price that sets this NPV equal to zero. The supply cost can either be found for a specific ROR, or the ROR can be determined at a specified supply cost.

Payout can also be calculated after the supply cost or internal rate of return is found. Payout occurs when the cumulative sum of discounted cash flows, starting in the first period, equals zero. Upfront capital costs leads to negative net cash flows in the first period, but as revenues are earned, the cumulative sum of cash flows will start to become positive, that is, as net earnings start to pay off the initial capital costs.

- Supply Cost and Payout are found given a discount rate and NPV equals zero
- Discount Rate and Payout are found given a supply cost (sales price) and NPV equals zero

In this analysis production, costs and royalties are calculated on a monthly basis. The net monthly revenues, equal to production multiplied by price less costs and royalties, are summed together to get annual totals and then the taxable income and taxes due are calculated. The taxes due are subtracted from the net revenue to get annual net cash flows (NCF).

$$NCF_y = Revenue_y - Op.\ Costs_y - Royalty\ Payable_y - Taxes\ Payable_y - Cap.\ Costs_y$$

where

$$Revenue_i = \sum_k Production_{ki} * Price_{ki}$$

$$Operating\ Costs_i = Fixed\ Operating\ Costs_i + Variable\ Operating\ Costs_i$$

$$Royalty\ Payable_i = \left(\sum_k Revenue_{ki} * Royalty\ Rate_{ki}\right) - Cost\ Allowance_i * Royalty\ Rate_{i(gas)}$$

$$Taxes\ Payable_y = Taxable\ Income_y * (Provincial\ Tax\ Rate_y + Federal\ Tax\ Rate_y)$$

Capital $Costs_i$	= Drilling, Casing, Completing, Tie-In costs + Land Costs in first month
	= Reclamation costs in last month of production
	= 0 otherwise

i = month i
y = year y
k = product k (natural gas, ethane, propane, butane, pentanes plus and sulphur)

A3.2 Revenue

Revenue is determined by multiplying the marketable production volume by price, for each product. These revenues are summed to get total revenue. For some groupings products other than natural gas are included. Butane, propane, ethane, pentanes plus and sulphur are all possible products of processing natural gas. Since these products produce income streams this revenue needs to be accounted for in the well economics. The compositions of gas streams for each grouping are given in Appendix 7.

The natural gas price is either solved for in the cash flow analysis as a supply cost, or it is assumed and inputted into the analysis to find the ROR. Prices tested range from \$4 to \$12/GJ, in one-dollar increments[14]. The natural gas price is the market price per gigajoule in 2007 Canadian dollars. The price the producer receives at the wellhead is the market price less \$0.15/GJ to account for transportation. This wellhead price is for 2007, and future prices are escalated at an annual real inflation rate of two percent. For instance, if the price in 2007 is \$3.85 (a market price of \$4 less \$0.15), the price in 2008 will be C2007\$3.93/GJ (a two percent real annual inflation applied to the \$3.85), and so on for subsequent years of production.

Prices for the other products are assumed as follows. The plant gate sulphur price for 2007 is set at \$34 per tonne, in 2007 Canadian dollars. It is then escalated for future years at a real annual inflation rate of two percent. Price ratios are applied to assign prices for the other products. The propane price for a given year is set at 45 percent above the wellhead natural gas price, the butane price is 55 percent above the wellhead natural gas price and the pentanes and heavier molecules (pentanes plus) price is double the wellhead natural gas price. Converting raw gas produced into these different products requires yield factors. The assumed factor for propane is 25.394 GJ per cubic metre of raw gas produced. The factor for butane is 28.345 GJ per cubic metre and 31.00 GJ per cubic metre for pentanes plus.

A3.3 Success and Abandonment

Since there is a chance that a well drilled may be dry – unsuccessful for gas production – a probability is applied in the analysis to take this risk into account. The probability the well is unsuccessful and abandoned, for each grouping, is provided in Appendix 8. The probability of success, that the well drilled does produce adequately, is equal to one minus the probability of abandonment. To take this risk into account in the analysis, the production for each month is multiplied by the probability of success, to get an expected production, or risked production, and

14 The monthly average of the Alberta NIT (AECO-C) daily spot prices have ranged from C\$4.44 to \$11.78/GJ over the past five years (January 2003 to October 2007). The \$4-12 gas price range is based on this historical range. Historical gas price source: http://www.sproule.com/prices/hist_gas.htm.

multiplied with costs each month[15]. Since revenue equals production multiplied by price, the revenue carried forward in all calculations is risked revenue, and along with the risked costs the economic analysis is an analysis including risk.

A3.4 Capital Costs

Initial capital costs are assumed to apply in the first month of production, except for the reclamation cost, which occurs in the last month of production, and is escalated by the two percent inflation rate. Note wells that are unsuccessful have different capital costs (and no operating costs into the future since there is no production).

A3.5 Operating and Processing Costs

Operating costs are incurred every month of production. There are two types of operating costs – fixed and variable. Fixed operating costs are the same every month, regardless of how much is produced from the well that month. These could include equipment leases, maintenance and certain manpower. Variable operating costs are a cost per unit of marketable production. The variable costs are in 2007 Canadian dollars and are the costs incurred in 2007. Future operating costs are inflated at the two percent annual rate.

Raw gas needs to be processed into marketable gas before going to market. These processing costs are dollars per unit of production. Processing costs are inflated at the two percent real annual inflation rate.

A3.6 Royalties

Production is assumed to occur on Crown lands, which means royalties must be paid to the provincial government. Royalties exist because citizens own the natural resource (natural gas and natural gas liquids in this case) and must be compensated by producers who extract the resource for revenues.

Royalty frameworks in place as of December 2006 for British Columbia and Saskatchewan are used[16]. The new royalty framework for Alberta, released October 2007[17], is used in the Alberta economic analysis for production on or after January 1, 2009. Gross royalties payable are the product of the royalty rate (in percent) and the gross revenues (sales price assumed multiplied with production). Along with these gross royalty calculations, capital cost deductions, low productivity and deep well royalty relief adjustments are deducted from the gross royalty amounts to get actual net royalty amounts payable to the respective provincial government for each producing month.

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15 Expected BTI = (Probability of Success)*BTI + (Probability of Abandonment)*zero BTI = (Probability of Success)*BTI since there is no income if the well is abandoned (dry).

16 Oil and Gas Fiscal Regimes: Western Canadian Provinces and Territories, December 2006: http://www.energy.gov.ab.ca/Tenure/pdfs/FISREG.pdf

17 Alberta's New Royalty Framework: http://www.energy.gov.ab.ca/About_Us/1293.asp

A3.6.1 B.C. Royalties

The Base 9[18] gas royalty formula is used to calculate the B.C. gross royalties[19] for natural gas. This formula retains nine percent of the price when the price is less than or equal to the select price, and 40 percent of the price in excess of the select price. The assumed select price is $50/$m^3$ ($1.41/Mcf). The royalty rate must be in the range of nine to 27 percent. Wells producing less than 5000 10^3m^3/day on average for a month will see a decrease in the royalty rate.

Other products produced along with the natural gas are also subject to royalty payments. Royalties on natural gas liquids are levied at a flat rate of 20 percent of the sales volume and royalties on sulphur are levied at a flat rate of 16 2/3 percent of the sales volume. The gross royalty payable is the sum of all royalties payable for each product.

In B.C., producers can deduct cost allowances and qualifying deep well adjustments. Gas producers are eligible to receive the producer cost of service allowance (PCOS) for field gathering, dehydration, compression, field processing and conservation. That is, the total costs for these items, multiplied by the natural gas royalty rate, are deducted from gross royalties. Vertical wells that have a depth of at least 2500 metres or horizontal wells with a depth of 2300 metres qualify for deep well royalty holiday credits. This is applied to future royalties[20].

A3.6.2 Alberta Royalties

The royalty rate formulas for oil and gas in Alberta were updated in October 2007 with the provincial government's new royalty rate framework. These new royalty formulas come into effect on or after January 1, 2009. Thus, in this analysis, the existing royalty formulas prior to this announcement are assumed for production in 2007 and 2008 and production occurring after 2008 adopts the new royalty formulas.

The new natural gas royalty calculation is made up of two components – a price component and a quantity component. The sum of the two components makes up the royalty rate. Each component cannot exceed 30 percent, and the sum – the total royalty rate – has a minimum of five percent and a maximum of 50 percent. The quantity component can also be decreased by a depth factor. If a well has a measured depth of 2000 metres or more, there will be a depth factor based on the quantity of gas produced. With this depth factor adjustment, the quantity component of the royalty rate can be negative. Existing royalty rates, as of December 2006[1], for ethane, propane, butane, pentanes plus and sulphur are used in this analysis. The royalty rate is then multiplied by gross revenues to find the gross royalty in each month.

Like B.C., applicable costs can be deducted from the gross royalty, including annual capital costs, monthly operating costs and annual custom processing costs. These costs are multiplied by the natural gas royalty rate and subtracted from the total gross royalty amount to get a net royalty payable amount each month.

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18 Gas produced from gas wells drilled on land acquired after June 1, 1998 which are completed within five years of the date rights are issued.

19 For more information use the source noted in footnote 16.

20 Since royalties payable cannot be negative, any amount of deductions exceeding the gross royalty payable for a month is carried forward into the next month and added to the deductions for that month, and so on until the deductions have all been used.

There is also a deep gas royalty relief in place. The current relief formula is used in this analysis. The Alberta government announced new deep resource programs to promote high cost oil and gas development. However, these new programs only apply to wells that begin drilling on or after April 10, 2008, and since this analysis is looking at the economics of 2007 wells these programs are not included in the calculations.

A3.6.3 Saskatchewan Royalties

The royalty formula for 'Fourth Tier[21] Gas from Gas Wells' is used to calculate the royalty rate for gas production in Saskatchewan. If the monthly gas production from a well is less than 25 10^3m^3/month, the royalty rate is zero percent. If the monthly production is higher than 25 10^3m^3, the royalty rate is calculated based on one of two formulas – one if the production is higher than 115.4 10^3m^3/day and one if the production ranges from 25-115.4 10^3m^3/day.

There is also a cost allowance to reduce royalties payable, but unlike British Columbia and Alberta, the capital cost deduction is not based on dollars actually spent, but is a fixed gas cost allowance of $10 per thousand cubic metres for all gas types. This allowance is in recognition of the gathering and processing costs. There are no NGL royalties, so higher processing costs are not recognized in the allowance. Also, it is assumed that there is no sulphur production in Saskatchewan, and hence, no sulphur royalty.

A3.7 Taxes

New corporate tax rates in Canada were announced and passed in the fall of 2007, and are used in this analysis. The 2007 corporate income tax rate is 22.12 percent for 2007, and will drop to 15 percent by 2012. These rates presented below are used in the analysis and it is assumed that production beyond 2012 will face the 15 percent tax rate.

	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Canada Tax Rate	22.12%	19.5%	19.0%	18.0%	16.5%	15.0%

Existing provincial tax rates, as of October 2007, are assumed. The provincial tax rates are assumed constant throughout the productive lifetime of each well. The tax rates are:

	British Columbia	**Alberta**	**Saskatchewan**
Provincial Tax Rate	12%	10%	14%

Before tax income (BTI) is revenue (production multiplied by price) less operating costs and royalty payable. BTI's are calculated for each month and summed to provide a BTI for each calendar year. Taxable income is BTI less allowed depreciation and capital cost allowances in a given year. The tax rates are multiplied by the annual taxable income to get federal and provincial taxes payable for each producing year of a well. Annual after tax income (ATI) is then calculated by subtracting the taxes payable from the BTI for each year.

21 Gas produced from gas wells drilled on or after October 1, 2002.

A3.8 Net Cash Flows (NCF) and Solving

The NCF for each year is the risked ATI less capital costs. The initial capital costs are assumed to occur in the first month, so the net cash flow in the first month will be negative. The reclamation cost in the last producing month will also lead to negative cash flow for that month in most cases. For all other months, there are no assumed capital costs, and since production will only continue while the revenues can cover the operating costs, net cash flows are positive. As production falls the revenue will, at some point, not cover operating costs and hence, production is assumed to stop.

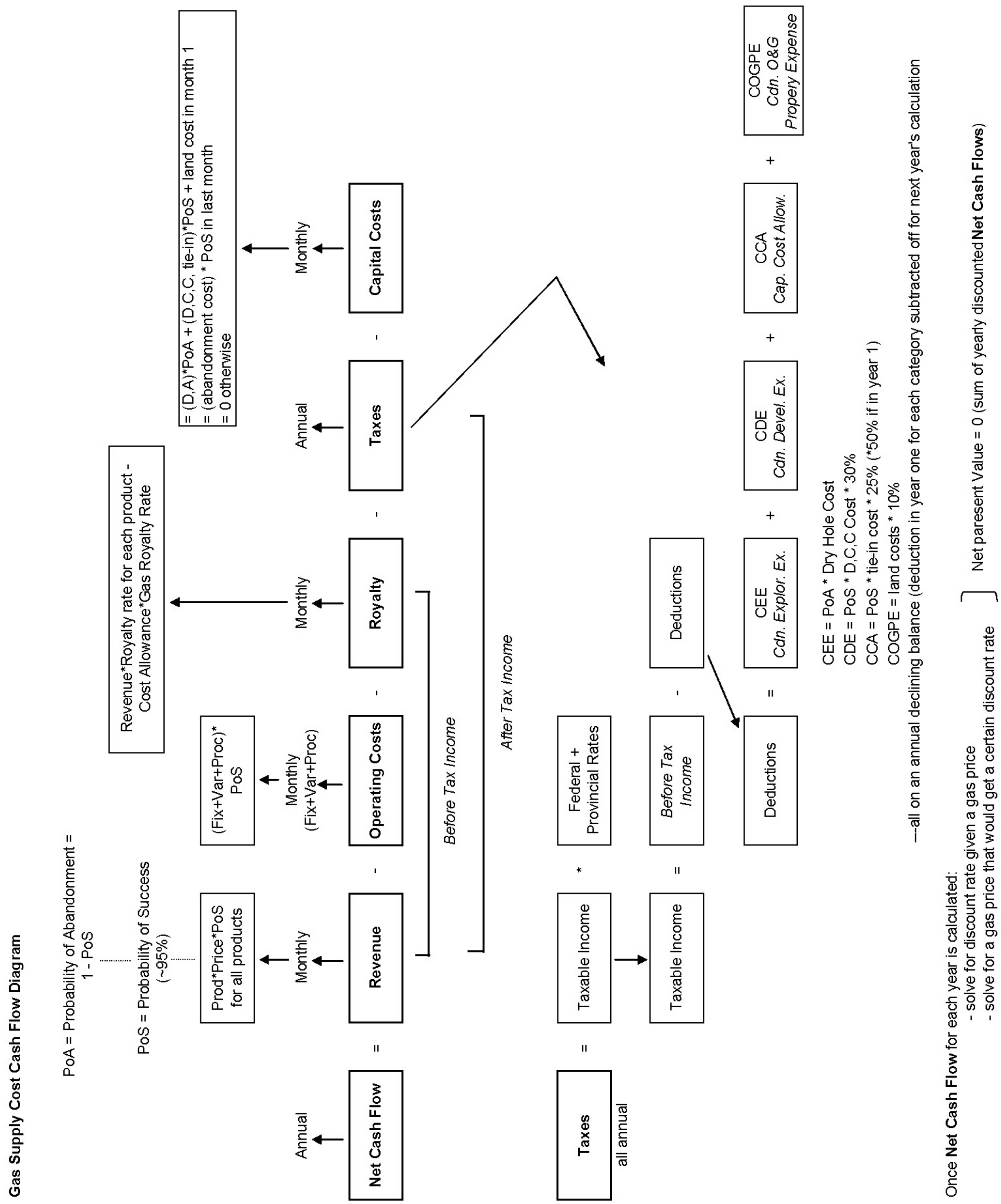
The costs must also be weighed by the probability of success. If the well is abandoned, the producer will incur land costs, drilling and abandonment costs and a reclamation cost. If the well is successful, the producer will incur land costs, drilling, casing and tie-in costs and reclamation costs. So, the total initial capital cost is:

Initial Capital Cost = land costs + (probability of an unsuccessful well) * dry hole cost
+ (probability of success)* (drilling, casing costs + tie-in costs)

The capital cost in the last production month is the inflated reclamation cost. Once the NCF's are determined, the NPV and payouts are calculated, as well as either the ROR or the supply cost for an average well in each grouping.

A summary of the economic methodology is presented on the following page.

Figure A1: Cash Flow Diagram



Appendix 4 – Formations

Abbreviation	Resource Group
Tert	Tertiary
UprCret	Upper Cretaceous
UprCol	Upper Colorado
Colr	Colorado
UprMnvl	Upper Mannville
MdlMnvl	Middle Mannville
LwrMnvl	Lower Mannville
Mnvl	Mannville
Jur	Jurassic
UprTri	Upper Triassic
LwrTri	Lower Triassic
Tri	Triassic
Perm	Permian
Miss	Mississippian
UprDvn	Upper Devonian
MdlDvn	Middle Devonian
LwrDvn	Lower Devonian

Note, for example, the Mannville formation is listed as Mnvl, or could be split up into the upper, middle and lower Mannville formations.

Appendix 5 - Groupings

Area Name	Area Number	Resource Type	Resource Group
CBM Area	00	CBM	Main HSC
CBM Area	00	CBM	Mannville
Southern Alberta	01	Conventional	Tert;UprCret;UprColr
Southern Alberta	01	Conventional	Colr
Southern Alberta	01	Conventional	Mnvl
Southern Alberta	01	Tight	UprColr
Southwest Alberta	02	Conventional	Tert;UprCret;UprColr
Southwest Alberta	02	Conventional	Colr
Southwest Alberta	02	Conventional	MdlMnvl;LwrMnvl
Southwest Alberta	02	Conventional	Jur;Miss
Southwest Alberta	02	Conventional	UprDvn
Southwest Alberta	02	Tight	UprColr
Southwest Alberta	02	Tight	Colr
Southwest Alberta	02	Tight	LwrMnvl
Southern Foothills	03	Conventional	Miss;UprDvn
Eastern Alberta	04	Conventional	UprCret;UprColr
Eastern Alberta	04	Conventional	Colr;Mnvl
Eastern Alberta	04	Tight	UprColr
Central Alberta	05	Conventional	Tert;UprCret
Central Alberta	05	Conventional	Colr
Central Alberta	05	Conventional	Mnvl
Central Alberta	05	Conventional	Miss;UprDvn
Central Alberta	05	Tight	Colr
Central Alberta	05	Tight	Mnvl
West Central Alberta	06	Conventional	Tert
West Central Alberta	06	Conventional	UprCret;UprColr
West Central Alberta	06	Conventional	Mnvl
West Central Alberta	06	Conventional	LwrMnvl; Jur
West Central Alberta	06	Conventional	Miss
West Central Alberta	06	Conventional	UprDvn
West Central Alberta	06	Tight	Colr
West Central Alberta	06	Tight	Mnvl
Central Foothills	07	Conventional	UprColr
Central Foothills	07	Conventional	Colr;Mnvl
Central Foothills	07	Conventional	Jur;Tri;Perm
Central Foothills	07	Conventional	Miss
Central Foothills	07	Conventional	UprDvn;MdlDvn
Central Foothills	07	Tight	UprColr;Colr
Central Foothills	07	Tight	Mnvl
Central Foothills	07	Tight	Jur
Kaybob	08	Conventional	UprColr;Colr
Kaybob	08	Conventional	Mnvl;Jur
Kaybob	08	Conventional	Tri
Kaybob	08	Conventional	UprDvn
Kaybob	08	Tight	Colr;Mnvl

Area Name	Area Number	Resource Type	Resource Group
Alberta Deep Basin	09	Conventional	UprCret
Alberta Deep Basin	09	Conventional	UprColr
Alberta Deep Basin	09	Conventional	Mnvl;Jur
Alberta Deep Basin	09	Conventional	Tri
Alberta Deep Basin	09	Conventional	UprDvn
Alberta Deep Basin	09	Tight	UprColr
Alberta Deep Basin	09	Tight	Colr
Alberta Deep Basin	09	Tight	Mnvl;Jur
Northeast Alberta	10	Conventional	Mnvl;UprDvn
Peace River	11	Conventional	UprColr
Peace River	11	Conventional	Colr;UprMnvl
Peace River	11	Conventional	MdlMnvl;LwrMnvl
Peace River	11	Conventional	UprTri
Peace River	11	Conventional	LwrTri
Peace River	11	Conventional	Miss
Peace River	11	Conventional	UprDvn;MdlDvn
Northwest Alberta	12	Conventional	Mnvl
Northwest Alberta	12	Conventional	Miss
Northwest Alberta	12	Conventional	UprDvn
Northwest Alberta	12	Conventional	MdlDvn
BC Deep Basin	13	Conventional	Colr
BC Deep Basin	13	Conventional	LwrTri
BC Deep Basin	13	Tight	Colr
BC Deep Basin	13	Tight	Mnvl
Fort St. John	14	Conventional	Mnvl
Fort St. John	14	Conventional	Tri
Fort St. John	14	Conventional	Perm;Miss
Fort St. John	14	Conventional	UprDvn;MdlDvn
Northeast BC	15	Conventional	LwrMnvl
Northeast BC	15	Conventional	Perm;Miss
Northeast BC	15	Conventional	UprDvn;MdlDvn
Northeast BC	15	Tight	UprDvn
BC Foothills	16	Conventional	Colr;Mnvl
BC Foothills	16	Conventional	Tri;Perm;Miss
Southwest Saskatchewan	17	Tight	UprColr
West Saskatchewan	18	Conventional	Colr
West Saskatchewan	18	Conventional	MdlMnvl;LwrMnvl;Miss

Appendix 6 – Decline Parameters

Area	Resource Type	Resource Group	Initial Production mmcf/d	1st Decline Rate	2nd Decline Rate	3rd Decline Rate	4th Decline Rate	5th Decline Rate	Months to 2nd Decline	Months to 3rd Decline	Months to 4th Decline	Months to 5th Decline
00	CBM	Main HSC	0.077	0.02	0.17	0.1	0.1	0.1	12	60	500	500
00	CBM	Mannville	0.38	0.01	0.4	0.2	0.15	0.1	15	30	50	100
01	Conventional	Tert;UprCret;UprColr	0.08	0.75	0.3	0.24	0.15	0.15	10	30	100	500
01	Conventional	Colr	0.13	1	0.38	0.25	0.15	0.15	17	30	80	500
01	Conventional	Mnvl	0.3	0.7	0.45	0.2	0.15	0.15	12	35	80	500
01	Tight	UprColr	0.084	0.85	0.35	0.21	0.15	0.11	8	20	42	100
02	Conventional	Tert;UprCret;UprColr	0.125	1	0.35	0.17	0.17	0.17	9	35	500	500
02	Conventional	Colr	0.16	0.8	0.3	0.2	0.2	0.2	10	75	500	500
02	Conventional	MdlMnvl;LwrMnvl	0.62	1.2	0.55	0.25	0.17	0.17	12	30	65	500
02	Conventional	Jur;Miss	0.34	1.5	0.2	0.2	0.2	0.2	10	500	500	500
02	Conventional	UprDvn	0.55	0.75	0.25	0.11	0.05	0.05	20	50	100	500
02	Tight	UprColr	0.057	1.2	0.3	0.15	0.15	0.15	10	40	500	500
02	Tight	Colr	0.11	1	0.5	0.22	0.15	0.15	10	30	70	500
02	Tight	LwrMnvl	0.5	0.55	0.3	0.18	0.15	0.15	10	25	50	500
03	Conventional	Miss;UprDvn	3.4	0.45	0.3	0.23	0.23	0.23	10	34	500	500
04	Conventional	UprCret;UprColr	0.051	0.95	0.41	0.28	0.1	0.1	7	25	60	500
04	Conventional	Colr;Mnvl	0.184	0.85	0.53	0.25	0.16	0.16	7	20	50	500
04	Tight	UprColr	0.053	0.75	0.55	0.15	0.08	0.08	7	20	40	500
05	Conventional	Tert;UprCret	0.147	0.75	0.45	0.25	0.1	0.1	8	20	50	500
05	Conventional	Colr	0.163	0.65	0.45	0.25	0.12	0.12	7	20	40	500
05	Conventional	Mnvl	0.355	0.7	0.55	0.37	0.15	0.15	7	20	50	500
05	Conventional	Miss;UprDvn	0.235	0.65	0.4	0.25	0.15	0.15	7	30	50	500
05	Tight	Colr	0.256	0.85	0.45	0.2	0.1	0.1	4	20	50	500
05	Tight	Mnvl	0.392	0.65	0.4	0.25	0.15	0.15	7	20	50	500
06	Conventional	Tert	0.18	1	0.35	0.16	0.16	0.16	7	45	500	500
06	Conventional	UprCret;UprColr	0.42	1	0.45	0.25	0.13	0.13	8	26	70	500
06	Conventional	Mnvl	0.25	1.5	0.45	0.23	0.2	0.2	8	25	45	500
06	Conventional	LwrMnvl;Jur	0.48	0.75	0.4	0.16	0.12	0.12	12	32	65	500
06	Conventional	Miss	0.57	0.6	0.3	0.13	0.13	0.13	10	48	500	500
06	Conventional	UprDvn	1.25	0.2	0.2	0.2	0.2	0.2	500	500	500	500
06	Tight	Colr	0.44	0.3	0.15	0.12	0.12	0.12	25	55	500	500
06	Tight	Mnvl	0.46	0.65	0.27	0.17	0.11	0.11	12	45	80	500
07	Conventional	UprColr	0.72	0.8	0.3	0.2	0.15	0.12	12	20	60	500
07	Conventional	Colr;Mnvl	1.05	0.8	0.35	0.15	0.15	0.15	8	45	500	500
07	Conventional	Jur;Tri;Perm	5.7	0.35	0.2	0.2	0.2	0.2	30	500	500	500
07	Conventional	Miss	2.9	0.6	0.2	0.11	0.11	0.11	12	45	500	500
07	Conventional	UprDvn;MdlDvn	1.8	0.01	0.25	0.15	0.15	0.15	12	90	500	500
07	Tight	UprColr;Colr	0.65	0.55	0.45	0.25	0.25	0.25	20	40	500	500
07	Tight	Mnvl	0.45	0.4	0.25	0.25	0.25	0.25	30	500	500	500
07	Tight	Jur	1.75	1.1	0.4	0.25	0.25	0.25	10	25	500	500

Area	Resource Type	Resource Group	Initial Production mmcf/d	1st Decline Rate	2nd Decline Rate	3rd Decline Rate	4th Decline Rate	5th Decline Rate	Months to 2nd Decline	Months to 3rd Decline	Months to 4th Decline	Months to 5th Decline
08	Conventional	UprColr;Colr	0.46	1	0.55	0.24	0.24	0.24	10	20	500	500
08	Conventional	Mnvl;Jur	1.1	0.9	0.45	0.25	0.16	0.12	10	50	500	500
08	Conventional	Tri	1.1	1	0.3	0.2	0.14	0.14	12	45	75	500
08	Conventional	UprDvn	1.3	1	0.25	0.25	0.25	0.25	12	500	500	500
08	Tight	Colr;Mnvl	0.64	1.1	0.5	0.24	0.12	0.12	7	20	75	500
09	Conventional	UprCret	0.33	1.35	0.45	0.25	0.15	0.15	6	23	100	500
09	Conventional	UprColr	0.56	0.8	0.26	0.2	0.12	0.12	7	30	75	500
09	Conventional	Mnvl;Jur	0.64	0.75	0.33	0.12	0.12	0.12	12	80	500	500
09	Conventional	Tri	0.62	0.6	0.3	0.18	0.18	0.18	15	40	500	500
09	Conventional	UprDvn	6.5	0.01	1.5	0.6	0.2	0.2	6	12	24	500
09	Tight	UprColr	0.60	1	0.4	0.22	0.13	0.13	7	20	65	500
09	Tight	Colr	1.3	1.2	0.45	0.23	0.23	0.23	8	35	500	500
09	Tight	Mnvl;Jur	1.2	0.65	0.37	0.22	0.15	0.12	15	30	50	70
10	Conventional	Mnvl;UprDvn	0.185	0.5	0.4	0.22	0.22	0.22	7	25	500	500
11	Conventional	UprColr	0.55	0.65	0.35	0.27	0.27	0.27	14	50	500	500
11	Conventional	Colr;UprMnvl	0.59	0.55	0.3	0.3	0.3	0.3	25	500	500	500
11	Conventional	MdlMnvl;LwrMnvl	0.58	0.9	0.45	0.25	0.2	0.2	18	45	90	500
11	Conventional	UprTri	0.7	0.8	0.2	0.2	0.2	0.2	20	500	500	500
11	Conventional	LwrTri	0.6	0.6	0.25	0.15	0.15	0.15	20	50	500	500
11	Conventional	Miss	0.85	1	0.25	0.2	0.2	0.2	12	100	500	500
11	Conventional	UprDvn;MdlDvn	0.8	1.5	0.35	0.35	0.35	0.35	20	500	500	500
12	Conventional	Mnvl	0.208	0.75	0.45	0.2	0.17	0.17	7	20	45	500
12	Conventional	Miss	0.267	0.95	0.65	0.45	0.25	0.25	7	30	45	500
12	Conventional	UprDvn	0.676	1.99	0.75	0.25	0.25	0.25	7	55	500	500
12	Conventional	MdlDvn	0.532	0.65	0.55	0.45	0.45	0.45	7	25	500	500
13	Conventional	Colr	0.145	0.5	0.3	0.22	0.22	0.22	14	30	500	500
13	Conventional	LwrTri	2.2	0.01	0.7	0.24	0.24	0.24	6	20	500	500
13	Tight	Colr	1.3	0.5	0.15	0.15	0.15	0.15	20	500	500	500
13	Tight	Mnvl	2.7	1.5	0.3	0.15	0.1	0.1	10	24	70	500
14	Conventional	Mnvl	0.43	0.65	0.3	0.2	0.12	0.12	13	55	90	500
14	Conventional	Tri	0.95	0.8	0.35	0.2	0.14	0.14	8	32	60	500
14	Conventional	Perm;Miss	2.1	0.5	0.2	0.2	0.2	0.2	50	500	500	500
14	Conventional	UprDvn;MdlDvn	2.3	0.45	0.25	0.25	0.25	0.25	24	500	500	500
15	Conventional	LwrMnvl	0.219	0.6	0.25	0.2	0.2	0.2	7	20	500	500
15	Conventional	Perm;Miss	0.219	0.65	0.45	0.15	0.15	0.15	7	35	500	500
15	Conventional	UprDvn;MdlDvn	1.655	0.65	0.55	0.15	0.15	0.15	7	40	500	500
15	Tight	UprDvn	1.155	0.85	0.55	0.25	0.15	0.15	7	20	50	500
16	Conventional	Colr;Mnvl	1.23	0.55	0.5	0.5	0.5	0.5	15	500	500	500
16	Conventional	Tri;Perm;Miss	1.693	0.45	0.35	0.25	0.25	0.25	7	25	500	500
17	Tight	UprColr	0.073	0.8	0.43	0.31	0.22	0.15	8	18	35	60
18	Conventional	Colr	0.09	0.75	0.35	0.25	0.17	0.17	15	30	60	500
18	Conventional	MdlMnvl;LwrMnvl;Miss	0.23	0.8	0.4	0.3	0.25	0.25	14	40	70	500

Appendix 7 – Gas Compositions

Area	RsrcType	Resource Group	C3 barrels per marketable mmcf	C4 barrels marketable mmcf	C5+ barrels marketable mmcf	Sulphur tonnes per marketable mmcf
00	CBM	Main HSC	0	0	0	0
00	CBM	Mannville	0	0	0	0
01	Conventional	Tert;UprCret;UprColr	0	0.08	0.41	0
01	Conventional	Colr	0.05	0.48	1.92	0.0007
01	Conventional	Mnvl	0.38	1.67	5.21	0.0025
01	Tight	UprColr	0	0.1	0.39	0
02	Conventional	Tert;UprCret;UprColr	0.02	0.12	0.44	0.001
02	Conventional	Colr	0	0.2	0.94	0.0009
02	Conventional	MdlMnvl;LwrMnvl	0.46	1.91	7.01	0.0109
02	Conventional	Jur;Miss	0.75	2.69	13.11	0.1813
02	Conventional	UprDvn	0.08	0.66	11.27	5.462
02	Tight	UprColr	0	0.04	0.23	0
02	Tight	Colr	0.1	0.63	1.8	0
02	Tight	LwrMnvl	0.6	2.07	8.22	0.0829
03	Conventional	Miss;UprDvn	5.94	6.04	21.6	4.2071
04	Conventional	UprCret;UprColr	0	0.06	0.28	0.0008
04	Conventional	Colr;Mnvl	0.02	0.28	0.96	0.0017
04	Tight	UprColr	0	0.03	0.13	0
05	Conventional	Tert;UprCret	0.01	0.16	0.72	0.0016
05	Conventional	Colr	0.31	0.95	3.17	0
05	Conventional	Mnvl	0.65	1.86	5.12	0.0101
05	Conventional	Miss;UprDvn	1.21	3.64	12.31	0.2296
05	Tight	Colr	0.57	2.15	7.96	0.0114
05	Tight	Mnvl	0.94	3.39	10.77	0.0095
06	Conventional	Tert	0.06	0.38	1.67	0.0043
06	Conventional	UprCret;UprColr	6.92	6.23	20.48	0.0153
06	Conventional	Mnvl	6.36	5.77	15.04	0.0034
06	Conventional	LwrMnvl;Jur	6.21	5.63	16.55	0.0218
06	Conventional	Miss	3.39	4.06	16.75	0.2376
06	Conventional	UprDvn	18.8	23.36	94.98	4.6315
06	Tight	Colr	4.46	4.76	14.58	0.0226
06	Tight	Mnvl	7.87	6.61	16.64	0.0939
07	Conventional	UprColr	7.08	4.86	14.08	0.0963
07	Conventional	Colr;Mnvl	0.9	1.34	4.73	0.0909
07	Conventional	Jur;Tri;Perm	0.07	0.21	1.12	0.9984
07	Conventional	Miss	1.23	1.2	3.68	1.6192
07	Conventional	UprDvn;MdlDvn	0.06	0.28	2.35	4.2066
07	Tight	UprColr;Colr	0.73	2.66	18.78	0.3842
07	Tight	Mnvl	4.66	3.96	18.57	0
07	Tight	Jur	0	0.19	1.35	0

Area	RsrcType	Resource Group	C3 barrels per marketable mmcf	C4 barrels marketable mmcf	C5+ barrels marketable mmcf	Sulphur tonnes per marketable mmcf
08	Conventional	UprColr;Colr	5.16	3.89	7.84	0.0023
08	Conventional	Mnvl;Jur	2.3	2.91	8.88	0.0199
08	Conventional	Tri	10.37	7.48	18.88	0.7438
08	Conventional	UprDvn	17.48	18.04	81.7	3.1326
08	Tight	Colr;Mnvl	11.11	6.69	11.5	0.0259
09	Conventional	UprCret	3.56	3.68	8.18	0
09	Conventional	UprColr	11.71	6.89	12.63	0.0041
09	Conventional	Mnvl;Jur	8.36	5.05	9.82	0.0559
09	Conventional	Tri	3.53	2.06	5.49	1.2427
09	Conventional	UprDvn	0.53	1.18	10.56	4.7413
09	Tight	UprColr	5.67	5.1	15	0.013
09	Tight	Colr	6.98	3.96	9.45	0.1195
09	Tight	Mnvl;Jur	8.63	4.64	8.79	0.0167
10	Conventional	Mnvl;UprDvn	0	0.01	0.04	0
11	Conventional	UprColr	0.31	0.69	2.52	0.0013
11	Conventional	Colr;UprMnvl	0.43	0.29	1.87	0.002
11	Conventional	MdlMnvl;LwrMnvl	0.16	0.45	2.96	0.0045
11	Conventional	UprTri	0.86	1.5	4.95	0.21
11	Conventional	LwrTri	0.74	2.19	9.33	0.4875
11	Conventional	Miss	5.67	4.43	11.9	0.0056
11	Conventional	UprDvn;MdlDvn	0.42	2.15	5.96	0.097
12	Conventional	Mnvl	0.09	0.44	1.39	0.0008
12	Conventional	Miss	0	0.16	0.56	0
12	Conventional	UprDvn	0.53	2.55	14.59	0.0644
12	Conventional	MdlDvn	4.77	3.48	7.51	0.5341
13	Conventional	Colr	2.65	2.31	3.44	0
13	Conventional	LwrTri	0.42	0.35	0.41	0.2479
13	Tight	Colr	0	0.26	1.07	0
13	Tight	Mnvl	0.09	0.18	0.61	0
14	Conventional	Mnvl	15.96	8.14	7.19	0.0242
14	Conventional	Tri	10.71	6.91	7.63	0.5024
14	Conventional	Perm;Miss	3.26	2.97	6.45	0.0818
14	Conventional	UprDvn;MdlDvn	0.03	0.06	4	0.0402
15	Conventional	LwrMnvl	8.27	6.74	8.05	0
15	Conventional	Perm;Miss	0.03	0.08	0.31	0.0467
15	Conventional	UprDvn;MdlDvn	0.13	0.15	0.18	0.5967
15	Tight	UprDvn	0	0.15	1.47	0.0027
16	Conventional	Colr;Mnvl	0.64	0.59	0.67	0.005
16	Conventional	Tri;Perm;Miss	0.01	0.06	0.24	2.9532
17	Tight	UprColr	0	0.1	0.39	0
18	Conventional	Colr	0.02	0.28	0.96	0.0017
18	Conventional	MdlMnvl;LwrMnvl;Miss	0.02	0.28	0.96	0.0017

Appendix 8 – Other Well Parameters

Area	Resource Type	Resource Group	Total Measured Depth m	Shrinkage % after processing	Probability of Success %
00	CBM	Main HSC	760	95.0%	100.0%
00	CBM	Mannville	1500	95.0%	100.0%
01	Conventional	Tert;UprCret;UprColr	827	95.5%	99.4%
01	Conventional	Colr	1052	95.0%	95.5%
01	Conventional	Mnvl	1201	92.2%	94.3%
01	Tight	UprColr	668	94.4%	99.8%
02	Conventional	Tert;UprCret;UprColr	1020	94.0%	99.1%
02	Conventional	Colr	1087	94.5%	60.0%
02	Conventional	MdlMnvl;LwrMnvl	1569	88.3%	93.9%
02	Conventional	Jur;Miss	2095	86.6%	100.0%
02	Conventional	UprDvn	2978	58.6%	100.0%
02	Tight	UprColr	871	95.4%	75.0%
02	Tight	Colr	1604	94.8%	75.0%
02	Tight	LwrMnvl	2360	90.9%	81.2%
03	Conventional	Miss;UprDvn	3725	63.5%	100.0%
04	Conventional	UprCret;UprColr	621	95.4%	98.5%
04	Conventional	Colr;Mnvl	807	94.7%	90.2%
04	Tight	UprColr	875	95.8%	100.0%
05	Conventional	Tert;UprCret	798	93.5%	93.0%
05	Conventional	Colr	1216	94.4%	94.2%
05	Conventional	Mnvl	1160	91.9%	81.7%
05	Conventional	Miss;UprDvn	1459	89.1%	85.7%
05	Tight	Colr	1584	92.1%	94.4%
05	Tight	Mnvl	1736	90.2%	88.2%
06	Conventional	Tert	997	90.9%	98.0%
06	Conventional	UprCret;UprColr	1611	87.2%	92.6%
06	Conventional	Mnvl	2078	86.7%	100.0%
06	Conventional	LwrMnvl;Jur	2545	84.8%	91.8%
06	Conventional	Miss	2662	84.5%	84.8%
06	Conventional	UprDvn	3337	51.5%	76.9%
06	Tight	Colr	2567	88.7%	79.3%
06	Tight	Mnvl	2383	84.4%	86.0%
07	Conventional	UprColr	2782	88.5%	73.7%
07	Conventional	Colr;Mnvl	3152	91.1%	80.0%
07	Conventional	Jur;Tri;Perm	3978	87.4%	100.0%
07	Conventional	Miss	4642	81.8%	84.6%
07	Conventional	UprDvn;MdlDvn	4179	69.3%	80.0%
07	Tight	UprColr;Colr	3138	87.9%	100.0%
07	Tight	Mnvl	3478	88.3%	100.0%
07	Tight	Jur	3666	95.7%	100.0%
08	Conventional	UprColr;Colr	1659	90.5%	75.0%
08	Conventional	Mnvl;Jur	1947	89.7%	76.8%
08	Conventional	Tri	2353	82.2%	88.4%
08	Conventional	UprDvn	2968	64.4%	83.3%
08	Tight	Colr;Mnvl	2088	84.9%	88.1%

Area	Resource Type	Resource Group	Total Measured Depth m	Shrinkage % after processing	Probability of Success %
09	Conventional	UprCret	1915	91.2%	100.0%
09	Conventional	UprColr	2407	86.2%	94.7%
09	Conventional	Mnvl;Jur	2950	84.6%	100.0%
09	Conventional	Tri	2706	84.1%	100.0%
09	Conventional	UprDvn	4174	70.1%	85.7%
09	Tight	UprColr	2505	88.7%	95.2%
09	Tight	Colr	2827	85.6%	95.7%
09	Tight	Mnvl;Jur	2997	85.3%	97.5%
10	Conventional	Mnvl;UprDvn	536	95.1%	82.7%
11	Conventional	UprColr	702	94.5%	92.9%
11	Conventional	Colr;UprMnvl	930	94.6%	72.7%
11	Conventional	MdlMnvl;LwrMnvl	1366	92.4%	67.0%
11	Conventional	UprTri	1582	90.5%	73.7%
11	Conventional	LwrTri	1981	88.7%	96.0%
11	Conventional	Miss	1803	88.8%	73.3%
11	Conventional	UprDvn;MdlDvn	1978	89.0%	85.7%
12	Conventional	Mnvl	434	94.1%	90.4%
12	Conventional	Miss	575	90.7%	88.6%
12	Conventional	UprDvn	1545	90.8%	66.7%
12	Conventional	MdlDvn	1542	84.0%	94.4%
13	Conventional	Colr	2240	95.1%	50.0%
13	Conventional	LwrTri	2934	91.7%	96.6%
13	Tight	Colr	2632	96.4%	100.0%
13	Tight	Mnvl	3001	95.2%	98.7%
14	Conventional	Mnvl	1074	85.2%	95.7%
14	Conventional	Tri	1659	85.2%	98.2%
14	Conventional	Perm;Miss	2194	91.9%	100.0%
14	Conventional	UprDvn;MdlDvn	3135	89.3%	100.0%
15	Conventional	LwrMnvl	1621	92.6%	100.0%
15	Conventional	Perm;Miss	630	89.4%	100.0%
15	Conventional	UprDvn;MdlDvn	2297	79.7%	89.5%
15	Tight	UprDvn	2318	95.3%	96.3%
16	Conventional	Colr;Mnvl	2224	90.9%	96.7%
16	Conventional	Tri;Perm;Miss	2681	78.3%	98.0%
17	Tight	UprColr	561	86.0%	100.0%
18	Conventional	Colr	690	80.0%	100.0%
18	Conventional	MdlMnvl;LwrMnvl;Miss	690	80.0%	100.0%

Appendix 9 – Formation Ratios by Grouping

Area	Resource Type	Resource Group	PetroCube Formations: Ter	Upp Cret	Upp Col	Col	Upp Mann	Mid Mann	Low Mann	Jur	Upp Tri	Low Tri	Perm	Miss	Upp Dev	Mid Dev	PreCam
00	CBM	Main HSC	CBM cost data gathered through industry consultation and NEB's briefing note 'Overview and Economics of Horseshoe Canyon														
00	CBM	Mannville	Coalbed Methane Development'														
01	Conventional	Tert;UprCret;UprColr	1%	65%	34%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
01	Conventional	Colr	0%	0%	2%	98%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
01	Conventional	Mnvl	0%	0%	1%	3%	12%	48%	36%	0%	0%	0%	0%	0%	0%	0%	0%
01	Tight	UprColr	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
02	Conventional	Tert;UprCret;UprColr	2%	87%	11%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
02	Conventional	Colr	0%	1%	5%	94%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
02	Conventional	MdlMnvl;LwrMnvl	0%	0%	0%	0%	0%	66%	33%	0%	0%	0%	0%	0%	0%	0%	0%
02	Conventional	Jur;Miss	0%	0%	0%	0%	0%	0%	0%	46%	0%	0%	0%	54%	0%	0%	0%
02	Conventional	UprDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
02	Tight	UprColr	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
02	Tight	Colr	0%	0%	5%	95%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
02	Tight	LwrMnvl	0%	0%	0%	0%	0%	2%	98%	0%	0%	0%	0%	0%	0%	0%	0%
03	Conventional	Miss;UprDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	78%	22%	0%	0%
04	Conventional	UprCret;UprColr	0%	44%	56%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
04	Conventional	Colr;Mnvl	0%	1%	0%	30%	49%	13%	7%	0%	0%	0%	0%	0%	0%	0%	0%
04	Tight	UprColr	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
05	Conventional	Tert;UprCret	15%	84%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
05	Conventional	Colr	0%	3%	1%	96%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
05	Conventional	Mnvl	0%	0%	0%	1%	18%	33%	47%	0%	0%	0%	0%	0%	0%	0%	0%
05	Conventional	Miss;UprDvn	0%	0%	0%	1%	1%	1%	2%	0%	0%	0%	0%	36%	59%	0%	0%
05	Tight	Colr	0%	0%	2%	98%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
05	Tight	Mnvl	0%	0%	0%	7%	7%	28%	59%	0%	0%	0%	0%	0%	0%	0%	0%
06	Conventional	Tert	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
06	Conventional	UprCret;UprColr	2%	36%	62%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
06	Conventional	Mnvl	0%	1%	0%	0%	1%	97%	0%	0%	0%	0%	0%	0%	0%	0%	0%
06	Conventional	LwrMnvl;Jur	0%	0%	1%	0%	0%	2%	15%	82%	0%	0%	0%	0%	0%	0%	0%
06	Conventional	Miss	0%	0%	0%	0%	0%	1%	3%	3%	0%	0%	0%	92%	0%	0%	0%
06	Conventional	UprDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
06	Tight	Colr	0%	0%	1%	99%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
06	Tight	Mnvl	0%	0%	0%	1%	4%	37%	57%	0%	0%	0%	0%	0%	0%	0%	0%
07	Conventional	UprColr	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
07	Conventional	Colr;Mnvl	0%	0%	7%	60%	12%	5%	16%	0%	0%	0%	0%	0%	0%	0%	0%
07	Conventional	Jur;Tri;Perm	0%	0%	1%	1%	0%	0%	1%	19%	38%	35%	5%	0%	0%	0%	0%
07	Conventional	Miss	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	99%	0%	0%	0%
07	Conventional	UprDvn;MdlDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	94%	3%	0%
07	Tight	UprColr;Colr	0%	0%	23%	77%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
07	Tight	Mnvl	0%	0%	8%	8%	10%	11%	63%	0%	0%	0%	0%	0%	0%	0%	0%
07	Tight	Jur	0%	0%	0%	0%	0%	0%	16%	84%	0%	0%	0%	0%	0%	0%	0%
08	Conventional	UprColr;Colr	0%	0%	69%	31%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
08	Conventional	Mnvl;Jur	0%	0%	0%	0%	7%	9%	32%	51%	0%	0%	0%	0%	0%	0%	0%
08	Conventional	Tri	0%	0%	0%	0%	0%	0%	1%	0%	13%	85%	0%	0%	0%	0%	0%
08	Conventional	UprDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
08	Tight	Colr;Mnvl	0%	0%	1%	9%	14%	16%	59%	0%	0%	0%	0%	0%	0%	0%	0%

Area	Resource Type	Resource Group	PetroCube Formations Ter	Upp Cret	Upp Col	Col	Upp Mann	Mid Mann	Low Mann	Jur	Upp Tri	Low Tri	Perm	Miss	Upp Dev	Mid Dev	PreCam
09	Conventional	UprCret	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
09	Conventional	UprColr	0%	1%	96%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
09	Conventional	Mnvl;Jur	0%	3%	4%	2%	16%	6%	27%	42%	0%	0%	0%	0%	0%	0%	0%
09	Conventional	Tri	0%	0%	0%	1%	0%	0%	8%	2%	10%	80%	0%	0%	0%	0%	0%
09	Conventional	UprDvn	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	99%	0%	0%
09	Tight	UprColr	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
09	Tight	Colr	0%	0%	5%	95%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
09	Tight	Mnvl;Jur	0%	0%	8%	6%	18%	20%	48%	1%	0%	0%	0%	0%	0%	0%	0%
10	Conventional	Mnvl;UprDvn	0%	0%	0%	0%	51%	17%	21%	0%	0%	0%	0%	0%	11%	0%	0%
11	Conventional	UprColr	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	Conventional	Colr;UprMnvl	0%	0%	0%	33%	67%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	Conventional	MdlMnvl;LwrMnvl	0%	0%	1%	0%	1%	46%	53%	0%	0%	0%	0%	0%	0%	0%	0%
11	Conventional	UprTri	0%	0%	0%	0%	0%	0%	1%	0%	99%	0%	0%	0%	0%	0%	0%
11	Conventional	LwrTri	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%
11	Conventional	Miss	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%
11	Conventional	UprDvn;MdlDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	91%	9%	0%
12	Conventional	Mnvl	0%	0%	0%	0%	9%	84%	5%	0%	0%	2%	0%	0%	0%	0%	0%
12	Conventional	Miss	0%	0%	0%	0%	0%	6%	0%	0%	0%	0%	0%	93%	0%	0%	0%
12	Conventional	UprDvn	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	99%	0%	0%
12	Conventional	MdlDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	9%	91%	0%
13	Conventional	Colr	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
13	Conventional	LwrTri	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%
13	Tight	Colr	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
13	Tight	Mnvl	0%	0%	0%	0%	14%	4%	82%	0%	0%	0%	0%	0%	0%	0%	0%
14	Conventional	Mnvl	0%	0%	0%	0%	25%	32%	43%	0%	0%	0%	0%	0%	0%	0%	0%
14	Conventional	Tri	0%	0%	0%	0%	0%	3%	4%	0%	33%	61%	0%	0%	0%	0%	0%
14	Conventional	Perm;Miss	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	63%	37%	0%	0%	0%
14	Conventional	UprDvn;MdlDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	17%	83%	0%
15	Conventional	LwrMnvl	0%	0%	0%	0%	0%	2%	95%	0%	0%	2%	0%	0%	0%	0%	0%
15	Conventional	Perm;Miss	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	98%	0%	0%	0%
15	Conventional	UprDvn;MdlDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	98%	0%
15	Tight	UprDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
16	Conventional	Colr;Mnvl	0%	0%	0%	11%	27%	21%	41%	0%	0%	0%	0%	0%	0%	0%	0%
16	Conventional	Tri;Perm;Miss	0%	0%	0%	0%	0%	0%	0%	0%	76%	4%	17%	4%	0%	0%	0%
17	Tight	UprColr	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	Conventional	Colr	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	Conventional	MdlMnvl;LwrMnvl;Miss	0%	0%	0%	0%	0%	90%	1%	0%	0%	0%	0%	9%	0%	0%	0%

Appendix 10 – 2007 Capital Costs

Area	Resource Type	Resource Group	Drill & Abandon Cost (unsuccessful well) Thousands C$	Drill & Comp Cost (successful well) Thousands C$	Tie-In Costs Thousands C$	Reclamation Costs Thousands C$	Land Costs Thousands C$
00	CBM	Main HSC	120	295	140	50	40
00	CBM	Mannville	480	1080	560	100	40
01	Conventional	02;03;04	161	262	90	40	10
01	Conventional	05	216	404	110	40	10
01	Conventional	06;07;08	305	545	120	48	10
01	Tight	04	132	217	100	40	10
02	Conventional	02;03;04	84	227	103	40	55
02	Conventional	05	223	462	103	40	55
02	Conventional	07;08	371	587	103	40	55
02	Conventional	09;13	429	696	103	45	55
02	Conventional	14	874	1264	103	50	55
02	Tight	04	115	257	103	40	55
02	Tight	05	224	464	103	40	55
02	Tight	08	356	601	103	40	55
03	Conventional	13;14	10780	13277	1550	50	494
04	Conventional	03;04	84	184	150	40	25
04	Conventional	05;06;07;08	156	386	198	40	25
04	Tight	04	99	203	160	40	25
05	Conventional	02;03	155	292	160	40	52
05	Conventional	05	357	657	201	40	52
05	Conventional	06;07;08	412	709	203	40	52
05	Conventional	13;14	691	1163	264	50	52
05	Tight	05	531	1004	202	40	52
05	Tight	06;07;08	808	1424	203	40	52
06	Conventional	02	139	276	60	40	106
06	Conventional	03;04	518	718	70	40	106
06	Conventional	06;07;08	852	1559	136	40	106
06	Conventional	08;09	972	1929	144	40	192
06	Conventional	13	1429	2535	201	58	106
06	Conventional	14	1564	2656	207	60	106
06	Tight	05	768	1323	137	40	106
06	Tight	06;07;08	896	1610	138	40	106
07	Conventional	04	1628	2403	50	35	670
07	Conventional	05;06;07;08	2320	3279	94	35	670
07	Conventional	09;10;11;12	4245	5345	98	35	670
07	Conventional	13	5954	7098	99	50	670
07	Conventional	14;15	6649	7954	131	50	670
07	Tight	04;05	2084	3003	84	35	670
07	Tight	06;07;08	2631	3611	94	35	670
07	Tight	09	4068	5182	99	35	670
08	Conventional	04;05	590	980	90	40	221
08	Conventional	06;07;08;09	931	1486	242	40	221
08	Conventional	10;11	1367	2046	412	40	221

Area	Resource Type	Resource Group	Drill & Abandon Cost (unsuccessful well) Thousands C$	Drill & Comp Cost (successful well) Thousands C$	Tie-In Costs Thousands C$	Reclamation Costs Thousands C$	Land Costs Thousands C$
08	Conventional	14	2194	3323	414	60	221
08	Tight	05;06;07;08	865	1408	205	40	221
09	Conventional	03	1121	1505	180	40	113
09	Conventional	04	1336	2146	190	40	113
09	Conventional	06;07;08;09	1774	2635	261	40	113
09	Conventional	10;11	1893	2836	399	49	113
09	Conventional	14	5639	6492	412	60	113
09	Tight	04	1238	1646	190	40	113
09	Tight	05	1271	1815	264	40	113
09	Tight	06;07;08;09	2432	3200	459	60	113
10	Conventional	06;07;08;14	190	384	150	50	12
11	Conventional	04	264	568	80	40	94
11	Conventional	05;06	330	807	206	40	94
11	Conventional	07;08	515	1028	256	40	94
11	Conventional	10	585	1360	305	50	94
11	Conventional	11	701	1515	376	50	94
11	Conventional	13	517	1252	376	60	94
11	Conventional	14;15	762	1472	376	60	94
12	Conventional	06;07;08	206	592	378	20	53
12	Conventional	13	273	743	755	20	53
12	Conventional	14	537	1042	778	50	53
12	Conventional	15	999	1452	782	50	53
13	Conventional	05	1173	1725	276	60	380
13	Conventional	11	3312	4900	700	60	380
13	Tight	05	1173	1725	376	60	380
13	Tight	06;07;08	3104	5000	700	60	380
14	Conventional	06;07;08	690	1195	400	80	250
14	Conventional	10;11	916	1730	405	80	250
14	Conventional	12;13	1494	2391	414	80	250
14	Conventional	14;15	2915	4208	430	80	250
15	Conventional	08	813	1328	276	110	240
15	Conventional	12;13	667	1195	276	110	240
15	Conventional	14;15	2483	3116	414	110	240
15	Tight	14	2590	3225	414	110	240
16	Conventional	05;06;07;08	2860	3938	264	70	1913
16	Conventional	10;11;12;13	3502	4711	356	70	1913
17	Tight	04	96	156	36	20	51
18	Conventional	05	192	384	108	30	51
18	Conventional	07;08;13	244	420	108	30	51

Appendix 11 – 2007 Operating and Processing Costs

Area	Resource Type	Resource Group	Variable Op Cost $/10^3m^3$	Variable Op Cost $/mcf	Fixed Operating Cost $/month	Processing Cost $/10^3m^3$	Processing Cost $/mcf
00	CBM	Main HSC	17.75	0.50	1000	19.52	0.55
00	CBM	Mannville	17.75	0.50	1000	19.52	0.55
01	Conventional	Tert;UprCret;UprColr	10.65	0.30	1830	14.20	0.40
01	Conventional	Colr	10.65	0.30	1942	14.20	0.40
01	Conventional	Mnvl	10.65	0.30	2067	19.27	0.54
01	Tight	UprColr	10.65	0.30	1671	14.20	0.40
02	Conventional	Tert;UprCret;UprColr	10.65	0.30	1600	26.62	0.75
02	Conventional	Colr	10.65	0.30	1600	26.62	0.75
02	Conventional	MdlMnvl;LwrMnvl	10.65	0.30	1650	26.62	0.75
02	Conventional	Jur;Miss	12.42	0.35	2100	29.46	0.83
02	Conventional	UprDvn	12.42	0.35	2100	29.46	0.83
02	Tight	UprColr	10.65	0.30	1600	26.62	0.75
02	Tight	Colr	10.65	0.30	1600	26.62	0.75
02	Tight	LwrMnvl	10.65	0.30	1650	26.62	0.75
03	Conventional	Miss;UprDvn	23.07	0.65	14417	26.62	0.75
04	Conventional	UprCret;UprColr	12.42	0.35	1533	18.74	0.53
04	Conventional	Colr;Mnvl	12.42	0.35	1725	26.13	0.74
04	Tight	UprColr	12.42	0.35	1686	19.52	0.55
05	Conventional	Tert;UprCret	8.87	0.25	1959	19.52	0.55
05	Conventional	Colr	8.87	0.25	2074	19.52	0.55
05	Conventional	Mnvl	10.65	0.30	2954	19.52	0.55
05	Conventional	Miss;UprDvn	12.42	0.35	3110	24.98	0.70
05	Tight	Colr	8.87	0.25	2076	19.52	0.55
05	Tight	Mnvl	10.65	0.30	2905	19.52	0.55
06	Conventional	Tert	10.65	0.30	2750	17.75	0.50
06	Conventional	UprCret;UprColr	10.65	0.30	2750	21.21	0.60
06	Conventional	Mnvl	15.97	0.45	2995	23.02	0.65
06	Conventional	LwrMnvl;Jur	15.97	0.45	4821	27.45	0.77
06	Conventional	Miss	19.52	0.55	5119	41.90	1.18
06	Conventional	UprDvn	19.52	0.55	5225	43.30	1.22
06	Tight	Colr	10.65	0.30	2750	21.30	0.60
06	Tight	Mnvl	15.97	0.45	2997	23.05	0.65
07	Conventional	UprColr	26.62	0.75	5842	19.52	0.55
07	Conventional	Colr;Mnvl	26.62	0.75	5872	19.52	0.55
07	Conventional	Jur;Tri;Perm	30.17	0.85	15899	22.96	0.65
07	Conventional	Miss	30.17	0.85	16406	23.07	0.65
07	Conventional	UprDvn;MdlDvn	30.17	0.85	16596	23.07	0.65
07	Tight	UprColr;Colr	26.62	0.75	5842	19.52	0.55
07	Tight	Mnvl	26.62	0.75	5919	19.52	0.55
07	Tight	Jur	30.17	0.85	14595	22.51	0.63
08	Conventional	UprColr;Colr	15.97	0.45	3250	19.52	0.55
08	Conventional	Mnvl;Jur	23.07	0.65	4652	27.47	0.77
08	Conventional	Tri	23.07	0.65	4741	28.38	0.80
08	Conventional	UprDvn	30.17	0.85	4925	28.39	0.80

Area	Resource Type	Resource Group	Variable Op Cost $\$/10^3m^3$	Variable Op Cost $/mcf	Fixed Operating Cost $/month	Processing Cost $\$/10^3m^3$	Processing Cost $/mcf
08	Tight	Colr;Mnvl	23.07	0.65	4446	25.92	0.73
09	Conventional	UprCret	26.62	0.75	4950	8.87	0.25
09	Conventional	UprColr	26.62	0.75	4950	8.87	0.25
09	Conventional	Mnvl;Jur	26.62	0.75	4758	9.63	0.27
09	Conventional	Tri	30.17	0.85	7119	10.51	0.30
09	Conventional	UprDvn	30.17	0.85	7582	19.45	0.55
09	Tight	UprColr	26.62	0.75	4750	8.87	0.25
09	Tight	Colr	26.62	0.75	4750	8.87	0.25
09	Tight	Mnvl;Jur	30.17	0.85	4779	8.90	0.25
10	Conventional	Mnvl;UprDvn	8.87	0.25	6097	27.76	0.78
11	Conventional	UprColr	10.65	0.30	4596	17.75	0.50
11	Conventional	Colr;UprMnvl	10.65	0.30	4827	17.75	0.50
11	Conventional	MdlMnvl;LwrMnvl	10.65	0.30	4921	17.75	0.50
11	Conventional	UprTri	10.65	0.30	4966	23.02	0.65
11	Conventional	LwrTri	10.65	0.30	4967	23.07	0.65
11	Conventional	Miss	10.65	0.30	5149	23.07	0.65
11	Conventional	UprDvn;MdlDvn	10.65	0.30	5500	23.07	0.65
12	Conventional	Mnvl	7.10	0.20	3142	12.59	0.35
12	Conventional	Miss	10.65	0.30	4077	22.37	0.63
12	Conventional	UprDvn	10.65	0.30	4131	22.96	0.65
12	Conventional	MdlDvn	10.65	0.30	5411	23.07	0.65
13	Conventional	Colr	21.30	0.60	6450	8.87	0.25
13	Conventional	LwrTri	21.30	0.60	6550	12.42	0.35
13	Tight	Colr	21.30	0.60	6450	8.87	0.25
13	Tight	Mnvl	21.30	0.60	6550	8.87	0.25
14	Conventional	Mnvl	15.97	0.45	4083	30.17	0.85
14	Conventional	Tri	15.97	0.45	5288	30.17	0.85
14	Conventional	Perm;Miss	15.97	0.45	5967	31.94	0.90
14	Conventional	UprDvn;MdlDvn	15.97	0.45	6150	31.94	0.90
15	Conventional	LwrMnvl	14.20	0.40	4357	19.68	0.55
15	Conventional	Perm;Miss	14.20	0.40	4650	26.62	0.75
15	Conventional	UprDvn;MdlDvn	14.20	0.40	4840	26.62	0.75
15	Tight	UprDvn	14.20	0.40	4842	26.62	0.75
16	Conventional	Colr;Mnvl	21.30	0.60	10050	15.97	0.45
16	Conventional	Tri;Perm;Miss	21.30	0.60	16839	28.40	0.80
17	Tight	UprColr	10.65	0.30	1454	17.75	0.50
18	Conventional	Colr	10.65	0.30	2004	17.75	0.50
18	Conventional	MdlMnvl;LwrMnvl;Miss	10.65	0.30	2454	24.14	0.68

Appendix 12 – 2007 Rate of Return

Rate of Return with 100% success rate

Area	Resource Type	Resource Group	Alberta NIT Gas Prices (2007C$/GJ)									Supply Cost at 15%	Payout Years
			$4 gas	$5 gas	$6 gas	$7 gas	$8 gas	$9 gas	$10 gas	$11 gas	$12 gas		
00	CBM	Main HSC	<0	0.035	0.115	0.180	0.242	0.303	0.360	0.419	0.482	$6.53	5.67
00	CBM	Mannville	0.042	0.111	0.170	0.226	0.285	0.344	0.404	0.470	0.545	$5.65	5.41
01	Conventional	Tert;UprCret;UprColr	<0	<0	<0	<0	<0	<0	0.028	0.111	0.186	$11.51	4.12
01	Conventional	Colr	<0	<0	<0	<0	<0	<0	<0	<0	<0	$14.36	3.86
01	Conventional	Mnvl	<0	<0	0.129	0.249	0.370	0.496	0.635	0.799	0.997	$6.17	4.27
01	Tight	UprColr	<0	<0	<0	<0	0.037	0.135	0.212	0.280	0.350	$9.19	4.90
02	Conventional	Tert;UprCret;UprColr	<0	<0	<0	<0	0.098	0.196	0.284	0.372	0.467	$8.53	4.54
02	Conventional	Colr	<0	<0	<0	<0	0.059	0.141	0.213	0.283	0.359	$9.12	4.02
02	Conventional	MdlMnvl;LwrMnvl	<0	0.143	0.319	0.520	0.775	1.115	1.596	2.332	3.576	$5.04	4.11
02	Conventional	Jur;Miss	<0	<0	0.001	0.095	0.177	0.254	0.330	0.415	0.510	$7.65	4.43
02	Conventional	UprDvn	0.029	0.130	0.232	0.329	0.436	0.563	0.709	0.892	1.126	$5.21	5.02
02	Tight	UprColr	<0	<0	<0	<0	<0	<0	<0	<0	<0	$20.80	4.68
02	Tight	Colr	<0	<0	<0	<0	<0	<0	<0	<0	<0	$15.69	4.29
02	Tight	LwrMnvl	0.287	0.468	0.669	0.909	1.217	1.616	2.156	2.927	4.108	$3.23	4.86
03	Conventional	Miss;UprDvn	<0	<0	0.025	0.076	0.129	0.184	0.245	0.315	0.390	$8.39	4.03
04	Conventional	UprCret;UprColr	<0	<0	<0	<0	<0	<0	<0	<0	<0	$18.46	4.62
04	Conventional	Colr;Mnvl	<0	<0	<0	0.019	0.106	0.182	0.250	0.321	0.397	$8.58	4.47
04	Tight	UprColr	<0	<0	<0	<0	<0	<0	<0	<0	<0	$18.31	5.20
05	Conventional	Tert;UprCret	<0	<0	<0	0.094	0.177	0.254	0.326	0.403	0.489	$7.67	4.97
05	Conventional	Colr	<0	<0	<0	0.003	0.062	0.110	0.153	0.195	0.239	$9.94	4.96
05	Conventional	Mnvl	<0	<0	0.047	0.150	0.245	0.340	0.439	0.552	0.682	$7.00	4.03
05	Conventional	Miss;UprDvn	<0	<0	<0	<0	<0	0.034	0.077	0.120	0.163	$11.69	4.46
05	Tight	Colr	<0	<0	0.045	0.099	0.145	0.187	0.231	0.276	0.324	$8.11	5.18
05	Tight	Mnvl	<0	<0	0.048	0.107	0.162	0.215	0.268	0.324	0.385	$7.78	4.63
06	Conventional	Tert	<0	<0	<0	0.112	0.247	0.373	0.497	0.635	0.797	$7.26	4.06
06	Conventional	UprCret;UprColr	<0	0.112	0.244	0.374	0.517	0.681	0.874	1.112	1.413	$5.28	4.18
06	Conventional	Mnvl	<0	<0	<0	<0	<0	<0	<0	<0	<0	$19.61	4.22
06	Conventional	LwrMnvl;Jur	<0	<0	<0	0.019	0.070	0.114	0.159	0.204	0.253	$9.80	4.69
06	Conventional	Miss	<0	<0	<0	0.040	0.090	0.137	0.182	0.229	0.280	$9.30	4.75
06	Conventional	UprDvn	0.794	1.319	2.168	3.609	6.346	14.308	>15	>15	>15	$2.29	4.26
06	Tight	Colr	0.108	0.195	0.277	0.358	0.445	0.538	0.640	0.757	0.894	$4.47	5.11
06	Tight	Mnvl	<0	0.022	0.090	0.148	0.206	0.263	0.322	0.388	0.461	$7.03	4.81
07	Conventional	UprColr	<0	<0	<0	0.054	0.101	0.145	0.189	0.237	0.289	$9.12	4.71
07	Conventional	Colr;Mnvl	<0	<0	0.001	0.052	0.099	0.144	0.189	0.240	0.298	$9.15	4.56
07	Conventional	Jur;Tri;Perm	0.217	0.466	0.777	1.205	1.841	2.839	4.608	8.477	>10	$3.72	4.01
07	Conventional	Miss	<0	0.087	0.168	0.249	0.339	0.437	0.561	0.717	0.902	$5.77	4.30
07	Conventional	UprDvn;MdlDvn	<0	<0	0.034	0.098	0.162	0.225	0.298	0.383	0.474	$7.81	3.79
07	Tight	UprColr;Colr	<0	<0	<0	<0	<0	0.006	0.050	0.096	0.144	$12.12	3.77
07	Tight	Mnvl	<0	<0	<0	<0	<0	<0	0.001	0.033	0.066	$14.55	3.91
07	Tight	Jur	<0	<0	<0	<0	<0	<0	0.022	0.078	0.136	$12.24	3.88

Area	Resource Type	Resource Group	Alberta NIT Gas Prices (2007C$/GJ)									Supply Cost	Payout
			$4 gas	$5 gas	$6 gas	$7 gas	$8 gas	$9 gas	$10 gas	$11 gas	$12 gas	at 15%	Years
08	Conventional	UprColr;Colr	<0	<0	<0	0.057	0.136	0.208	0.282	0.363	0.454	$8.20	4.08
08	Conventional	Mnvl;Jur	<0	<1	0.080	0.197	0.322	0.462	0.626	0.828	1.088	$6.60	3.66
08	Conventional	Tri	<0	0.013	0.095	0.168	0.245	0.328	0.421	0.529	0.662	$6.76	4.49
08	Conventional	UprDvn	0.030	0.143	0.255	0.377	0.522	0.695	0.911	1.193	1.562	$5.07	4.17
08	Tight	Colr;Mnvl	<0	<0	0.024	0.099	0.167	0.232	0.301	0.377	0.465	$7.74	4.41
09	Conventional	UprCret	<0	<0	<0	<0	<0	<0	<0	<0	0.025	$14.96	3.92
09	Conventional	UprColr	<0	<0	0.062	0.115	0.164	0.213	0.264	0.317	0.377	$7.71	4.77
09	Conventional	Mnvl;Jur	<0	<0	<0	<0	0.056	0.105	0.153	0.204	0.261	$9.94	3.96
09	Conventional	Tri	<0	<0	<0	<0	<0	0.036	0.076	0.116	0.157	$11.84	4.40
09	Conventional	UprDvn	0.219	0.475	0.856	1.481	2.639	5.299	16.831	120.150	120.150	$3.67	4.12
09	Tight	UprColr	<0	<0	0.075	0.142	0.206	0.268	0.334	0.406	0.489	$7.13	4.60
09	Tight	Colr	<0	0.123	0.251	0.388	0.554	0.758	1.020	1.373	1.872	$5.21	4.01
09	Tight	Mnvl;Jur	<0	0.063	0.126	0.187	0.252	0.323	0.401	0.496	0.610	$6.40	4.90
10	Conventional	Mnvl;UprDvn	<0	<0	<0	<0	0.004	0.149	0.268	0.392	0.522	$9.01	3.60
11	Conventional	UprColr	<0	0.203	0.414	0.642	0.916	1.262	1.720	2.364	3.331	$4.76	3.42
11	Conventional	Colr;UprMnvl	<0	0.031	0.178	0.317	0.465	0.629	0.818	1.046	1.329	$5.80	3.54
11	Conventional	MdlMnvl;LwrMnvl	<0	<0	<0	<0	0.009	0.110	0.204	0.303	0.413	$9.43	3.31
11	Conventional	UprTri	<0	<0	0.012	0.095	0.171	0.247	0.326	0.413	0.514	$7.72	4.24
11	Conventional	LwrTri	<0	<0	0.035	0.104	0.169	0.230	0.293	0.362	0.440	$7.70	4.49
11	Conventional	Miss	<0	0.036	0.146	0.247	0.354	0.469	0.599	0.753	0.943	$6.04	4.11
11	Conventional	UprDvn;MdlDvn	<0	<0	<0	<0	<0	<0	<0	<0	<0	$15.16	2.96
12	Conventional	Mnvl	<0	<0	<0	<0	0.047	0.100	0.147	0.195	0.244	$10.07	4.30
12	Conventional	Miss	<0	<0	<0	<0	<0	<0	<0	<0	<0	$19.00	3.26
12	Conventional	UprDvn	<0	<0	<0	<0	<0	<0	<0	<0	<0	$15.72	2.57
12	Conventional	MdlDvn	<0	<0	<0	<0	<0	<0	0.027	0.088	0.152	$11.97	3.26
13	Conventional	Colr	<0	<0	<0	<0	<0	<0	<0	<0	<0	$26.30	4.04
13	Conventional	LwrTri	<0	0.073	0.170	0.273	0.387	0.515	0.661	0.828	1.022	$5.80	4.08
13	Tight	Colr	0.086	0.207	0.332	0.473	0.635	0.825	1.054	1.327	1.666	$4.52	4.76
13	Tight	Mnvl	<0	0.028	0.084	0.136	0.191	0.250	0.316	0.389	0.471	$7.26	5.04
14	Conventional	Mnvl	<0	<0	<0	0.027	0.099	0.163	0.225	0.289	0.355	$8.80	4.37
14	Conventional	Tri	<0	0.062	0.156	0.247	0.344	0.452	0.574	0.712	0.872	$5.94	4.85
14	Conventional	Perm;Miss	0.017	0.205	0.408	0.656	0.970	1.379	1.931	2.712	3.903	$4.71	3.62
14	Conventional	UprDvn;MdlDvn	<0	0.080	0.196	0.317	0.450	0.602	0.777	0.981	1.221	$5.62	4.07
15	Conventional	LwrMnvl	<0	<0	<0	<0	<0	0.031	0.081	0.127	0.172	$11.49	4.49
15	Conventional	Perm;Miss	<0	<0	<0	<0	<0	<0	<0	<0	<0	$15.81	4.56
15	Conventional	UprDvn;MdlDvn	<0	<0	0.090	0.176	0.267	0.371	0.492	0.630	0.791	$6.71	4.47
15	Tight	UprDvn	<0	<0	0.008	0.066	0.120	0.174	0.229	0.286	0.347	$8.55	5.04
16	Conventional	Colr;Mnvl	<0	<0	<0	<0	<0	<0	<0	<0	0.023	$14.43	3.27
16	Conventional	Tri;Perm;Miss	<0	<0	<0	0.003	0.077	0.146	0.215	0.286	0.360	$9.06	3.92
17	Tight	UprColr	<0	<0	<0	<0	0.040	0.149	0.247	0.343	0.442	$9.01	4.13

Area	Resource Type	Resource Group	Alberta NIT Gas Prices (2007C$/GJ)									Supply Cost	Payout
			$4 gas	$5 gas	$6 gas	$7 gas	$8 gas	$9 gas	$10 gas	$11 gas	$12 gas	at 15%	Years
18	Conventional	Colr	<0	<0	<0	<0	<0	<0	<0	<0	<0	$15.40	4.04
18	Conventional	MdlMnvl;LwrMnvl;Miss	<0	<0	<0	<0	0.064	0.174	0.283	0.394	0.515	$8.78	3.48

Rate of Return with various success rates

Area	Resource Type	Resource Group	Alberta NIT Gas Prices (2007C$/GJ)									Supply Cost	Payout
			$4 gas	$5 gas	$6 gas	$7 gas	$8 gas	$9 gas	$10 gas	$11 gas	$12 gas	at 15%	Years
00	CBM	Main HSC	<0	0.035	0.115	0.180	0.242	0.303	0.360	0.419	0.482	6.53	5.67
00	CBM	Mannville	0.042	0.111	0.170	0.226	0.285	0.344	0.404	0.470	0.545	5.65	5.41
01	Conventional	Tert;UprCret;UprColr	<0	<0	<0	<0	<0	<0	0.026	0.110	0.184	11.53	4.12
01	Conventional	Colr	<0	<0	<0	<0	<0	<0	<0	<0	<0	14.58	3.89
01	Conventional	Mnvl	<0	<0	0.115	0.234	0.351	0.472	0.605	0.760	0.946	6.27	4.32
01	Tight	UprColr	<0	<0	<0	<0	0.037	0.134	0.211	0.279	0.349	9.19	4.91
02	Conventional	Tert;UprCret;UprColr	<0	<0	<0	<0	0.096	0.194	0.283	0.369	0.464	8.55	4.55
02	Conventional	Colr	<0	<0	<0	<0	<0	<0	0.067	0.126	0.185	11.41	4.28
02	Conventional	MdlMnvl;LwrMnvl	<0	0.124	0.292	0.481	0.717	1.025	1.451	2.084	3.108	5.15	4.16
02	Conventional	Jur;Miss	<0	<0	0.001	0.095	0.177	0.254	0.330	0.415	0.510	7.65	4.43
02	Conventional	UprDvn	0.029	0.130	0.232	0.329	0.436	0.563	0.709	0.892	1.126	5.21	5.02
02	Tight	UprColr	<0	<0	<0	<0	<0	<0	<0	<0	<0	22.84	4.96
02	Tight	Colr	<0	<0	<0	<0	<0	<0	<0	<0	<0	17.47	4.48
02	Tight	LwrMnvl	0.230	0.393	0.565	0.761	1.003	1.303	1.689	2.206	2.933	3.48	4.95
03	Conventional	Miss;UprDvn	<0	<0	0.025	0.076	0.129	0.184	0.245	0.315	0.390	8.39	4.03
04	Conventional	UprCret;UprColr	<0	<0	<0	<0	<0	<0	<0	<0	<0	18.53	4.63
04	Conventional	Colr;Mnvl	<0	<0	<0	0.003	0.092	0.167	0.233	0.302	0.375	8.76	4.54
04	Tight	UprColr	<0	<0	<0	<0	<0	<0	<0	<0	<0	18.31	5.20
05	Conventional	Tert;UprCret	<0	<0	<0	0.082	0.165	0.239	0.308	0.382	0.464	7.82	5.04
05	Conventional	Colr	<0	<0	<0	<0	0.053	0.101	0.142	0.184	0.228	10.18	5.00
05	Conventional	Mnvl	<0	<0	0.001	0.100	0.191	0.275	0.361	0.456	0.565	7.55	4.15
05	Conventional	Miss;UprDvn	<0	<0	<0	<0	#N/A	0.009	0.050	0.090	0.129	12.54	4.51
05	Tight	Colr	<0	<0	0.039	0.092	0.137	0.178	0.219	0.266	0.311	8.31	5.20
05	Tight	Mnvl	<0	<0	0.030	0.086	0.137	0.185	0.235	0.289	0.347	8.26	4.67
06	Conventional	Tert	<0	<0	<0	0.104	0.239	0.364	0.487	0.622	0.779	7.31	4.07
06	Conventional	UprCret;UprColr	<0	0.088	0.216	0.338	0.469	0.617	0.789	0.998	1.259	5.47	4.23
06	Conventional	Mnvl	<0	<0	<0	<0	<0	<0	<0	<0	<0	19.61	4.22
06	Conventional	LwrMnvl;Jur	<0	<0	<0	0.007	0.057	0.099	0.141	0.187	0.233	10.19	4.75
06	Conventional	Miss	<0	<0	<0	0.016	0.063	0.104	0.145	0.188	0.235	10.12	4.83
06	Conventional	UprDvn	0.617	0.999	1.548	2.350	3.571	5.764	10.810	120.150	120.150	2.50	4.34
06	Tight	Colr	0.072	0.150	0.219	0.287	0.362	0.443	0.525	0.617	0.723	4.99	5.21
06	Tight	Mnvl	<0	0.002	0.067	0.121	0.172	0.224	0.278	0.339	0.404	7.57	4.85

Area	Resource Type	Resource Group	Alberta NIT Gas Prices (2007C$/GJ)									Supply Cost	Payout
			$4 gas	$5 gas	$6 gas	$7 gas	$8 gas	$9 gas	$10 gas	$11 gas	$12 gas	at 15%	Years
07	Conventional	UprColr	<0	<0	<0	<0	0.033	0.068	0.102	0.138	0.177	11.31	4.85
07	Conventional	Colr;Mnvl	<0	<0	<0	0.005	0.045	0.082	0.119	0.161	0.205	10.74	4.72
07	Conventional	Jur;Tri;Perm	0.217	0.466	0.777	1.205	1.841	2.839	4.608	8.477	120.150	3.72	4.01
07	Conventional	Miss	<0	0.043	0.111	0.178	0.253	0.328	0.422	0.537	0.670	6.60	4.44
07	Conventional	UprDvn;MdlDvn	<0	<0	<0	0.029	0.078	0.125	0.182	0.248	0.320	9.48	3.89
07	Tight	UprColr;Colr	<0	<0	<0	<0	<0	0.006	0.050	0.096	0.144	12.12	3.77
07	Tight	Mnvl	<0	<0	<0	<0	<0	<0	0.001	0.033	0.066	14.55	3.91
07	Tight	Jur	<0	<0	<0	<0	<0	<0	0.022	0.078	0.136	12.24	3.88
08	Conventional	UprColr;Colr	<0	<0	<0	<0	0.049	0.112	0.172	0.237	0.305	9.64	4.18
08	Conventional	Mnvl;Jur	<0	<0	0.004	0.106	0.200	0.316	0.435	0.575	0.746	7.41	3.76
08	Conventional	Tri	<0	<0	0.070	0.140	0.210	0.284	0.364	0.459	0.572	7.14	4.53
08	Conventional	UprDvn	<0	0.095	0.192	0.295	0.412	0.547	0.708	0.913	1.169	5.56	4.23
08	Tight	Colr;Mnvl	<0	<0	0.001	0.072	0.136	0.198	0.259	0.327	0.404	8.23	4.46
09	Conventional	UprCret	<0	<0	<0	<0	<0	<0	<0	<0	0.025	14.96	3.92
09	Conventional	UprColr	<0	<0	0.053	0.105	0.153	0.200	0.248	0.302	0.358	7.94	4.78
09	Conventional	Mnvl;Jur	<0	<0	<0	<0	0.056	0.105	0.153	0.204	0.261	9.94	3.96
09	Conventional	Tri	<0	<0	<0	<0	<0	0.036	0.076	0.116	0.157	11.84	4.40
09	Conventional	UprDvn	0.156	0.365	0.652	1.089	1.810	3.137	6.237	120.150	120.150	3.97	4.16
09	Tight	UprColr	<0	<0	0.065	0.129	0.191	0.253	0.315	0.384	0.463	7.33	4.62
09	Tight	Colr	<0	0.110	0.233	0.364	0.521	0.711	0.953	1.274	1.721	5.33	4.02
09	Tight	Mnvl;Jur	<0	0.058	0.121	0.180	0.244	0.312	0.388	0.480	0.589	6.50	4.91
10	Conventional	Mnvl;UprDvn	<0	<0	<0	<0	<0	0.097	0.213	0.332	0.451	9.44	3.71
11	Conventional	UprColr	<0	0.180	0.382	0.598	0.854	1.170	1.583	2.149	2.976	4.86	3.45
11	Conventional	Colr;UprMnvl	<0	<0	0.098	0.225	0.349	0.481	0.626	0.797	1.002	6.41	3.67
11	Conventional	MdlMnvl;LwrMnvl	<0	<0	<0	<0	<0	<0	0.071	0.152	0.235	10.98	3.44
11	Conventional	UprTri	<0	<0	<0	0.042	0.112	0.180	0.247	0.319	0.400	8.56	4.34
11	Conventional	LwrTri	<0	<0	0.029	0.098	0.162	0.222	0.284	0.352	0.428	7.81	4.51
11	Conventional	Miss	<0	<0	0.089	0.185	0.277	0.372	0.476	0.596	0.740	6.63	4.24
11	Conventional	UprDvn;MdlDvn	<0	<0	<0	<0	<0	<0	<0	<0	<0	15.97	3.00
12	Conventional	Mnvl	<0	<0	<0	<0	0.037	0.091	0.137	0.184	0.231	10.29	4.33
12	Conventional	Miss	<0	<0	<0	<0	<0	<0	<0	<0	<0	19.38	3.29
12	Conventional	UprDvn	<0	<0	<0	<0	<0	<0	<0	<0	<0	17.62	2.71
12	Conventional	MdlDvn	<0	<0	<0	<0	<0	<0	<0	<0	0.136	12.23	3.27
13	Conventional	Colr	<0	<0	<0	<0	<0	<0	<0	<0	<0	40.22	4.23
13	Conventional	LwrTri	<0	0.065	0.161	0.261	0.372	0.495	0.635	0.746	0.981	5.89	4.09
13	Tight	Colr	0.086	0.207	0.332	0.473	0.635	0.825	1.054	1.327	1.666	4.52	4.76
13	Tight	Mnvl	<0	0.027	0.082	0.134	0.189	0.247	0.312	0.384	0.464	7.30	5.04

Area	Resource Type	Resource Group	Alberta NIT Gas Prices (2007C$/GJ)									Supply Cost	Payout
			$4 gas	$5 gas	$6 gas	$7 gas	$8 gas	$9 gas	$10 gas	$11 gas	$12 gas	at 15%	Years
14	Conventional	Mnvl	<0	<0	<0	0.019	0.090	0.154	0.215	0.277	0.342	8.93	4.39
14	Conventional	Tri	<0	0.059	0.153	0.243	0.339	0.446	0.565	0.702	0.859	5.97	4.86
14	Conventional	Perm;Miss	0.017	0.205	0.408	0.656	0.970	1.379	1.931	2.712	3.903	4.71	3.62
14	Conventional	UprDvn;MdlDvn	<0	0.080	0.196	0.317	0.450	0.602	0.777	0.981	1.221	5.62	4.07
15	Conventional	LwrMnvl	<0	<0	<0	<0	<0	0.031	0.081	0.127	0.172	11.49	4.49
15	Conventional	Perm;Miss	<0	<0	<0	<0	<0	<0	<0	<0	<0	15.81	4.56
15	Conventional	UprDvn;MdlDvn	<0	<0	0.061	0.141	0.226	0.318	0.422	0.541	0.679	7.11	4.53
15	Tight	UprDvn	<0	<0	0.001	0.059	0.111	0.164	0.218	0.273	0.332	8.74	5.05
16	Conventional	Colr;Mnvl	<0	<0	<0	<0	<0	<0	<0	<0	0.011	14.73	3.28
16	Conventional	Tri;Perm;Miss	<0	<0	<0	<0	0.071	0.139	0.207	0.276	0.348	9.16	3.93
17	Tight	UprColr	<0	<0	<0	<0	0.040	0.149	0.247	0.343	0.442	9.01	4.13
18	Conventional	Colr	<0	<0	<0	<0	<0	<0	<0	<0	<0	15.40	4.04
18	Conventional	MdlMnvl;LwrMnvl;Miss	<0	<0	<0	<0	0.064	0.174	0.283	0.394	0.515	8.78	3.48