National Energy Board

Office national de l'énergie

Energy Briefing Note

Natural Gas Supply Costs in Western Canada in 2009

gas

November 2010

Canada

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LIST OF ACRONYMS AND ABBREVIATIONS

Alberta NIT	Alberta NOVA Inventory Transfer
CBM	Coalbed Methane
CPI	Consumer Price Index
HSC	Horseshoe Canyon
NEB	National Energy Board
NCF	Net Cash Flow
NGLs	natural gas liquids
NPV	Net Present Value
ROR	Rate of Return

LIST OF UNITS AND CONVERSION FACTORS

Units

m^3	= cubic metres
MMcf	= million cubic feet
Bcf	= billion cubic feet
m^3/d	= cubic metres per day
$10^3 m^3/d$	= thousand cubic metres per day
MMcf/d	= million cubic feet per day
Bcf/d	= billion cubic feet per day
GJ	= gigajoule

Common Natural Gas Conversion Factors

1 million m^3 (@ 101.325 kPaa and 15° C) = 35.3 MMcf (@ 14.73 psia and 60° F)
1 GJ (Gigajoule) = .95 Mcf (thousand cubic feet) = .95 MMBtu = .95 decatherms

Price Notation

Canadian natural gas prices are quoted as the Alberta NIT Gas Reference Price and are listed in \$C/GJ.

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Foreword

The National Energy Board (the Board) is an independent federal organization established in 1959 to promote safety and security, environmental protection and economic efficiency in the Canadian public interest[1] within the mandate set by Parliament for the regulation of pipelines, energy development and trade.

The Board's main responsibilities include regulating the construction, operation and abandonment of interprovincial and international oil and gas pipelines, international power lines, and designated interprovincial power lines. Furthermore, the Board regulates the tolls and tariffs for the pipelines under its jurisdiction. With respect to the specific energy commodities, the Board regulates the export of natural gas, oil, natural gas liquids (NGLs) and electricity, and the import of natural gas. Additionally, the Board regulates oil and gas exploration and development on frontier lands and offshore areas not covered by provincial or federal management agreements.

In an advisory function, the Board reviews and analyzes matters related to its jurisdiction and provides information and advice on aspects of energy supply, transmission and disposition. In this role, the NEB publishes periodic assessments to inform Canadians on trends, events, and issues that may affect Canadian energy markets.

This report is an energy briefing note – a brief report covering one aspect of energy commodities. This report analyzes the supply costs of developing natural gas in Western Canada in 2009. It is the second edition covering this topic, following the 2007 supply cost report released in August 2008.[2]

In preparing this report, the NEB gained valuable feedback on well inputs, specifically cost information, from various producers. The NEB appreciates the information and comments provided and would like to thank all participants for their time and expertise.

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.

This report does not offer an opinion on the public interest for any applications. The Board evaluates each application based solely on the material before it at the time of submission.

1 The public interest is inclusive of all Canadians and refers to a balance of economic, environmental, and social interests that change as society's values and preferences evolve over time. As a regulator, the Board weighs the relevant impacts on these interests when making its decisions.

2 This report is available at http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/ntrlgsspplcstwstrncnd2007_2008/ntrlgsspplcstwstrncnd-eng.html.

Overview

This report analyses the average supply costs to producers for the production of gas from new wells drilled in 2009 in Western Canada. This report does not address production from existing facilities. Specific cases, such as long term gas processing arrangements or use of existing infrastructure, will have economics that vary from this analysis. Results in this report provide a useful indicator of whether gas production would be expected to increase or decrease in certain regions under 2009 market conditions.

The average supply cost[3] for new natural gas production in Western Canada in 2009 declined since 2007, but not as much as the average gas price declined. The average price of natural gas in Western Canada in 2009 was $3.76/GJ, lower than the 2007 average price of $6.11/GJ. This was positive news for gas consumers, negative news for gas producers. The Western Canada average natural gas supply cost for new production decreased from $7.88/GJ in 2007 to $6.97/GJ in 2009, which shows that, on average, new natural gas wells drilled in 2009 were not economic, and at current price levels would not be able to recover their full costs over the producing lifetime of the well. However, there was a wide disparity of supply costs and for some key plays, economics were more positive. Overall, tight gas, shale gas, and deeper conventional gas had the lowest supply costs. Shallow conventional gas plays had higher supply costs. As a result, the majority of industry activity focused on plays with better economics.

On an energy equivalency basis, the price of oil[4] in 2009 was almost three times the price of gas. This provided a strong incentive for energy industry investment to move from natural gas to oil development. The share of gas-directed drilling fell to less than 50 per cent in Western Canada, from what had historically been over 60 per cent. The liquids often found in natural gas, including propane, butane and pentanes plus tend to track the price of oil. In some cases, this boosted earnings for natural gas producers who had natural gas liquids (NGL) content in their gas production. Natural gas producers increasingly focused on resources with higher NGL contents, such as the Montney tight gas play. The trend to focus on liquids-rich gas reserves has continued into 2010 in both Canada and the U.S.A.

Despite higher oil prices and gas prices below average supply costs in 2009, drilling aimed at gas has continued. Some producers need revenues (cash flow) to continue to operate. Some producers looked beyond 2009 at future gas prices with expectations that natural gas prices might rise. Some producers had production hedged at prices higher than the market price. Some had lower marginal costs due to existing land holdings or infrastructure such as piping systems for gathering the gas from wells or gas processing plants. And, finally, some smaller companies continued to drill in the shallow gas and coalbed methane (CBM) plays, since they don't have budgets to drill the costlier, deeper wells[5]. Most of the gas produced in 2009 was from wells drilled before 2009. As long as producers can cover their ongoing costs, they will continue to produce gas. If prices fall below operating costs of particular wells, some producers may choose

[3] The supply cost is the minimum price required to produce a gigajoule (GJ) of natural gas, covering all costs, royalties, and taxes and includes a 15 per cent rate of return (ROR) after tax.

[4] Edmonton par price, averaged $10.82/GJ ($66.20/barrel) in 2009.

[5] Some also have expertise or existing land positions from which they may benefit.

to shut in a portion of their production, as happened in September 2009 and again in September 2010.

An overview of the regions and groupings used in this analysis, a summary of the economic methodology used to calculate the supply costs, and results of the economic analysis are included in this report. The Appendices include a detailed methodology description, data on the regions and groupings, input assumptions, and additional results.

Methodology

Natural gas comes from a wide variety of geological depths and formations, and can come from either conventional or unconventional sources that all have very different costs. In this study, Western Canada[6,7] was split geographically and geologically based on categories specifically selected to reflect areas with similar costs and production parameters, resulting in 88 groupings in total. The modified[8] regional breakdown is shown in Figure 1. The four resource types analyzed in this study were conventional, tight, shale, and CBM. Additional details, including the reasoning behind the selection of these classifications, and the methods used to generate the resulting inputs, are included in Appendix 2.

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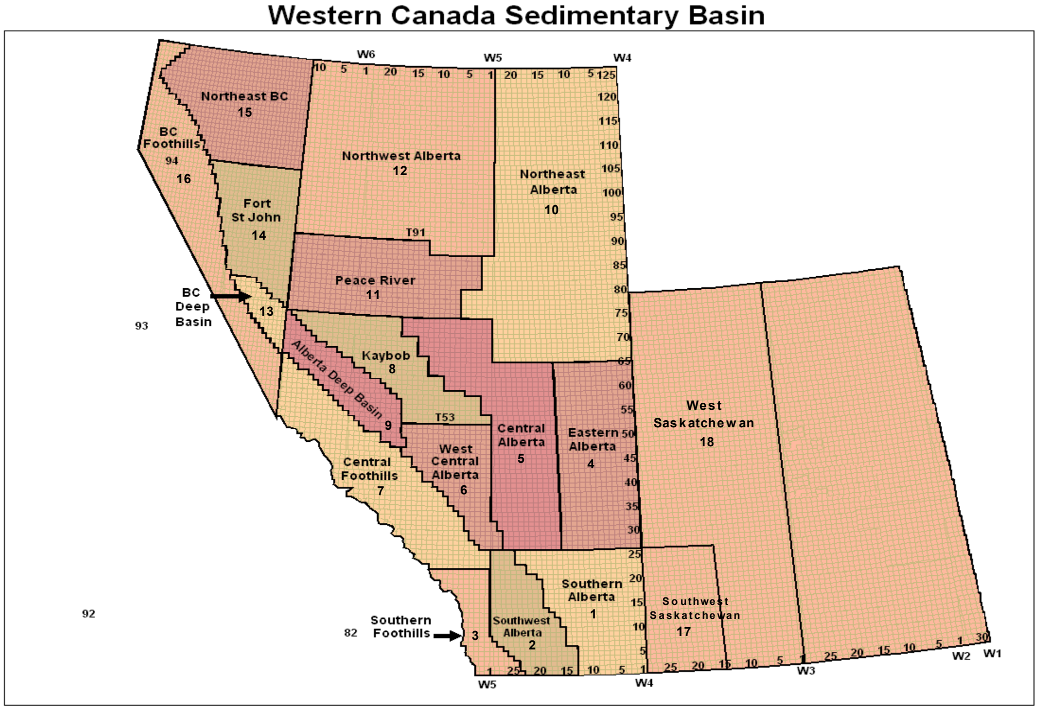
6 These classifications are developed by a petroCUBE information service that provides well cost and performance data.

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

8 Saskatchewan, under petroCUBE, was considered one whole region. For this study, the province was split into two gas-producing regions – West Saskatchewan and Southwest Saskatchewan. Eastern Saskatchewan did not have gas wells drilled in 2009 (it is an oil producing region) and is thus left out of this study.

Figure 1: Regional Map



Source: petroCUBE

For an average well in each grouping, specific parameters were estimated, including: initial production rate, production decline curve conditions, average depth, gas composition, shrinkage, and success rate. Cost data obtained from petroCUBE, supplemented by publicly available information and consultations with industry, was calculated for the average well by region and formation. Additional details on the categories and cost inputs are given in Appendix 2.

For a gas well to be economic, total revenue from the production (less operating costs, royalties, taxes and a rate of return - ROR) has to offset the upfront costs (capital and land costs). Supply costs were calculated for wells without risk (assuming a well drilled will produce at the expected rate) and with risk (accounting for the chance that a well will be unsuccessful; that is, no hydrocarbons are found, the well is abandoned, and the land is reclaimed). The success rates are shown in Table 1.

For an average well in each grouping,[9] monthly cash flows were calculated over the producing lifetime of the well.[10] Cash flow represents the revenues[11] earned less expenses incurred over the life of each well. Expenses include capital, land, operating and processing, and reclamation

[9] In this study, we used average numbers which aggregate the performance of thousands of wells. Every producing company is in a different position with respect to their own land holdings, cost structure, infrastructure, and experience.

[10] Production is assumed to stop in the first month that revenues are less than the ongoing expenses (operating and processing costs, royalties, and taxes).

[11] Revenues from natural gas (methane) as well as from NGLs (propane, butane, and pentanes plus).

costs. Royalties and taxes as they existed in 2009 were included. A 15 per cent rate of return to warrant investment was also included.[12]

The price level that generates sufficient revenue to offset the total expenses plus a return on investment establishes the supply cost for that resource grouping. This analysis is undertaken assuming that only successful wells were drilled (un-risked case), in addition to incorporating the costs of unsuccessful wells (risked case),[13] and sensitivities such as gas prices or capital cost changes. Additional details on the economic methodology used in the analysis are in Appendix 3.

Results

Supply Costs

Table 1 lists the supply costs and payout periods[14] for each resource grouping. The majority of gas production from wells drilled in 2009 came from resource groupings that have sufficient production history to model the decline curve parameters. In a few groupings, there was not enough data (either there were not enough producing wells or it was a new grouping) to determine the historical production profiles. 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 'groupings with estimated decline curves'.

The weighted average[15] supply cost with a 100 per cent success rate (un-risked) for Western Canada was \$6.81/GJ (Alberta Nova Inventory Transfer (NIT), Canadian dollars). Using 2009 success rates, the risked weighted average supply cost was \$6.97/GJ. Success rates in Western Canada development wells are relatively high (weighted average of 96 per cent success in 2009) due to the advanced stage of development of many of these resources.[16] As a result, risked supply costs are generally not significantly higher than the un-risked versions. Figure 2 includes the risked and un-risked average supply costs for each area.

Given the \$3.76/GJ average daily Alberta NIT price and an average supply cost of \$6.97/GJ, on average, new gas development was uneconomic in 2009. However, some groupings did yield positive returns. These results are consistent with general impressions expressed by industry and are evident in the shift of gas activity away from conventional shallow gas sources towards the deep drilling of tight gas and shale gas plays in Alberta and British Columbia. The 2009 average supply cost for Alberta was \$7.28/GJ, \$5.96/GJ for B.C., and \$12.87/GJ for Saskatchewan. In 2007, the B.C. and Alberta averages were almost equal at \$7.81 and \$7.84, respectively; Saskatchewan's average supply cost was \$9.53. Saskatchewan experienced higher costs as increasing activity in Saskatchewan's Bakken and Shaunavon oil plays drove average land costs higher. The industry in Saskatchewan focuses on oil production and gas operations do not benefit from scale efficiencies.

12 This 15 per cent after-tax rate translates into a higher ROR before tax.

13 See Appendix A2.3.3.

14 Payout occurs when the cumulative sum of discounted cash flows, starting in the first period, equals zero.

15 Production in 2009 from 2009 drilled development wells by grouping is used to calculate the weighted averages.

16 Exploration, test, disposal, and water wells are not included in the analysis since there is limited cost data available.

The average natural gas supply cost in 2007 was $7.88/GJ, higher than the average market price of $6.11/GJ. The decrease in the average supply cost over the two years is mainly due to an increase in the average production rate per well, from an average initial production rate of 0.92 MMcf/d to 1.52 MMcf/d. This increased production rate overshadowed an increase in the capital cost of the average well, from $2.02 million/well in 2007 to $2.46 million/well in 2009. The increase in the average production rate and average capital cost in Western Canada was largely driven by Alberta tight gas development and Northeast B.C. plays in 2009, including the Montney tight gas and Horn River shale gas plays. Wells in these plays had high capital costs of more than $5 million/well but also had high producing rates, from 3.5 MMcf/d and up. The average supply cost for the Montney tight gas in the Fort St. John area was $3.92/GJ and the average supply cost for the Horn River shale gas in Northeast B.C. was $4.68/GJ.

Changes in operating and processing costs between 2007 and 2009 mostly cancelled each other out. The average operating costs decreased from $0.50/GJ in 2007 to $0.43/GJ in 2009 whereas the average processing costs increased from $0.52/GJ in 2007 to $0.62/GJ in 2009. The processing cost increases were driven by increased production from plays with high NGL content and associated processing costs, like the Montney play in the Fort St. John area. The lower operating costs were due, in part, to lower fuel and power costs. Drilling and service costs declined since 2007 as activity slowed and drillers were under pressure to cut service rates in an increasingly competitive market. Drilling efficiency improvements also reduced drilling costs. Other input costs, such as fuel, retreated from 2007 peaks, whereas material costs like casing and tubing costs, transportation and equipment rental costs increased since 2007. Overall, capital costs per well were higher because the average well in 2009 was deeper and more complex, as horizontal lengths were drilled from vertical holes.

Table 1: 2009 Supply Costs and Payouts for each Grouping

Main Groupings:

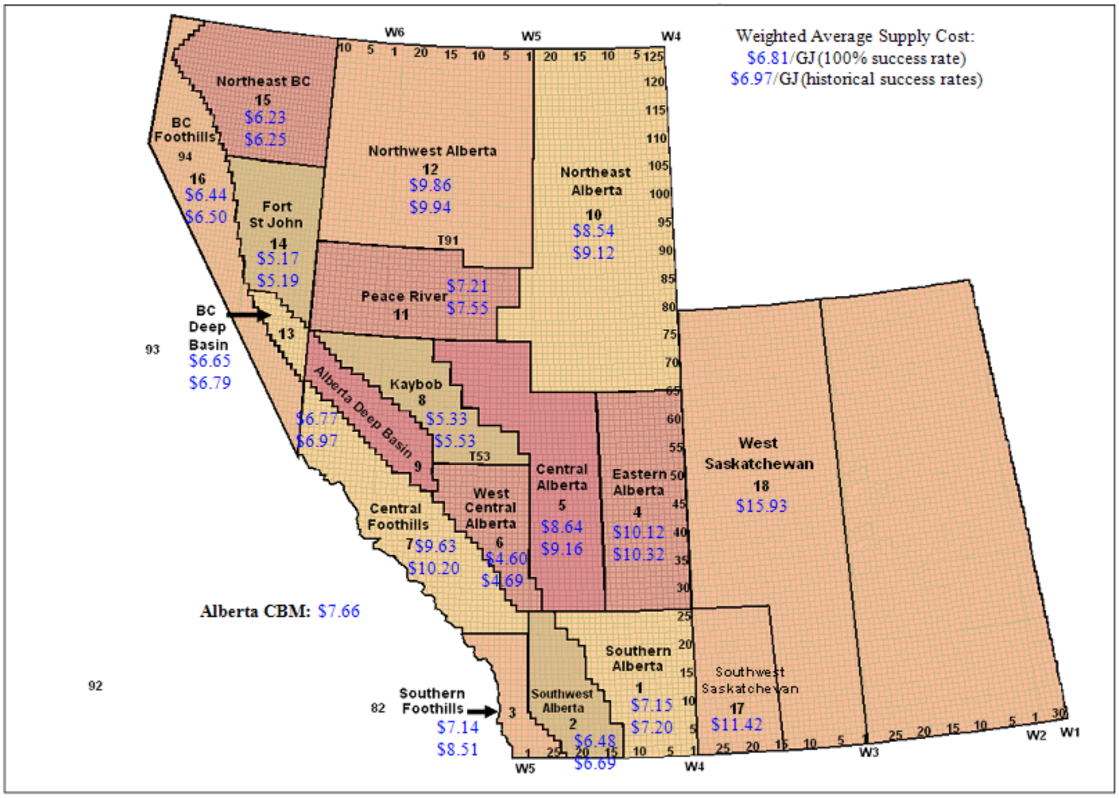
Area	Resource Type	Resource Group	100% Success Rate (un-risked) Supply Cost Alberta NIT C$/GJ	100% Success Rate (un-risked) Payout years	Historical Success Rates (risked) Supply Cost Alberta NIT C$/GJ	Historical Success Rates (risked) Payout years	Historical Success Rates (risked) Success Rate %	2009 Wells Production Bcf	2009 Wells Prod'n Rank
00 - AB CBM	CBM	Mannville	$6.31	5.26	$6.31	5.26	100.0%	1.56	44
00 - AB CBM	CBM	Main HSC	$7.75	6.04	$7.75	6.04	100.0%	22.37	4
01 - Southern AB	Conventional	Tert;UprCret;UprColr	$5.86	5.29	$5.86	5.29	99.9%	3.39	30
01 - Southern AB	Conventional	Colr	$10.05	4.55	$10.34	4.60	93.5%	1.17	53
01 - Southern AB	Conventional	Mnvl	$5.44	5.09	$5.65	5.19	90.0%	5.07	24
01 - Southern AB	Tight	UprColr	$7.65	5.25	$7.66	5.25	99.6%	19.08	5
02 - Southwest AB	Conventional	Tert;UprCret;UprColr	$8.39	6.10	$8.52	6.19	95.5%	1.41	48
02 - Southwest AB	Conventional	MdlMnvl;LwrMnvl	$4.45	4.81	$4.50	4.85	97.0%	1.60	43
02 - Southwest AB	Tight	UprColr	$6.47	6.12	$6.47	6.13	99.9%	0.12	76
04 - Eastern AB	Conventional	UprCret;UprColr	$14.39	4.89	$14.57	4.93	96.0%	0.43	67
04 - Eastern AB	Conventional	Colr;Mnvl	$9.83	4.36	$10.03	4.40	95.0%	8.49	15
04 - Eastern AB	Tight	UprColr	$23.47	5.35	$24.21	5.44	90.0%	0.04	81
05 - Central AB	Conventional	Tert;UprCret	$8.77	4.48	$8.79	4.49	99.0%	3.39	31
05 - Central AB	Conventional	Colr	$9.38	5.36	$9.43	5.37	98.0%	0.68	62
05 - Central AB	Conventional	Mnvl	$8.39	4.17	$9.25	4.44	78.0%	8.04	16
05 - Central AB	Conventional	Miss;UprDvn	$11.90	4.93	$12.31	4.99	93.0%	0.85	57
05 - Central AB	Tight	Colr	$10.85	5.36	$10.86	5.36	99.9%	0.73	60
05 - Central AB	Tight	Mnvl	$3.23	5.47	$3.29	5.56	92.3%	0.61	63
06 - West Central AB	Conventional	Tert	$4.33	4.45	$4.37	4.48	97.0%	4.13	27
06 - West Central AB	Conventional	UprCret;UprColr	$3.68	4.94	$3.76	5.14	91.0%	3.12	33
06 - West Central AB	Conventional	LwrMnvl;Jur	$4.57	4.86	$4.65	4.90	93.0%	9.68	12
06 - West Central AB	Tight	Mnvl	$4.61	5.10	$4.67	5.14	95.3%	12.40	9
07 - Central Foothills	Conventional	Colr;Mnvl	$11.33	4.88	$11.47	4.89	97.0%	8.66	14
07 - Central Foothills	Conventional	Miss	$9.04	3.74	$10.34	3.79	81.0%	7.56	17
07 - Central Foothills	Conventional	UprDvn;MdlDvn	$16.07	3.99	$16.07	3.99	100.0%	0.07	79
08 - Kaybob	Conventional	UprColr;Colr	$4.90	4.86	$5.97	5.16	66.7%	1.02	56
08 - Kaybob	Conventional	Mnvl;Jur	$5.71	4.37	$5.93	4.45	91.7%	5.59	22
08 - Kaybob	Conventional	Tri	$4.76	4.80	$4.87	4.84	94.7%	9.95	11
08 - Kaybob	Tight	Colr;Mnvl	$6.16	4.37	$6.37	4.42	92.9%	6.12	19
09 - AB Deep Basin	Conventional	UprCret	$10.72	4.90	$11.24	4.92	92.0%	1.22	52
09 - AB Deep Basin	Conventional	UprColr	$7.93	4.45	$8.02	4.48	97.8%	1.82	41
09 - AB Deep Basin	Conventional	Mnvl;Jur	$11.93	4.94	$11.93	4.94	100.0%	3.41	29
09 - AB Deep Basin	Conventional	Tri	$13.31	4.48	$13.31	4.48	100.0%	4.00	28
09 - AB Deep Basin	Tight	UprColr	$10.91	5.14	$11.03	5.15	97.8%	6.56	18
09 - AB Deep Basin	Tight	Mnvl;Jur	$5.62	5.17	$5.84	5.20	94.1%	63.58	1
10 - Northeast AB	Conventional	Mnvl;UprDvn	$8.54	4.17	$9.12	4.33	81.1%	5.16	23
11 - Peace River	Conventional	UprColr	$15.69	4.38	$17.79	4.54	76.0%	0.06	80
11 - Peace River	Conventional	Colr;UprMnvl	$12.02	3.76	$13.38	3.89	80.0%	0.60	64
11 - Peace River	Conventional	MdlMnvl;LwrMnvl	$11.53	4.40	$13.23	4.50	78.8%	2.20	37
11 - Peace River	Conventional	LwrTri	$6.21	4.70	$6.24	4.72	99.0%	13.83	7
12 - Northwest AB	Conventional	MdlDvn	$11.74	4.21	$11.74	4.21	100.0%	2.89	34
13 - BC Deep Basin	Conventional	LwrTri	$6.01	4.26	$6.09	4.26	98.3%	12.77	8
13 - BC Deep Basin	Tight	Mnvl	$6.95	4.88	$6.98	4.89	99.3%	12.20	10
13 - BC Deep Basin	Tight	LwrTri	$8.36	4.39	$8.36	4.39	100.0%	1.30	51
14 - Fort St. John	Conventional	Mnvl	$10.07	5.03	$10.17	5.03	98.0%	4.60	25
14 - Fort St. John	Conventional	Tri	$5.14	4.99	$5.15	5.01	99.1%	30.74	3
14 - Fort St. John	Tight	Tri	$3.92	4.94	$3.92	4.94	100.0%	14.86	6
15 - Northeast BC	Tight	UprDvn	$18.24	4.87	$18.49	4.88	98.1%	4.25	26
16 - BC Foothills	Conventional	Colr;Mnvl	$9.32	4.58	$9.42	4.59	98.4%	5.59	21
17 - Southwest SK	Tight	UprColr	$11.42	4.98	$11.42	4.98	100.0%	5.78	20
18 - Western SK	Conventional	Colr	$23.75	4.66	$23.75	4.66	100.0%	1.38	49
18 - Western SK	Conventional	MdlMnvl;LwrMnvl;Miss	$7.92	4.65	$7.92	4.65	100.0%	1.35	50
Production-Weighted Averages (and Total Production):			**$7.09**	**4.92**	**$7.25**	**4.96**	**95.7%**	**347.49**	**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 estimated decline curves (hard to model production profile based on history) or newly developed groupings (not a lot of 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	Colr	$5.81	5.89	$7.20	4.28	62.5%	0.32	69
02 - Southwest AB	Conventional	Jur;Miss	$10.31	5.21	$10.31	5.21	100.0%	0.17	72
02 - Southwest AB	Tight	Colr	$6.01	5.62	$7.30	5.99	65.0%	0.15	75
02 - Southwest AB	Tight	LwrMnvl	$6.88	4.78	$6.88	4.79	99.9%	0.51	65
03 - Southern Foothills	Conventional	Miss;UprDvn	$7.14	4.21	$8.51	4.25	80.0%	0.10	78
06 - West Central AB	Conventional	Mnvl	$3.88	4.17	$3.88	4.17	100.0%	0.12	77
06 - West Central AB	Conventional	Miss	$5.75	4.67	$5.84	4.71	95.0%	1.93	40
06 - West Central AB	Conventional	UprDvn	$6.03	2.77	$6.73	2.99	75.0%	1.55	45
06 - West Central AB	Tight	Colr	$3.68	5.28	$3.77	5.28	91.7%	0.36	68
07 - Central Foothills	Conventional	UprColr	$6.79	4.97	$7.70	5.06	75.0%	2.04	39
07 - Central Foothills	Conventional	Jur;Tri;Perm	$9.01	4.72	$9.07	4.72	99.0%	1.74	42
07 - Central Foothills	Tight	UprColr;Colr	$9.42	4.92	$9.42	4.92	100.0%	0.28	70
07 - Central Foothills	Tight	Jur	$8.08	4.52	$8.08	4.52	100.0%	2.45	36
08 - Kaybob	Conventional	UprDvn	$4.61	4.67	$4.76	4.78	93.0%	1.48	47
09 - AB Deep Basin	Conventional	UprDvn	$3.45	4.43	$4.12	4.57	75.0%	1.14	54
09 - AB Deep Basin	Tight	Colr	$6.45	5.01	$6.81	5.07	92.0%	3.38	32
11 - Peace River	Conventional	UprTri	$7.74	4.53	$7.92	4.56	96.0%	0.49	66
11 - Peace River	Conventional	Miss	$5.80	4.58	$5.80	4.58	100.0%	2.62	35
11 - Peace River	Conventional	UprDvn;MdlDvn	$26.33	4.23	$34.92	4.42	62.5%	0.21	71
11 - Peace River	Tight	UprColr	$11.86	4.54	$12.10	4.59	95.0%	0.04	82.00
11 - Peace River	Tight	MdlMnvl;LwrMnvl	$14.90	4.44	$15.40	4.45	95.0%	0.01	86.00
12 - Northwest AB	Conventional	Mnvl	$7.18	4.33	$7.18	4.33	100.0%	0.83	58
12 - Northwest AB	Conventional	Miss	$20.44	4.37	$20.44	4.37	100.0%	0.16	74
12 - Northwest AB	Conventional	UprDvn	$6.62	3.98	$6.93	4.08	87.5%	1.50	46
13 - BC Deep Basin	Conventional	Colr	$18.40	4.81	$32.10	5.05	50.0%	0.16	73
13 - BC Deep Basin	Tight	Colr	$7.32	4.92	$7.32	4.92	100.0%	0.70	61
14 - Fort St. John	Conventional	Perm;Miss	$4.11	4.26	$4.11	4.26	100.0%	2.18	38
14 - Fort St. John	Conventional	UprDvn;MdlDvn	$3.62	4.22	$3.62	4.22	100.0%	1.14	55
14 - Fort St. John	Tight	Perm;Miss	$6.69	4.83	$6.69	4.83	100.0%	0.73	59.00
15 - Northeast BC	Conventional	LwrMnvl	$25.49	5.54	$25.49	5.54	100.0%	0.01	85
15 - Northeast BC	Conventional	Perm;Miss	$13.90	4.96	$13.90	4.96	100.0%	0.03	83
15 - Northeast BC	Conventional	UprDvn;MdlDvn	$13.35	4.99	$13.81	5.01	95.0%	0.02	84
15 - Northeast BC	Shale	MdlDvn	$4.68	5.73	$4.68	5.73	100.0%	33.47	2
16 - BC Foothills	Conventional	Tri;Perm;Miss	$4.72	5.08	$4.75	5.08	99.0%	9.38	13
Production-Weighted Averages (and Total Production):			**$5.43**	**5.17**	**$5.59**	**5.18**	**96.7%**	**71.41**	**21**

Figure 2: Average 2009 Supply Costs by Region



Price and Capital Cost Sensitivities

Sensitivity tests were performed on the six groupings with the highest new production totals in 2009. These top six groupings represent a wide variety of locations, including shallow and deep wells, and all four gas resource types.

To calculate supply cost sensitivities with gas price, the ROR is calculated for an assumed range of gas prices, from $3 to $12/GJ Alberta NIT. Figure 3 shows that at gas prices of $4/GJ, the deeper conventional, tight and shale groupings earn returns above zero whereas the shallow and CBM groupings need more than $6/GJ to earn positive returns. Gas price sensitivities for all groupings are in Appendix 12.

Figure 4 illustrates how supply costs change if total capital costs[17] increase or decrease by 25 per cent for the six groupings.[18] Some groupings were slightly more sensitive to capital cost changes

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17 Well drilling, tie-in, land, and reclamation costs.

18 Note that the sensitivity examples are un-risked. 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, the Fort St. John tight grouping and the Northeast B.C. shale grouping (100 per cent success rate), and very similar for the other regions (all success rates in the high 90s).

than others. Supply costs change less than 25 per cent with a capital cost change of 25 per cent since there are other expenses including operating and processing costs, royalties, and taxes. For the most part, the supply cost changes were symmetrical for each grouping whether capital costs increased or decreased. Slight asymmetry arises depending on the capital deductions from royalties and taxes.

Figure 3: 2009 Rate of Return under various Gas Prices (un-risked)

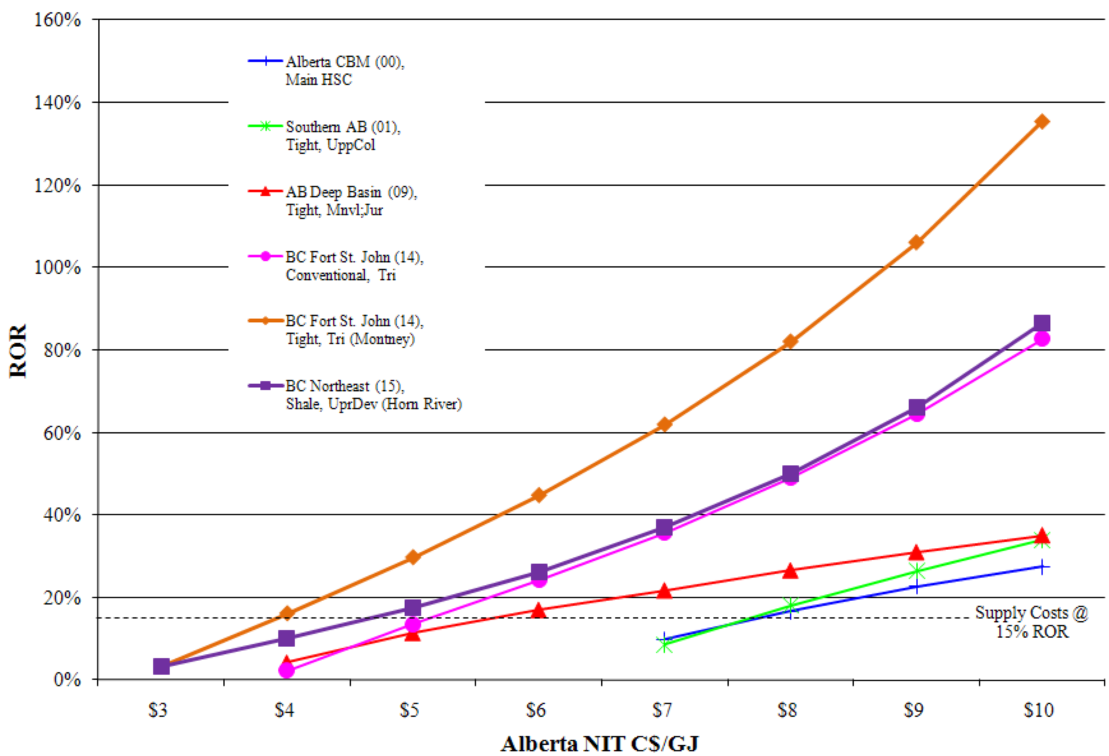
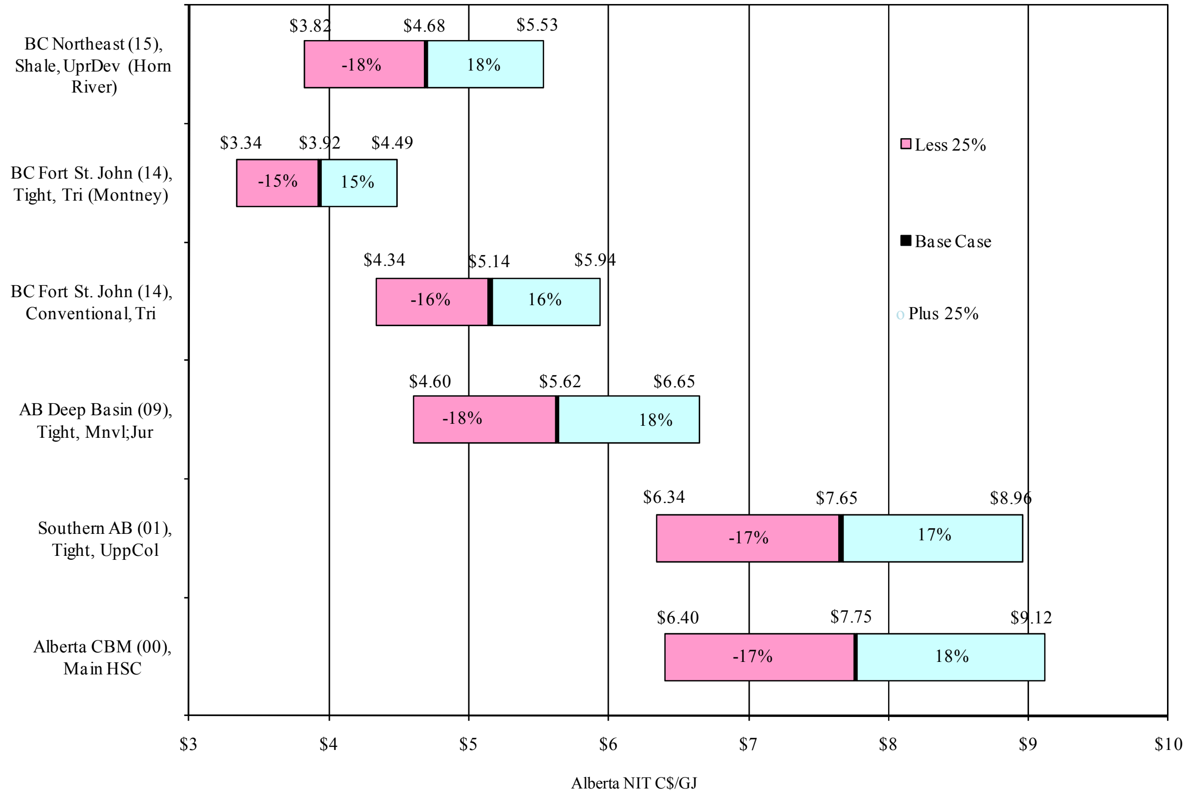


Figure 4: 2009 Supply Cost Capital Cost Sensitivities (un-risked)



Supply Cost Components

Figures 5 and 6 illustrate the components that make up the supply cost for each of the top six groupings, as well as the average for each province and for Western Canada. Capital and operating costs account for significant portions of all six groupings. Taxes and royalties vary provincially, as do capital cost allowances and other deductions. On average, Alberta groupings had a 19 per cent royalty rate and B.C. groupings had a 15 per cent royalty rate. The ROR portion depends on how long it takes before payout (see Table 1), that is, the longer it takes to pay back the capital investment, the more the return component is, as can be seen comparing the Montney to Horn River groupings. The CBM grouping had increased supply costs from 2007 to 2009, in part due to capital cost increases. However, the other shallow grouping in Southern Alberta had slightly lower capital costs, as activity in that area has continued to decline since 2007 and land prices have dropped. The deeper gas groupings had lower supply costs in 2009 compared to 2007, due to capital cost decreases and production rate increases. Appendix 13 includes a comparison of inputs and supply costs for 2007 and 2009. Appendix 14 lists the 2009 supply cost components for every grouping.

Figure 5: 2009 Supply Cost Components (un-risked)[19]

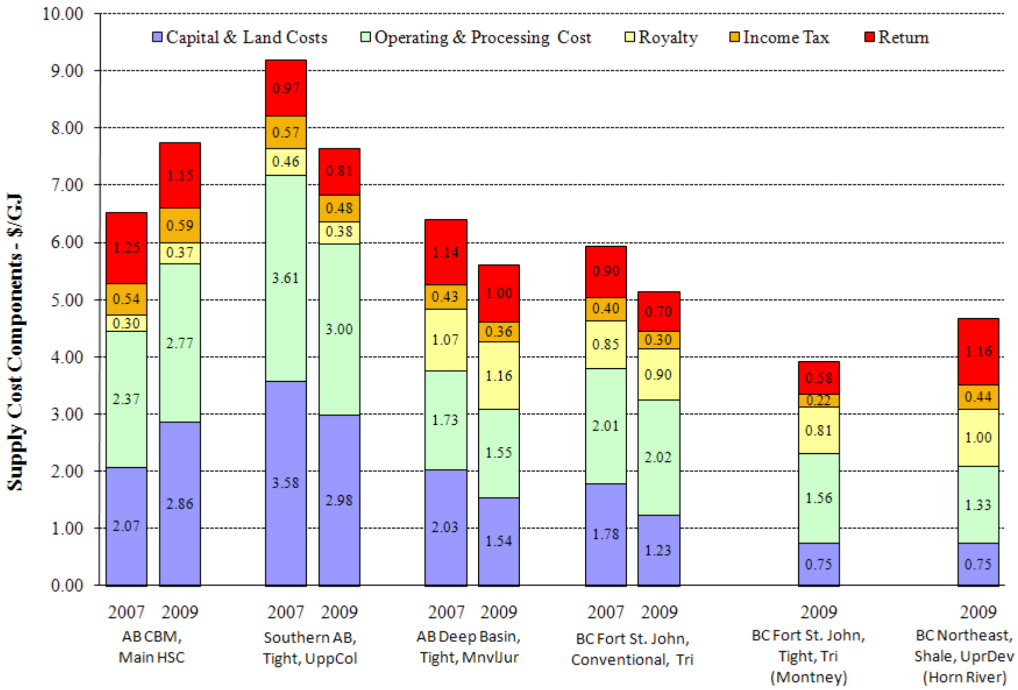
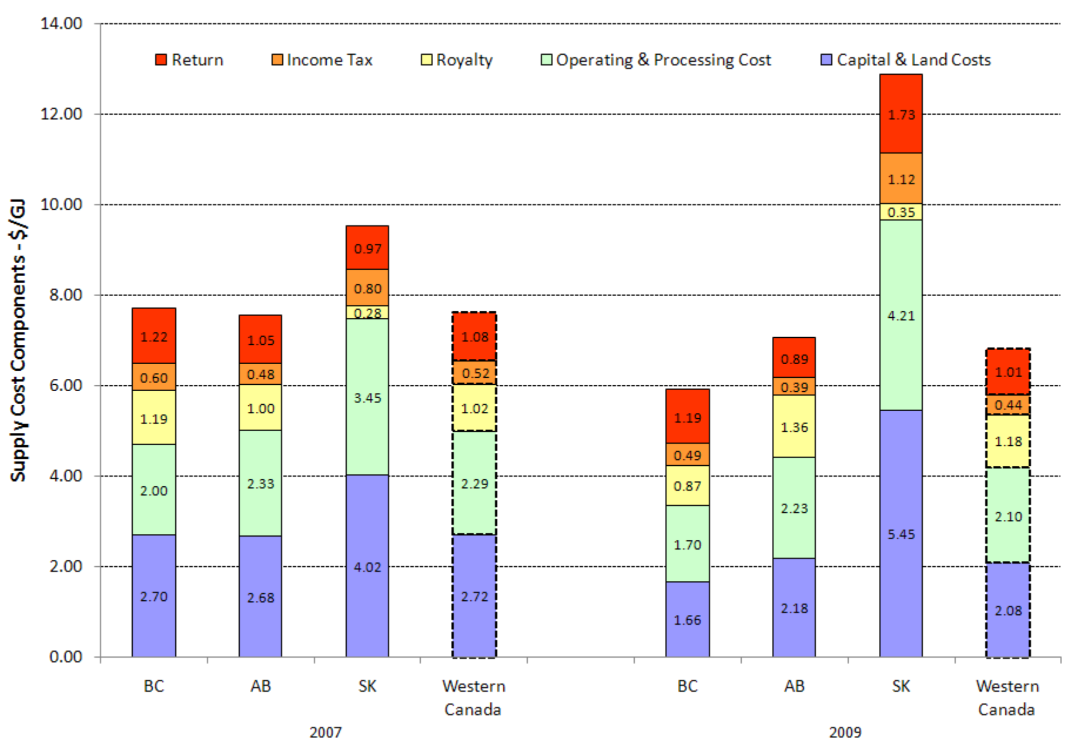


Figure 6: 2009 Averaged Supply Cost Components (un-risked)



19 There are no 2007 results for the Montney and Horn River groupings, as these groupings are relatively new, and data at that time was limited or did not exist.

Observations

Natural gas drilling activity in Western Canada has remained low compared to the boom years of 2005 to 2008. The level of drilling activity is dependent on gas price and cost of production. This study illustrates the average cost structure in Western Canada and identifies the relative economics of various resource developments. There were positive economics for some areas and negative returns for others.

Looking forward, relatively lower gas prices will continue in 2010, however, supply costs of certain areas are expected to continue to decrease. Gas resources with higher NGL content have continued to see increased drilling activity into 2010, as oil prices remain high relative to natural gas prices. Increased knowledge of new resources, drilling efficiency improvements, decreasing costs per hydraulic fracture treatment, the ability to drill multiple wells from one well pad, and multi-lateral horizontal drilling have all led to supply cost decreases. Acquisitions will continue, especially in the deeper tight gas and shale gas developments in Canada and the U.S.A., as the larger producers benefit from economies of scale. Joint ventures have also benefited industry, as foreign investors have teamed up with Canadian and American shale gas producers to earn greater returns and gain knowledge.

Appendices

Appendix 1 – Cost Factors

Strong oil prices ($66.20/barrel at Edmonton averaged in 2009 or $10.82/GJ on an energy equivalency basis) meant producers involved in conventional and unconventional oil found it more 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 increased share of rig activity for oil projects over gas projects in 2009. However, the oil pace could not outweigh the decline in gas activity, and weekly rig counts in 2009 dropped to an average of 233 in 2009, compared to 367 in 2007, lowering the drill-day and service-day costs.

Operating costs were lower in 2009 versus 2007 as the cost of fuel and power dropped by about 22 per cent on average[20] in Western Canada. Processing costs for new production in 2009 were higher as a result of increased production from plays with high NGL content that require additional processing, like the Montney play in the Fort St. John area.

Activity in oil plays and growth in oil sands increased other well costs in 2009 from 2007 levels. Casing, tubing, equipment rentals, and transportation costs increased on average.

Overall, the average capital cost of a well in Western Canada increased, from $2.02 million/well in 2007 to $2.46 million/well in 2009. The average well is deeper and more complex, such as in the large Northeast B.C. plays in 2009. This factor, along with the cost factors noted above, were the main drivers increasing average capital cost.

In addition, ongoing technology and efficiency improvements could lead to future declines in well costs.

[20] Petroleum Services Association of Canada. *2010 Well Cost Study*, November 5, 2009.

Appendix 2 – Production and Cost Input Methodology

A2.1 Formation Groupings

For each region, the producing formations were grouped on a geological basis, and the supply costs were calculated for each of these groupings. The formations were 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 commingled.

A2.2 Resource Types

There were four resource types analyzed in this study – conventional gas, tight gas, coal bed methane (CBM) and shale. The split between conventional gas and tight gas is based on the tight gas plays defined by Forward Energy Group Inc.[21] 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 2009 were not included in this analysis, as there was not enough data on the production profiles or cost estimates. Resource types excluded were tight gas in the Central Foothills Mannville grouping, tight gas in the lower Triassic and Mississippian groupings in Peace River, tight gas in the Mannville and Devonian groupings in Fort St. John, and other CBM areas besides the Horseshoe Canyon (HSC) and Mannville resources.

A2.3 Production Inputs

Historical well data[22] from 1998 to December 2009 was used to calculate the 2009 well inputs. The inputs were used to represent the average well in that grouping drilled in 2009. 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 expected production level). Historical 2009 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 2009 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[23] in each year (1998 to 2009), linear 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

[21] Forward Energy Group Inc. Web site: http://www.forwardenergy.ca

[22] Well data from GeoScout.

[23] Wells that start producing in each year.

2009, only their initial production rates and a few months of production were available, so historical curve analysis is used to extrapolate the performance of the 2009 wells. Initial production and decline parameter inputs are listed in Appendix 6.

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 per cent 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

Cost data from petroCUBE 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 2009 is used to calculate ratios that were applied to the petroCUBE cost data. For each grouping, production data is summed for each formation. Ratios were calculated by formation (see Appendix 9), and these ratios were applied to the cost data to get average costs weighted by historical production. These costs were drilling and completion costs, tie-in costs, reclamation costs, land costs, processing costs and variable and fixed operating costs. Cost data was also gathered from public presentations, industry websites and industry consultations. See Appendices 10 and 11 for the cost input tables.

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 examined by varying gas prices or capital costs. A total of 22 cash flow estimates were prepared for each grouping consisting of: one at today's costs and ten runs under varying gas price assumptions, all under a no risk assumption (probability of a successful well at 100 per cent) and a risked analysis (probability of a dry well, and its accompanying costs, taken into account). Twelve capital cost sensitivity tests were also run for six specific groupings.

A3.1 Cash Flow Analysis

Supply costs and ROR were calculated from the cash flow analysis. All cash flow components are in 2009 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 were 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 ROR is found. Payout occurs when the cumulative sum of discounted cash flows, starting in the first period, equals zero. Upfront capital costs lead 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 found given a 15 per cent ROR and NPV equal to zero
- ROR and payout found given a supply cost (sales price) and NPV equal to zero

In this analysis production, costs and royalties were calculated on a monthly basis. The net monthly revenues, equal to production multiplied by price less costs and royalties, were summed together to get annual totals and then the taxable income and taxes due are calculated. The taxes due were 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

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

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

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

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

$$Capital\ Costs_i = Drilling,\ casing,\ completing,\ tie\text{-}in\ costs + Land\ Costs\ in\ first\ month$$

= Reclamation costs in last month of production
= 0 otherwise

i = month i
y = year y
k = product k (natural gas, 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 were summed to get total revenue. For some groupings, products other than natural gas were included. Butane, propane, 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 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 $3 to $12/GJ, in one-dollar increments. The natural gas price is the market price per gigajoule in 2009 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 2009, and future prices were escalated at an annual real inflation rate of two per cent. For instance, if the price in 2009 is $3.85 (a market price of $4 less $0.15), the price in 2010 will be C2009$3.93/GJ (a two per cent real annual inflation applied to the $3.85), and so on for subsequent years of production.

Prices for the other products were assumed as follows. The plant gate sulphur price for 2009 is set at $37.29 per tonne, in 2009 Canadian dollars. It is then escalated for future years at a real annual inflation rate of two per cent.[24] Price ratios are applied to assign prices for the other products. The propane and butane prices for a given year were set at three times the wellhead natural gas price and the pentanes and heavier molecules (pentanes plus) price was set to four times the wellhead natural gas price. Converting raw gas into these different products required 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 31.000 GJ per cubic metre for pentanes plus.

A3.3 Success and Abandonment

Since there is a chance that a drilled well 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

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[24] The average annual inflation rate in Canada (using total Consumer Price Index (CPI)) was 1.6 per cent from 2007 to 2009.

multiplied with costs each month.[25] 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 were 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 per cent inflation rate. Note that unsuccessful wells 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 human resources. Variable operating costs, such as fuel and power, are a cost per unit of marketable production. The variable costs were in 2009 Canadian dollars and were the costs incurred in 2009. Future operating costs were inflated at the two per cent annual rate.

Raw gas needs to be processed into marketable gas before going to market. Processing costs are dollars per unit of production and are inflated at the two per cent 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 2009 for British Columbia and Saskatchewan were used.[26] The new royalty framework for Alberta, released October 2007[27], was used in the Alberta economic analysis.[28] Gross royalties payable are the product of the royalty rate (in per cent) 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 were 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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25 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).

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

27 Government of Alberta, *About Royalties*: http://www.energy.gov.ab.ca/About_Us/Royalty.asp

28 The Alberta natural gas royalty formulas that are effective January 1, 2011 are not used, as they were not in existence until 2010.

A3.6.1 B.C. Royalties

The Base 9[29] gas royalty formula is used to calculate the B.C. gross royalties[30] for natural gas. This formula retains nine per cent of the price when the price is less than or equal to the select price, and 40 per cent 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 per cent. Wells producing less than 5000 $10^3 m^3$/day on average for a month will see a decrease in the royalty rate.

Other products produced along with the natural gas were also subject to royalty payments. Royalties on natural gas liquids were levied at a flat rate of 20 per cent of the sales volume and royalties on sulphur were levied at a flat rate of 16 2/3 per cent 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 were 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, were 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.[31]

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.[32] These new royalty formulas came into effect on January 1, 2009, and were used in this analysis.

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 per cent, and the sum – the total royalty rate – has a minimum of five per cent and a maximum of 50 per cent. 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. Royalty rates, as of December 2006, for propane, butane and methane were used in this analysis. The royalty rate is then multiplied by gross revenues to find the gross royalty in each month.

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29 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.

30 For more information use the source noted in footnote 26 above.

31 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.

32 Government of Alberta, *About Royalties*: http://www.energy.gov.ab.ca/About_Us/Royalty.asp

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 were multiplied by the natural gas royalty rate and subtracted from the total gross royalty amount to get a net royalty payable amount each month.

There is also a deep gas royalty relief in place. The Alberta government announced new deep resource programs to promote high cost oil and gas development on April 10, 2008. Those programs applied to wells that began drilling on or after April 10, 2008, and since this analysis is looking at the economics of 2009 drilled wells, these programs were included in the calculations.

A3.6.3 Saskatchewan Royalties

The royalty formula for 'Fourth Tier[33] 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 per cent. 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 were no NGL royalties, so higher processing costs were 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 were used in this analysis. The 2007 corporate income tax rate is 22.12 per cent for 2007, and will drop to 15 per cent by 2012. These rates presented below were used in the analysis and it is assumed that production beyond 2012 will face the 15 per cent 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 December 2009, were assumed. The provincial tax rates were assumed constant throughout the productive lifetime of each well. The tax rates were:

	British Columbia	Alberta	Saskatchewan
Provincial Tax Rate	12%	10%	13%

Before tax income (BTI) is revenue (production multiplied by price) less operating costs and royalty payable. BTI was calculated for each month and summed to provide a BTI for each

[33] Gas produced from gas wells drilled on or after October 1, 2002.

calendar year. Taxable income is BTI less allowed depreciation and capital cost allowances in a given year. The tax rates were 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.

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.

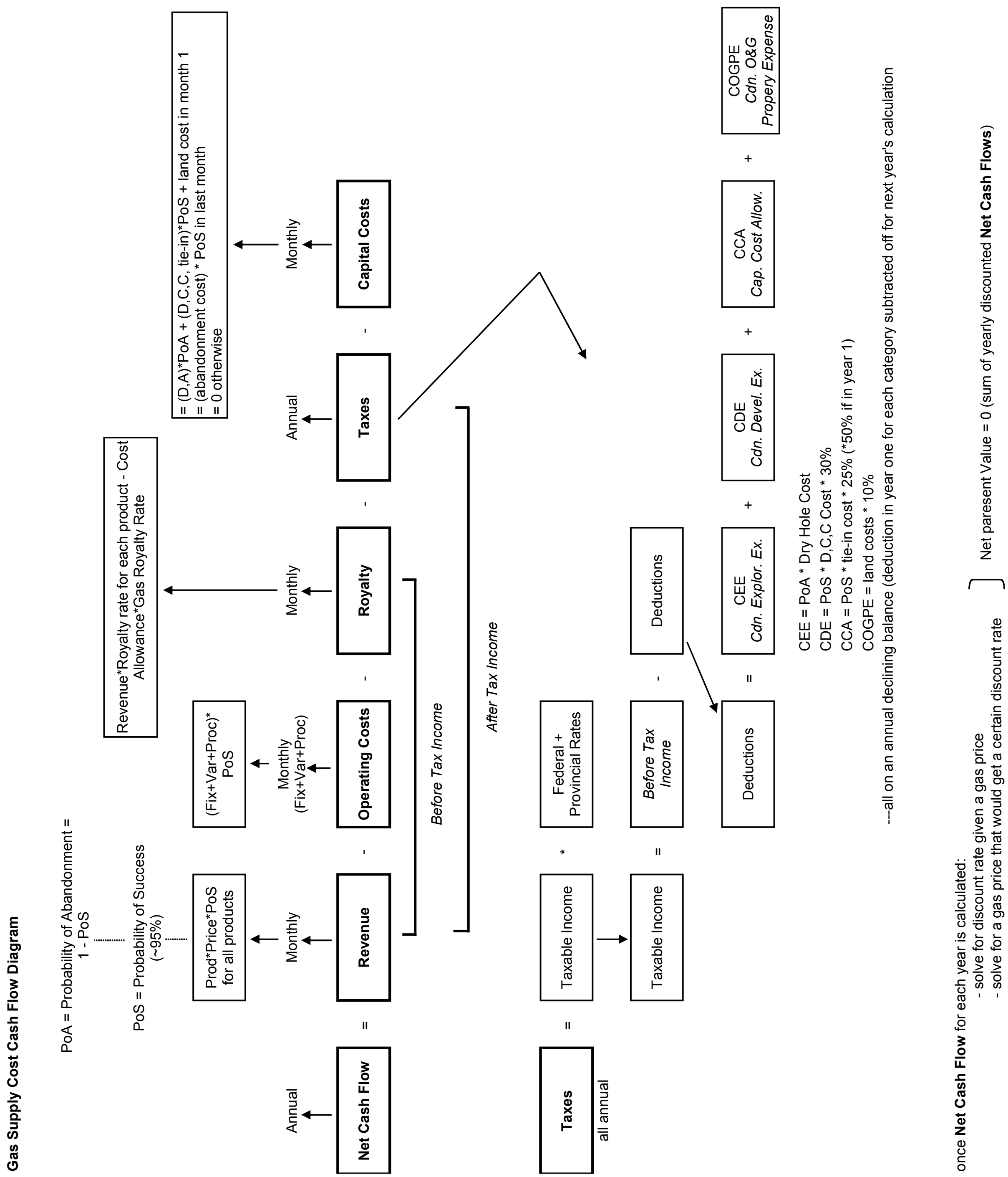
The costs must also be weighed by the probability of success. If the well is abandoned, the producer will incur land, drilling and abandonment costs and a reclamation cost. If the well is successful, the producer will incur land costs, drilling, casing and tie-in costs and reclamation costs. So, the 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 were determined, the NPV and payouts were 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 in Figure A1.

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	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	Jur
Kaybob	08	Conventional	UprColr;Colr
Kaybob	08	Conventional	Mnvl;Jur
Kaybob	08	Conventional	Tri
Kaybob	08	Conventional	UprDvn
Kaybob	08	Tight	Colr;Mnvl
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

Area Name	Area Number	Resource Type	Resource Group
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
Peace River	11	Tight	UprColr
Peace River	11	Tight	MdlMnvl;LwrMnvl
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
BC Deep Basin	13	Tight	LwrTri
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
Fort St. John	14	Tight	Tri
Fort St. John	14	Tight	Perm;Miss
Northeast BC	15	Conventional	LwrMnvl
Northeast BC	15	Conventional	Perm;Miss
Northeast BC	15	Conventional	UprDvn;MdlDvn
Northeast BC	15	Tight	UprDvn
Northeast BC	15	Shale	MdlDvn
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

Rég.	Type de ressource	Groupe de ressources	Groupe de ressources	Production initiale en Mpi3/j	Taux 1re baisse	Taux 2e baisse	Mois avant 2e baisse	Taux 3e baisse	Mois avant 3e baisse	Taux 4e baisse	Mois avant 4e baisse	Taux 5e baisse	Mois avant 5e baisse
00	CBM	HSC principa	HSC principal	0.077442	0.65	0.2	5	0.12	30	0.12	400	0.12	500
00	CBM	Mannville	Mannville	0.270235831	0.01	0.4	15	0.2	30	0.15	50	0.1	100
01	Classique	02;03;04	Tert;UprCret;UprColr	0.095	0.75	0.4	8	0.22	20	0.16	45	0.12	90
01	Classique	05	Colr	0.132199025	0.9	0.5	7	0.35	20	0.25	35	0.12	90
01	Classique	06;07;08	Mnvl	0.277678332	0.65	0.5	7	0.32	20	0.16	45	0.12	90
01	Rés. étanche	04	UprColr	0.074190072	0.8	0.4	7	0.22	20	0.16	45	0.12	90
02	Classique	02;03;04	Tert;UprCret;UprColr	0.101660177	1	0.5	10	0.22	20	0.16	45	0.12	90
02	Classique	05	Colr	0.511342651	2	0.8	7	0.7	16	0.3	20	0.12	50
02	Classique	07;08	MdlMnvl;LwrMnvl	0.540356778	0.95	0.45	7	0.4	22	0.2	45	0.1	90
02	Classique	09;13	Jur;Miss	0.21671289	1	0.8	7	0.22	20	0.16	40	0.1	90
02	Rés. étanche	04	UprColr	0.123598953	0.95	0.5	7	0.2	16	0.16	45	0.1	90
02	Rés. étanche	05	Colr	0.25	1.2	0.45	7	0.25	20	0.15	40	0.1	90
02	Rés. étanche	08	LwrMnvl	0.237004101	0.8	0.4	7	0.3	20	0.2	45	0.15	90
03	Classique	13;14	Miss;UprDvn	5.8	0.3	0.6	7	0.3	20	0.2	40	0.12	90
04	Classique	03;04	UprCret;UprColr	0.111202915	1.5	0.5	7	0.25	20	0.12	50	0.12	500
04	Classique	05;06;07;08	Colr;Mnvl	0.181972818	1.1	0.55	7	0.35	20	0.2	45	0.12	90
04	Rés. étanche	04	UprColr	0.056284375	1.5	0.5	7	0.2	15	0.1	45	0.1	500
05	Classique	02;03	Tert;UprCret	0.113936315	0.7	0.5	7	0.3	15	0.2	30	0.12	80
05	Classique	05	Colr	0.16	1	0.7	7	0.3	15	0.12	40	0.1	60
05	Classique	06;07;08	Mnvl	0.27	0.9	0.65	7	0.5	20	0.3	30	0.12	60
05	Classique	13;14	Miss;UprDvn	0.182	0.7	0.55	7	0.3	20	0.2	40	0.1	60
05	Rés. étanche	05	Colr	0.12	0.85	0.5	7	0.35	20	0.12	45	0.1	90
05	Rés. étanche	06;07;08	Mnvl	0.634959099	0.95	0.4	7	0.3	20	0.15	35	0.1	60
06	Classique	02	Tert	0.230133118	0.65	0.45	8	0.35	20	0.25	45	0.1	70
06	Classique	03;04	UprCret;UprColr	0.345	0.7	0.45	7	0.3	20	0.2	35	0.1	60
06	Classique	06;07;08	Mnvl	0.6	0.65	0.45	7	0.35	20	0.2	45	0.12	90
06	Classique	08;09	LwrMnvl;Jur	0.667681292	0.9	0.45	7	0.22	20	0.16	45	0.12	90
06	Classique	13	Miss	0.85	0.9	0.55	7	0.35	20	0.15	45	0.12	90
06	Classique	14	UprDvn	0.672353316	0.7	1.5	7	0.8	15	0.4	25	0.12	80
06	Rés. étanche	05	Colr	0.547377178	0.85	0.45	7	0.25	20	0.15	40	0.1	60
06	Rés. étanche	06;07;08	Mnvl	0.535675918	0.75	0.6	7	0.25	20	0.16	40	0.1	60
07	Classique	04	UprColr	2.553558698	1.3	0.45	7	0.3	15	0.2	25	0.12	45
07	Classique	05;06;07;08	Colr;Mnvl	1.7	0.8	0.5	7	0.25	25	0.16	45	0.12	90
07	Classique	09;10;11;12	Jur;Tri;Perm	3	0.75	0.5	7	0.22	20	0.16	45	0.12	90
07	Classique	13	Miss	4.5	0.55	0.7	7	0.5	20	0.3	45	0.12	90
07	Classique	14;15	UprDvn;MdlDvn	2	0.6	0.5	7	0.3	20	0.35	45	0.15	90
07	Rés. étanche	04;05	UprColr;Colr	1.7	0.8	0.4	7	0.22	20	0.16	45	0.12	90
07	Rés. étanche	09	Jur	3	0.9	0.5	7	0.4	20	0.16	45	0.12	90
08	Classique	04;05	UprColr;Colr	0.72	1	0.5	7	0.22	20	0.16	45	0.12	90
08	Classique	06;07;08;09	Mnvl;Jur	0.957260664	0.95	0.55	7	0.35	25	0.2	45	0.12	90
08	Classique	10;11	Tri	1.578634121	1.4	0.8	7	0.25	20	0.15	45	0.12	90
08	Classique	14	UprDvn	0.9	0.9	0.65	7	0.25	20	0.16	45	0.12	90
08	Rés. étanche	05;06;07;08	Colr;Mnvl	0.772523822	0.95	0.6	8	0.35	20	0.2	45	0.12	90
09	Classique	03	UprCret	0.459187828	0.9	0.4	7	0.25	20	0.16	45	0.12	90

Rég.	Type de ressource	Groupe de ressources	Groupe de ressources	Production initiale en Mpi3/j	Taux 1re baisse	Taux 2e baisse	Mois avant 2e baisse	Taux 3e baisse	Mois avant 3e baisse	Taux 4e baisse	Mois avant 4e baisse	Taux 5e baisse	Mois avant 5e baisse
09	Classique	04	UprColr	0.9	1.2	0.6	7	0.35	20	0.2	45	0.12	90
09	Classique	06;07;08;09	Mnvl;Jur	0.5	0.85	0.4	7	0.25	25	0.16	45	0.12	90
09	Classique	10;11	Tri	1.29303826	1.25	0.7	7	0.35	20	0.25	40	0.12	90
09	Classique	14	UprDvn	4.187941319	0.65	0.4	7	0.22	20	0.16	45	0.12	90
09	Rés. étanche	04	UprColr	0.688389692	1.1	0.6	7	0.3	20	0.22	25	0.12	45
09	Rés. étanche	05	Colr	0.770971022	0.65	0.45	7	0.24	20	0.16	45	0.12	90
09	Rés. étanche	06;07;08;09	Mnvl;Jur	1.115456951	0.9	0.45	7	0.22	20	0.16	45	0.1	90
10	Classique	06;07;08;14	Mnvl;UprDvn	0.179228825	0.7	0.45	7	0.22	20	0.16	45	0.12	90
11	Classique	04	UprColr	0.229807871	0.85	0.55	7	0.3	20	0.16	45	0.12	90
11	Classique	05;06	Colr;UprMnvl	0.476062312	0.65	0.85	7	0.45	20	0.25	45	0.12	90
11	Classique	07;08	MdlMnvl;LwrMnvl	0.59375839	1.2	0.55	7	0.3	20	0.2	45	0.12	90
11	Classique	10	UprTri	1.074786844	1.25	0.65	7	0.3	20	0.2	38	0.12	90
11	Classique	11	LwrTri	1.327727327	1.05	0.7	5	0.3	20	0.15	45	0.1	500
11	Classique	13	Miss	1.248955148	1.2	0.95	7	0.3	15	0.16	45	0.12	90
11	Classique	14;15	UprDvn;MdlDvn	0.4	0.75	1.2	7	0.25	20	0.2	35	0.12	90
11	Rés. étanche	04	UprColr	0.275	0.85	0.4	7	0.27	20	0.16	45	0.12	90
11	Rés. étanche	07;08	MdlMnvl;LwrMnvl	0.495	1.4	0.55	7	0.3	20	0.2	45	0.12	90
12	Classique	06;07;08	Mnvl	0.402640897	0.7	0.4	8	0.3	20	0.16	45	0.12	500
12	Classique	13	Miss	0.155	0.85	0.5	7	0.25	20	0.16	45	0.1	90
12	Classique	14	UprDvn	1.126290732	1.5	0.55	7	0.4	20	0.25	40	0.12	90
12	Classique	15	MdlDvn	1.15	1.5	1.3	7	0.3	20	0.16	45	0.12	90
13	Classique	05	Colr	0.65	1.45	0.65	7	0.22	20	0.16	45	0.12	90
13	Classique	11	LwrTri	1.7	0.65	0.4	7	0.3	20	0.2	45	0.12	90
13	Rés. étanche	05	Colr	2.2	1.6	0.55	7	0.25	20	0.16	45	0.1	500
13	Rés. étanche	06;07;08	Mnvl	2.6	1.85	0.5	7	0.24	20	0.16	45	0.12	90
13	Rés. étanche	11	LwrTri	3.5	1.9871418	0.8037338	5	0.2284124	13	0.2284124	500	0.2284124	500
14	Classique	06;07;08	Mnvl	0.35	0.85	0.45	7	0.22	20	0.16	45	0.12	90
14	Classique	10;11	Tri	1.212	0.85	0.4	7	0.22	20	0.16	45	0.12	90
14	Classique	12;13	Perm;Miss	1.805	0.75	0.5	7	0.25	20	0.15	45	0.12	90
14	Classique	14;15	UprDvn;MdlDvn	2.3	0.5	0.35	8	0.25	20	0.16	45	0.12	90
14	Rés. étanche	10;11	Tri	3.5	0.635242	0.1405806	10	0.1405806	500	0.1405806	500	0.1405806	500
14	Rés. étanche	12;13	Perm;Miss	2.25	0.75	0.4	7	0.2	20	0.16	45	0.12	90
15	Classique	08	LwrMnvl	0.17	0.55	0.35	7	0.22	20	0.12	45	0.05	90
15	Classique	12;13	Perm;Miss	0.774	1.35	0.6	7	0.22	20	0.16	45	0.12	90
15	Classique	14;15	UprDvn;MdlDvn	1.25	0.75	0.65	7	0.3	20	0.16	45	0.12	90
15	Rés. étanche	14	UprDvn	1.1	1.65	0.65	7	0.27	20	0.16	45	0.12	90
15	Schistes	14	Schistes	6	1.1574098	0.2747832	13	0.2243865	25	0.0618754	37	0.0618754	500
16	Classique	05;06;07;08	Colr;Mnvl	1.23	0.55	0.5	15	0.5	500	0.5	500	0.5	500
16	Classique	10;11;12;13	Tri;Perm;Miss	1.693	0.45	0.35	7	0.25	25	0.25	500	0.25	500
17	Rés. étanche	04	UprColr	0.073	0.8	0.43	8	0.31	18	0.22	35	0.15	60
18	Classique	05	Colr	0.09	0.75	0.35	15	0.25	30	0.17	60	0.17	500
18	Classique	07;08;13	MdlMnvl;LwrMnvl;Miss	0.23	0.8	0.4	14	0.3	40	0.25	70	0.25	500

Appendix 7 – Gas Compositions

Area	RsrcType	Resource Group	Resource Group	C3 barrels per marketable mmcf	C4 barrels marketable mmcf	C5+ barrels marketable mmcf	Sulphur tonnes per marketable mmcf
00	CBM	Main HSC	Main HSC	0	0	0	0
00	CBM	Mannville	Mannville	0	0	0	0
01	Conventional	02;03;04	Tert;UprCret;UprColr	0	0.08	0.41	0
01	Conventional	05	Colr	0.05	0.48	1.92	0.0007
01	Conventional	06;07;08	Mnvl	0.38	1.67	5.21	0.0025
01	Tight	04	UprColr	0	0.1	0.39	0
02	Conventional	02;03;04	Tert;UprCret;UprColr	0.02	0.12	0.44	0.001
02	Conventional	05	Colr	0	0.2	0.94	0.0009
02	Conventional	07;08	MdlMnvl;LwrMnvl	0.46	1.91	7.01	0.0109
02	Conventional	09;13	Jur;Miss	0.75	2.69	13.11	0.1813
02	Tight	04	UprColr	0	0.04	0.23	0
02	Tight	05	Colr	0.1	0.63	1.8	0
02	Tight	08	LwrMnvl	0.6	2.07	8.22	0.0829
03	Conventional	13;14	Miss;UprDvn	5.94	6.04	21.6	4.2071
04	Conventional	03;04	UprCret;UprColr	0	0.06	0.28	0.0008
04	Conventional	05;06;07;08	Colr;Mnvl	0.02	0.28	0.96	0.0017
04	Tight	04	UprColr	0	0.03	0.13	0
05	Conventional	02;03	Tert;UprCret	0.01	0.16	0.72	0.0016
05	Conventional	05	Colr	0.31	0.95	3.17	0
05	Conventional	06;07;08	Mnvl	0.65	1.86	5.12	0.0101
05	Conventional	13;14	Miss;UprDvn	1.21	3.64	12.31	0.2296
05	Tight	05	Colr	0.57	2.15	7.96	0.0114
05	Tight	06;07;08	Mnvl	0.94	3.39	10.77	0.0095
06	Conventional	02	Tert	0.06	0.38	1.67	0.0043
06	Conventional	03;04	UprCret;UprColr	6.92	6.23	20.48	0.0153
06	Conventional	06;07;08	Mnvl	6.36	5.77	15.04	0.0034
06	Conventional	08;09	LwrMnvl;Jur	6.21	5.63	16.55	0.0218
06	Conventional	13	Miss	3.39	4.06	16.75	0.2376
06	Conventional	14	UprDvn	18.8	23.36	94.98	4.6315
06	Tight	05	Colr	4.46	4.76	14.58	0.0226
06	Tight	06;07;08	Mnvl	7.87	6.61	16.64	0.0939
07	Conventional	04	UprColr	7.08	4.86	14.08	0.0963
07	Conventional	05;06;07;08	Colr;Mnvl	0.9	1.34	4.73	0.0909
07	Conventional	09;10;11;12	Jur;Tri;Perm	0.07	0.21	1.12	0.9984
07	Conventional	13	Miss	1.23	1.2	3.68	1.6192
07	Conventional	14;15	UprDvn;MdlDvn	0.06	0.28	2.35	4.2066
07	Tight	04;05	UprColr;Colr	0.73	2.66	18.78	0.3842
07	Tight	09	Jur	0	0.19	1.35	0
08	Conventional	04;05	UprColr;Colr	5.16	3.89	7.84	0.0023
08	Conventional	06;07;08;09	Mnvl;Jur	2.3	2.91	8.88	0.0199
08	Conventional	10;11	Tri	10.37	7.48	18.88	0.7438
08	Conventional	14	UprDvn	17.48	18.04	81.7	3.1326
08	Tight	05;06;07;08	Colr;Mnvl	11.11	6.69	11.5	0.0259
09	Conventional	03	UprCret	3.56	3.68	8.18	0
09	Conventional	04	UprColr	11.71	6.89	12.63	0.0041
09	Conventional	06;07;08;09	Mnvl;Jur	8.36	5.05	9.82	0.0559
09	Conventional	10;11	Tri	3.53	2.06	5.49	1.2427
09	Conventional	14	UprDvn	0.53	1.18	10.56	4.7413
09	Tight	04	UprColr	5.67	5.1	15	0.013
09	Tight	05	Colr	6.98	3.96	9.45	0.1195
09	Tight	06;07;08;09	Mnvl;Jur	8.63	4.64	8.79	0.0167
10	Conventional	06;07;08;14	Mnvl;UprDvn	0	0.01	0.04	0
11	Conventional	04	UprColr	0.31	0.69	2.52	0.0013
11	Conventional	05;06	Colr;UprMnvl	0.43	0.29	1.87	0.002
11	Conventional	07;08	MdlMnvl;LwrMnvl	0.16	0.45	2.96	0.0045
11	Conventional	10	UprTri	0.86	1.5	4.95	0.21
11	Conventional	11	LwrTri	0.74	2.19	9.33	0.4875
11	Conventional	13	Miss	5.67	4.43	11.9	0.0056
11	Conventional	14;15	UprDvn;MdlDvn	0.42	2.15	5.96	0.097
11	Tight	04	UprColr	0.31	0.69	2.52	0.0013
11	Tight	07;08	MdlMnvl;LwrMnvl	0	0.26	1.07	0
12	Conventional	06;07;08	Mnvl	0.09	0.44	1.39	0.0008
12	Conventional	13	Miss	0	0.16	0.56	0
12	Conventional	14	UprDvn	0.53	2.55	14.59	0.0644

12	Conventional	15	MdlDvn	4.77	3.48	7.51	0.5341
13	Conventional	05	Colr	2.65	2.31	3.44	0
13	Conventional	11	LwrTri	0.42	0.35	0.41	0.2479
13	Tight	05	Colr	0	0.26	1.07	0
13	Tight	06;07;08	Mnvl	0.09	0.18	0.61	0
13	Tight	11	LwrTri	0.13	0	0	28
14	Conventional	06;07;08	Mnvl	15.96	8.14	7.19	0.0242
14	Conventional	10;11	Tri	10.71	6.91	7.63	0.5024
14	Conventional	12;13	Perm;Miss	3.26	2.97	6.45	0.0818
14	Conventional	14;15	UprDvn;MdlDvn	0.03	0.06	4	0.0402
14	Tight	11	Tri	8.05	4.12	6.88	0
14	Tight	12;13	Perm;Miss	3.26	2.97	6.45	0.0818
15	Conventional	08	LwrMnvl	8.27	6.74	8.05	0
15	Conventional	12;13	Perm;Miss	0.03	0.08	0.31	0.0467
15	Conventional	14;15	UprDvn;MdlDvn	0.13	0.15	0.18	0.5967
15	Tight	14	UprDvn	0	0.15	1.47	0.0027
15	Shale	14	Shale	0	0	0	0
16	Conventional	05;06;07;08	Colr;Mnvl	0.64	0.59	0.67	0.005
16	Conventional	10;11;12;13	Tri;Perm;Miss	0.01	0.06	0.24	2.9532
17	Tight	04	UprColr	0	0.1	0.39	0
18	Conventional	05	Colr	0.02	0.28	0.96	0.0017
18	Conventional	07;08;13	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	2081	95.0%	100.0%
01	Conventional	Tert;UprCret;UprColr	809	95.5%	99.9%
01	Conventional	Colr	902	95.0%	93.5%
01	Conventional	Mnvl	1167	92.2%	90.0%
01	Tight	UprColr	693	94.4%	99.6%
02	Conventional	Tert;UprCret;UprColr	962	94.0%	95.5%
02	Conventional	Colr	1308	94.5%	62.5%
02	Conventional	MdlMnvl;LwrMnvl	1765	88.3%	97.0%
02	Conventional	Jur;Miss	2236	86.6%	100.0%
02	Tight	UprColr	390	95.4%	99.9%
02	Tight	Colr	2403	94.8%	65.0%
02	Tight	LwrMnvl	2460	90.9%	99.9%
03	Conventional	Miss;UprDvn	3900	63.5%	80.0%
04	Conventional	UprCret;UprColr	479	95.4%	96.0%
04	Conventional	Colr;Mnvl	836	94.7%	95.0%
04	Tight	UprColr	896	95.8%	90.0%
05	Conventional	Tert;UprCret	922	93.5%	99.0%
05	Conventional	Colr	1343	94.4%	98.0%
05	Conventional	Mnvl	1158	91.9%	78.0%
05	Conventional	Miss;UprDvn	1673	89.1%	93.0%
05	Tight	Colr	1524	92.1%	99.9%
05	Tight	Mnvl	1867	90.2%	92.3%
06	Conventional	Tert	1199	90.9%	97.0%
06	Conventional	UprCret;UprColr	1666	87.2%	91.0%
06	Conventional	Mnvl	2810	86.7%	100.0%
06	Conventional	LwrMnvl;Jur	2775	84.8%	93.0%
06	Conventional	Miss	2732	84.5%	95.0%
06	Conventional	UprDvn	3529	51.5%	75.0%
06	Tight	Colr	1742	88.7%	91.7%
06	Tight	Mnvl	2856	84.4%	95.3%
07	Conventional	UprColr	3546	88.5%	75.0%
07	Conventional	Colr;Mnvl	3588	91.1%	97.0%
07	Conventional	Jur;Tri;Perm	3399	87.4%	99.0%
07	Conventional	Miss	3580	81.8%	81.0%
07	Conventional	UprDvn;MdlDvn	3897	69.3%	100.0%
07	Tight	UprColr;Colr	2955	87.9%	100.0%
07	Tight	Jur	4640	95.7%	100.0%
08	Conventional	UprColr;Colr	2463	90.5%	66.7%
08	Conventional	Mnvl;Jur	2709	89.7%	91.7%
08	Conventional	Tri	3363	82.2%	94.7%
08	Conventional	UprDvn	3828	64.4%	93.0%
08	Tight	Colr;Mnvl	3044	84.9%	92.9%
09	Conventional	UprCret	1090	91.2%	92.0%
09	Conventional	UprColr	2886	86.2%	97.8%
09	Conventional	Mnvl;Jur	3068	84.6%	100.0%
09	Conventional	Tri	3623	84.1%	100.0%
09	Conventional	UprDvn	4529	70.1%	75.0%
09	Tight	UprColr	2463	88.7%	97.8%
09	Tight	Colr	3096	85.6%	92.0%
09	Tight	Mnvl;Jur	3182	85.3%	94.1%
10	Conventional	Mnvl;UprDvn	520	95.1%	81.1%
11	Conventional	UprColr	634	94.5%	76.0%
11	Conventional	Colr;UprMnvl	872	94.6%	80.0%
11	Conventional	MdlMnvl;LwrMnvl	1590	92.4%	78.8%
11	Conventional	UprTri	1070	90.5%	96.0%
11	Conventional	LwrTri	2650	88.7%	99.0%
11	Conventional	Miss	1805	88.8%	100.0%
11	Conventional	UprDvn;MdlDvn	2395	89.0%	62.5%
11	Tight	UprColr	695	94.5%	95.0%
11	Tight	MdlMnvl;LwrMnvl	1390	92.4%	95.0%
12	Conventional	Mnvl	982	94.1%	100.0%
12	Conventional	Miss	486	90.7%	100.0%
12	Conventional	UprDvn	1957	90.8%	87.5%
12	Conventional	MdlDvn	1531	84.0%	100.0%
13	Conventional	Colr	3216	95.1%	50.0%

Area	Resource Type	Resource Group	Total Measured Depth m	Shrinkage % after processing	Probability of Success %
13	Conventional	LwrTri	4452	91.7%	98.3%
13	Tight	Colr	3216	96.4%	100.0%
13	Tight	Mnvl	3850	95.2%	99.3%
13	Tight	LwrTri	4055	95.0%	100.0%
14	Conventional	Mnvl	1062	85.2%	98.0%
14	Conventional	Tri	2086	85.2%	99.1%
14	Conventional	Perm;Miss	3143	91.9%	100.0%
14	Conventional	UprDvn;MdlDvn	4055	89.3%	100.0%
14	Tight	Tri	4055	95.0%	100.0%
14	Tight	Perm;Miss	4055	95.2%	100.0%
15	Conventional	LwrMnvl	1219	92.6%	100.0%
15	Conventional	Perm;Miss	762	89.4%	100.0%
15	Conventional	UprDvn;MdlDvn	1962	79.7%	95.0%
15	Tight	UprDvn	2558	95.3%	98.1%
15	Shale	Shale	4460	85.0%	100.0%
16	Conventional	Colr;Mnvl	2990	90.9%	98.4%
16	Conventional	Tri;Perm;Miss	2741	78.3%	99.0%
17	Tight	UprColr	583	86.0%	100.0%
18	Conventional	Colr	740	80.0%	100.0%
18	Conventional	MdlMnvl;LwrMnvl;Miss	852	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 public information and industry consultation														
00	CBM	Mannville															
01	Conventional	Tert;UprCret;UprColr	1%	55%	44%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
01	Conventional	Colr	0%	2%	10%	87%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
01	Conventional	Mnvl	0%	1%	4%	5%	10%	45%	34%	0%	0%	0%	0%	1%	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	7%	78%	14%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
02	Conventional	Colr	0%	4%	8%	88%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
02	Conventional	MdlMnvl;LwrMnvl	0%	1%	0%	3%	0%	57%	38%	0%	0%	0%	0%	0%	0%	0%	0%
02	Conventional	Jur;Miss	0%	1%	0%	0%	0%	3%	12%	58%	0%	0%	0%	26%	0%	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%	3%	96%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%
02	Tight	LwrMnvl	0%	0%	0%	0%	0%	8%	92%	0%	0%	0%	0%	0%	0%	0%	0%
03	Conventional	Miss;UprDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	87%	11%	0%	0%
04	Conventional	UprCret;UprColr	0%	34%	66%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
04	Conventional	Colr;Mnvl	0%	1%	2%	30%	51%	9%	6%	0%	0%	0%	0%	0%	1%	0%	0%
04	Tight	UprColr	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
05	Conventional	Tert;UprCret	17%	82%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
05	Conventional	Colr	0%	4%	4%	92%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
05	Conventional	Mnvl	0%	1%	0%	2%	25%	28%	43%	0%	0%	0%	0%	0%	0%	0%	0%
05	Conventional	Miss;UprDvn	0%	1%	0%	1%	2%	4%	11%	0%	0%	0%	0%	44%	36%	0%	0%
05	Tight	Colr	0%	0%	5%	95%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
05	Tight	Mnvl	0%	0%	1%	6%	6%	27%	60%	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%	37%	61%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
06	Conventional	Mnvl	1%	0%	0%	0%	0%	98%	0%	0%	0%	0%	0%	0%	0%	0%	0%
06	Conventional	LwrMnvl;Jur	1%	1%	1%	1%	0%	2%	24%	71%	0%	0%	0%	0%	0%	0%	0%
06	Conventional	Miss	0%	0%	1%	0%	0%	2%	7%	8%	0%	0%	0%	82%	0%	0%	0%
06	Conventional	UprDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	98%	0%	0%
06	Tight	Colr	0%	0%	5%	95%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
06	Tight	Mnvl	0%	0%	1%	1%	4%	39%	55%	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%	10%	56%	14%	5%	14%	0%	0%	0%	0%	0%	0%	0%	0%
07	Conventional	Jur;Tri;Perm	0%	0%	0%	1%	2%	0%	5%	15%	40%	33%	5%	0%	0%	0%	0%
07	Conventional	Miss	0%	0%	0%	0%	0%	0%	1%	5%	0%	0%	0%	93%	0%	0%	0%
07	Conventional	UprDvn;MdlDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	10%	90%	0%	0%
07	Tight	UprColr,Colr	0%	0%	28%	72%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
07	Tight	Jur	0%	0%	9%	6%	3%	0%	32%	50%	0%	0%	0%	0%	0%	0%	0%
08	Conventional	UprColr;Colr	0%	1%	77%	23%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
08	Conventional	Mnvl;Jur	0%	0%	1%	1%	10%	9%	36%	41%	0%	0%	0%	2%	0%	0%	0%
08	Conventional	Tri	0%	0%	0%	0%	1%	0%	3%	5%	14%	77%	0%	0%	0%	0%	0%
08	Conventional	UprDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	99%	1%	0%
08	Tight	Colr;Mnvl	0%	0%	1%	11%	21%	20%	46%	1%	0%	0%	0%	0%	0%	0%	0%
09	Conventional	UprCret	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
09	Conventional	UprColr	0%	6%	93%	1%	0%	0%	0%	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	Mnvl;Jur	0%	1%	5%	2%	12%	6%	32%	41%	0%	0%	0%	0%	0%	0%	0%
09	Conventional	Tri	0%	0%	0%	0%	1%	0%	7%	4%	9%	78%	0%	1%	0%	0%	0%
09	Conventional	UprDvn	0%	0%	0%	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%	7%	6%	23%	14%	44%	6%	0%	0%	0%	0%	0%	0%	0%
10	Conventional	Mnvl;UprDvn	0%	0%	0%	0%	52%	13%	24%	0%	0%	0%	0%	0%	10%	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%	1%	34%	66%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	Conventional	MdlMnvl;LwrMnvl	0%	0%	1%	0%	1%	40%	57%	1%	0%	0%	0%	0%	0%	0%	0%
11	Conventional	UprTri	0%	0%	0%	0%	0%	0%	2%	2%	96%	0%	0%	0%	0%	0%	0%
11	Conventional	LwrTri	0%	0%	0%	0%	0%	0%	1%	0%	1%	97%	0%	0%	0%	0%	0%
11	Conventional	Miss	0%	0%	0%	0%	0%	0%	1%	0%	1%	1%	0%	97%	0%	0%	0%
11	Conventional	UprDvn;MdlDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	8%	70%	21%	0%
11	Tight	UprColr	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	Tight	MdlMnvl;LwrMnvl	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%
12	Conventional	Mnvl	0%	0%	0%	0%	10%	78%	9%	0%	0%	2%	0%	0%	0%	0%	0%
12	Conventional	Miss	0%	0%	1%	0%	0%	6%	2%	0%	0%	0%	0%	91%	0%	0%	0%
12	Conventional	UprDvn	0%	0%	1%	0%	0%	2%	0%	0%	0%	0%	0%	1%	95%	0%	0%
12	Conventional	MdlDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	14%	86%	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%	16%	3%	81%	0%	0%	0%	0%	0%	0%	0%	0%
13	Tight	LwrTri	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%
14	Conventional	Mnvl	0%	0%	0%	0%	19%	20%	61%	0%	0%	0%	0%	0%	0%	0%	0%
14	Conventional	Tri	0%	0%	0%	0%	0%	0%	0%	0%	30%	70%	0%	0%	0%	0%	0%
14	Conventional	Perm;Miss	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	46%	54%	0%	0%	0%
14	Conventional	UprDvn;MdlDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	21%	79%	0%
14	Tight	Tri	0%	0%	0%	0%	0%	0%	0%	0%	2%	98%	0%	0%	0%	0%	0%
14	Tight	Perm;Miss	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	37%	63%	0%	0%	0%
15	Conventional	LwrMnvl	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%
15	Conventional	Perm;Miss	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%
15	Conventional	UprDvn;MdlDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	97%	0%
15	Tight	UprDvn	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
15	Shale	Shale	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%
16	Conventional	Colr;Mnvl	0%	0%	0%	6%	10%	14%	70%	0%	0%	0%	0%	0%	0%	0%	0%
16	Conventional	Tri;Perm;Miss	0%	0%	0%	0%	0%	0%	0%	0%	73%	4%	16%	7%	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%	0%	98%	0%	0%	0%	0%	1%	0%	0%	0%

Appendix 10 – 2009 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	126	310	60	70	40
00	CBM	Mannville	504	1239	60	70	40
01	Conventional	02;03;04	106	185	50	35	4
01	Conventional	05	212	400	124	48	4
01	Conventional	06;07;08	305	511	131	63	4
01	Tight	04	126	208	50	35	4
02	Conventional	02;03;04	130	236	50	70	14
02	Conventional	05	278	480	50	70	14
02	Conventional	07;08	450	678	50	70	14
02	Conventional	09;13	485	735	50	70	14
02	Tight	04	160	270	50	70	14
02	Tight	05	292	504	50	70	14
02	Tight	08	438	668	50	70	14
03	Conventional	13;14	12135	15815	2000	74	128
04	Conventional	03;04	178	343	114	41	13
04	Conventional	05;06;07;08	222	418	113	51	12
04	Tight	04	185	352	113	40	12
05	Conventional	02;03	133	323	106	45	14
05	Conventional	05	212	435	106	68	14
05	Conventional	06;07;08	286	558	106	70	14
05	Conventional	13;14	522	837	106	70	14
05	Tight	05	215	439	106	69	14
05	Tight	06;07;08	286	557	106	70	14
06	Conventional	02	136	250	72	45	60
06	Conventional	03;04	170	325	72	74	60
06	Conventional	06;07;08	304	714	195	75	60
06	Conventional	08;09	350	974	214	75	60
06	Conventional	13	448	1300	184	75	60
06	Conventional	14	494	1431	180	75	60
06	Tight	05	263	639	72	75	60
06	Tight	06;07;08	314	729	195	75	60
07	Conventional	04	1620	3330	1500	85	570
07	Conventional	05;06;07;08	2238	4015	1500	85	570
07	Conventional	09;10;11;12	4015	6069	1500	85	570
07	Conventional	13	5364	7743	1500	85	570
07	Conventional	14;15	6077	8712	1500	85	570
07	Tight	04;05	2016	3769	1500	85	570
07	Tight	09	3262	5154	1500	85	570
08	Conventional	04;05	484	897	180	75	171
08	Conventional	06;07;08;09	660	1092	179	75	170
08	Conventional	10;11	861	1316	180	75	171
08	Conventional	14	1052	1529	180	75	171
08	Tight	05;06;07;08	594	1020	180	75	171
09	Conventional	03	1054	1755	270	80	81
09	Conventional	04	1281	1994	270	80	81
09	Conventional	06;07;08;09	1752	2552	270	80	81
09	Conventional	10;11	2184	3751	270	80	81
09	Conventional	14	4531	6325	269	80	81
09	Tight	04	1426	2328	270	80	81
09	Tight	05	1356	2244	270	80	81
09	Tight	06;07;08;09	1688	2611	270	80	81
10	Conventional	06;07;08;14	199	380	150	53	14
11	Conventional	04	515	954	270	55	99
11	Conventional	05;06	657	1102	270	71	99
11	Conventional	07;08	1005	1465	270	75	99
11	Conventional	10	1174	1683	270	75	99
11	Conventional	11	1459	2006	270	75	99

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$
11	Conventional	13	1013	1545	270	75	99
11	Conventional	14;15	1700	2332	270	75	99
11	Tight	UprColr	525	972	270	55	99
11	Tight	MdlMnvl;LwrMnvl	1050	1526	270	75	99
12	Conventional	06;07;08	222	631	414	56	112
12	Conventional	13	262	676	414	55	112
12	Conventional	14	492	931	414	89	112
12	Conventional	15	901	1424	414	94	112
13	Conventional	05	1195	2125	300	80	2345
13	Conventional	11	1665	2650	300	80	2345
13	Tight	05	1195	2125	300	80	2345
13	Tight	06;07;08	1558	2531	300	80	2345
13	Tight	11	1665	5550	300	80	2345
14	Conventional	06;07;08	762	1355	285	100	261
14	Conventional	10;11	1010	1733	430	100	261
14	Conventional	12;13	1348	2010	430	100	261
14	Conventional	14;15	2314	3139	430	100	261
14	Tight	Tri	935	5550	430	100	261
14	Tight	Perm;Miss	1317	5950	430	100	261
15	Conventional	08	935	1480	413	75	1970
15	Conventional	12;13	787	1315	413	65	1970
15	Conventional	14;15	3358	4275	415	75	1970
15	Tight	14	2849	3630	415	75	1970
15	Shale	Shale	3223	6424	415	75	1970
16	Conventional	05;06;07;08	2900	4623	300	85	927
16	Conventional	10;11;12;13	3489	5278	354	85	927
17	Tight	04	100	161	40	35	145
18	Conventional	05	185	385	110	45	145
18	Conventional	07;08;13	257	465	109	64	144

Appendix 11 – 2009 Operating and Processing Costs

Area	Resource Type	Resource Group	Variable Operating Cost $/10^3m^3	Variable Operating Cost $/mcf	Fixed Operating Cost $/month	Processing Cost $/10^3m^3	Processing Cost $/mcf
00	CBM	Main HSC	17.75	0.50	1000.00	21.30	0.60
00	CBM	Mannville	17.75	0.50	1000.00	21.30	0.60
01	Conventional	Tert;UprCret;UprColr	8.21	0.23	775.00	28.39	0.80
01	Conventional	Colr	8.53	0.24	927.79	28.39	0.80
01	Conventional	Mnvl	8.53	0.24	976.71	33.19	0.94
01	Tight	UprColr	8.33	0.23	775.00	28.39	0.80
02	Conventional	Tert;UprCret;UprColr	8.82	0.25	1050.00	40.82	1.15
02	Conventional	Colr	8.82	0.25	1050.00	40.82	1.15
02	Conventional	MdlMnvl;LwrMnvl	9.10	0.26	1169.27	44.20	1.25
02	Conventional	Jur;Miss	10.61	0.30	1488.11	46.63	1.31
02	Tight	UprColr	8.82	0.25	1050.00	40.82	1.15
02	Tight	Colr	8.82	0.25	1050.94	40.84	1.15
02	Tight	LwrMnvl	9.11	0.26	1174.70	44.36	1.25
03	Conventional	Miss;UprDvn	24.02	0.68	15608.35	42.29	1.19
04	Conventional	UprCret;UprColr	9.79	0.28	1458.60	35.23	0.99
04	Conventional	Colr;Mnvl	9.40	0.26	1655.21	32.62	0.92
04	Tight	UprColr	9.33	0.26	1500.00	24.85	0.70
05	Conventional	Tert;UprCret	8.87	0.25	1987.13	24.85	0.70
05	Conventional	Colr	8.87	0.25	2260.80	25.56	0.72
05	Conventional	Mnvl	8.87	0.25	2677.18	28.11	0.79
05	Conventional	Miss;UprDvn	8.87	0.25	2700.00	34.02	0.96
05	Tight	Colr	8.87	0.25	1513.68	28.39	0.80
05	Tight	Mnvl	10.65	0.30	1780.83	32.65	0.92
06	Conventional	Tert	8.13	0.23	1450.00	24.85	0.70
06	Conventional	UprCret;UprColr	11.18	0.31	3023.25	25.56	0.72
06	Conventional	Mnvl	16.19	0.46	3076.63	26.98	0.76
06	Conventional	LwrMnvl;Jur	16.19	0.46	3303.56	28.39	0.80
06	Conventional	Miss	17.16	0.48	3882.48	35.49	1.00
06	Conventional	UprDvn	17.26	0.49	4015.78	39.84	1.12
06	Tight	Colr	11.23	0.32	3050.00	25.56	0.72
06	Tight	Mnvl	16.24	0.46	3098.99	26.98	0.76
07	Conventional	UprColr	34.39	0.97	9250.00	28.84	0.81
07	Conventional	Colr;Mnvl	34.28	0.97	9250.00	23.07	0.65
07	Conventional	Jur;Tri;Perm	34.28	0.97	9250.00	28.23	0.80
07	Conventional	Miss	34.28	0.97	9250.00	30.12	0.85
07	Conventional	UprDvn;MdlDvn	34.28	0.97	9250.00	31.97	0.90
07	Tight	UprColr;Colr	34.39	0.97	9250.00	26.53	0.75
07	Tight	Jur	34.11	0.96	9250.00	23.96	0.68
08	Conventional	UprColr;Colr	16.14	0.45	3318.83	19.49	0.55
08	Conventional	Mnvl;Jur	20.83	0.59	3747.86	27.17	0.77
08	Conventional	Tri	21.00	0.59	3890.68	31.15	0.88
08	Conventional	UprDvn	27.11	0.76	3924.53	42.59	1.20
08	Tight	Colr;Mnvl	20.95	0.59	3629.14	25.79	0.73
09	Conventional	UprCret	19.17	0.54	3960.00	10.65	0.30
09	Conventional	UprColr	19.17	0.54	3960.04	10.65	0.30
09	Conventional	Mnvl;Jur	18.73	0.53	3612.30	12.89	0.36
09	Conventional	Tri	18.76	0.53	3949.03	15.52	0.44
09	Conventional	UprDvn	22.42	0.63	6502.57	22.97	0.65
09	Tight	UprColr	19.17	0.54	3960.00	10.65	0.30
09	Tight	Colr	19.17	0.54	3960.00	10.65	0.30
09	Tight	Mnvl;Jur	21.12	0.59	3583.83	10.94	0.31
10	Conventional	Mnvl;UprDvn	7.68	0.22	2692.26	18.88	0.53
11	Conventional	UprColr	10.65	0.30	4000.00	17.75	0.50
11	Conventional	Colr;UprMnvl	10.65	0.30	4032.82	17.75	0.50
11	Conventional	MdlMnvl;LwrMnvl	7.81	0.22	5000.00	17.75	0.50
11	Conventional	UprTri	7.81	0.22	5000.00	25.12	0.71
11	Conventional	LwrTri	7.81	0.22	4500.00	26.42	0.74
11	Conventional	Miss	7.81	0.22	5000.00	22.99	0.65
11	Conventional	UprDvn;MdlDvn	8.87	0.25	6000.00	23.04	0.65
11	Tight	UprColr	10.65	0.30	4000.00	17.75	0.50
11	Tight	MdlMnvl;LwrMnvl	10.65	0.30	4050.00	17.75	0.50
12	Conventional	Mnvl	8.56	0.24	4439.71	17.78	0.50
12	Conventional	Miss	12.05	0.34	5151.16	27.39	0.77
12	Conventional	UprDvn	12.43	0.35	5514.04	36.44	1.03
12	Conventional	MdlDvn	11.28	0.32	6053.42	39.74	1.12

Area	Resource Type	Resource Group	Variable Operating Cost $\$/10^3m^3$	Variable Operating Cost \$/mcf	Fixed Operating Cost \$/month	Processing Cost $\$/10^3m^3$	Processing Cost \$/mcf
13	Conventional	Colr	16.51	0.47	3550.00	10.65	0.30
13	Conventional	LwrTri	17.88	0.50	4450.00	12.42	0.35
13	Tight	Colr	16.51	0.47	3550.00	10.65	0.30
13	Tight	Mnvl	17.26	0.49	4069.35	10.65	0.30
13	Tight	LwrTri	17.26	0.49	4450.00	14.20	0.40
14	Conventional	Mnvl	15.97	0.45	2400.00	33.19	0.94
14	Conventional	Tri	15.97	0.45	4500.00	33.92	0.96
14	Conventional	Perm;Miss	15.97	0.45	7200.00	31.94	0.90
14	Conventional	UprDvn;MdlDvn	15.97	0.45	4400.00	31.05	0.87
14	Tight	Tri	15.97	0.45	4500.00	32.89	0.93
14	Tight	Perm;Miss	15.97	0.45	5200.00	33.72	0.95
15	Conventional	LwrMnvl	9.92	0.28	3500.00	29.28	0.83
15	Conventional	Perm;Miss	9.97	0.28	3800.00	26.62	0.75
15	Conventional	UprDvn;MdlDvn	14.20	0.40	4500.00	29.28	0.83
15	Tight	UprDvn	9.88	0.28	3800.00	26.62	0.75
15	Shale	Shale	9.88	0.28	3800.00	26.62	0.75
16	Conventional	Colr;Mnvl	14.86	0.42	3975.00	7.99	0.23
16	Conventional	Tri;Perm;Miss	13.63	0.38	4723.03	7.99	0.23
17	Tight	UprColr	9.44	0.27	1125.00	21.30	0.60
18	Conventional	Colr	10.04	0.28	1775.00	21.30	0.60
18	Conventional	MdlMnvl;LwrMnvl;Miss	10.46	0.29	2368.60	28.12	0.79

Appendix 12 – 2009 Rate of Return

Rate of Return with 100% success rate

Area	Resource Type	Resource Group	Alberta NIT Gas Prices (2009C$/GJ) $3 gas	$4 gas	$5 gas	$6 gas	$7 gas	$8 gas	$9 gas	$10 gas	$11 gas	$12 gas	Supply Cost at 15%	Payout Years
00	CBM	Main HSC	#N/A	#N/A	#N/A	#N/A	0.0977	0.16634	0.22636	0.274	0.32021	0.37128	7.75	6.04
00	CBM	Mannville	#N/A	0.00382	0.078869	0.134796	0.180639	0.224309	0.264149	0.300919	0.337959	0.38515	6.31	5.26
01	Conventional	Tert;UprCret;UprColr	#N/A	#N/A	-0.00071	0.1678	0.2914	0.4158	0.54341	0.6638	0.7805	0.9327	5.86	5.29
01	Conventional	Colr	#N/A	#N/A	#N/A	#N/A	#N/A	0.00047	0.08733	0.14714	0.19661	0.253	10.05	4.55
01	Conventional	Mnvl	#N/A	#N/A	0.10027	0.20892	0.30342	0.39846	0.4896	0.57696	0.66455	0.77984	5.44	5.09
01	Tight	UprColr	#N/A	#N/A	#N/A	#N/A	0.08632	0.1808	0.26374	0.3392	0.40431	0.482	7.65	5.25
02	Conventional	Tert;UprCret;UprColr	#N/A	#N/A	#N/A	#N/A	#N/A	0.1009	0.21474	0.30274	0.3762	0.46481	8.39	6.1
02	Conventional	Colr	#N/A	#N/A	#N/A	0.17535	0.30075	0.43203	0.5663	0.69733	0.83471	1.0438	5.81	5.89
02	Conventional	MdlMnvl;LwrMnvl	#N/A	0.070159	0.23667	0.3808	0.5169	0.66475	0.8114	0.95262	1.11442	1.3597	4.45	4.81
02	Conventional	Jur;Miss	#N/A	#N/A	#N/A	#N/A	#N/A	0.02021	0.088719	0.1366	0.179809	0.22738	10.31	5.21
02	Tight	UprColr	#N/A	#N/A	#N/A	0.08215	0.20982	0.31415	0.41541	0.5069	0.59721	0.71181	6.47	6.12
02	Tight	Colr	#N/A	#N/A	0.03035	0.14869	0.24059	0.32897	0.41295	0.49091	0.57053	0.67393	6.01	5.62
02	Tight	LwrMnvl	#N/A	#N/A	#N/A	0.067429	0.15975	0.2418	0.31346	0.37795	0.4424	0.52302	6.88	4.78
03	Conventional	Miss;UprDvn	#N/A	#N/A	0.0232649	0.0875283	0.14251	0.1979162	0.250531	0.30673	0.3883741	0.478852	7.14	4.21
04	Conventional	UprCret;UprColr	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-0.02481	0.04061	14.39	4.89
04	Conventional	Colr;Mnvl	#N/A	#N/A	#N/A	#N/A	#N/A	-0.032	0.08623	0.16086	0.22327	0.29178	9.83	4.36
04	Tight	UprColr	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	23.47	5.35
05	Conventional	Tert;UprCret	#N/A	#N/A	#N/A	#N/A	-0.06327	0.07958	0.17014	0.2393	0.30055	0.372	8.77	4.48
05	Conventional	Colr	#N/A	#N/A	#N/A	#N/A	#N/A	0.03376	0.12407	0.18585	0.23978	0.29986	9.38	5.36
05	Conventional	Mnvl	#N/A	#N/A	#N/A	#N/A	#N/A	0.10856	0.20875	0.28835	0.36208	0.4524	8.39	4.17
05	Conventional	Miss;UprDvn	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0.016221	0.067329	0.1105	0.1545	11.9	4.93
05	Tight	Colr	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0.0386	0.10717	0.15727	0.20848	10.85	5.36
05	Tight	Mnvl	0.098219	0.31045	0.51425	0.72095	0.92772	1.17263	1.4323	1.6951	2.0766	2.7108	3.23	5.47
06	Conventional	Tert	#N/A	0.06343	0.29351	0.49464	0.6926	0.90971	1.13591	1.3683	1.6113	1.977	4.33	4.45
06	Conventional	UprCret;UprColr	#N/A	0.2504	0.51621	0.78511	1.0619	1.3957	1.7739	2.1935	2.6583	3.442	3.68	4.94
06	Conventional	Mnvl	#N/A	0.17797	0.37627	0.57265	0.7507	0.9534	1.1621	1.3689	1.6717	2.1297	3.88	4.17
06	Conventional	LwrMnvl;Jur	#N/A	0.07171	0.200229	0.304139	0.396939	0.49473	0.58958	0.67903	0.79506	0.95037	4.57	4.86
06	Conventional	Miss	#N/A	#N/A	0.069669	0.171748	0.253197	0.334449	0.4115	0.48391	0.58555	0.7148	5.75	4.67
06	Conventional	UprDvn	#N/A	#N/A	#N/A	0.14376	0.35797	0.6192	0.94194	1.27261	1.8345	2.7425	6.03	2.77
06	Tight	Colr	#N/A	0.20838	0.37503	0.53178	0.68057	0.8491	1.02142	1.19071	1.396	1.71471	3.68	5.28
06	Tight	Mnvl	#N/A	0.059449	0.199179	0.312589	0.41459	0.52278	0.63018	0.73388	0.85681	1.03011	4.61	5.1
07	Conventional	UprColr	#N/A	#N/A	0.042147	0.10693	0.160611	0.212952	0.261098	0.310318	0.38499	0.468939	6.79	4.97
07	Conventional	Colr;Mnvl	#N/A	#N/A	#N/A	#N/A	0.0073839	0.044634	0.075504	0.102624	0.137784	0.174488	11.33	4.88
07	Conventional	Jur;Tri;Perm	#N/A	#N/A	#N/A	0.0371759	0.0792211	0.116905	0.1493391	0.1846961	0.236286	0.292212	9.01	4.72
07	Conventional	Miss	#N/A	#N/A	#N/A	#N/A	0.043691	0.0993471	0.14811	0.196987	0.277387	0.36921	9.04	3.74
07	Conventional	UprDvn;MdlDvn	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0.026239	16.07	3.99
07	Tight	UprColr;Colr	#N/A	#N/A	#N/A	0.020847	0.06534	0.104257	0.1373081	0.1688341	0.212305	0.258449	9.42	4.92
07	Tight	Jur	#N/A	#N/A	#N/A	0.0235338	0.0701181	0.113738	0.150796	0.186356	0.242234	0.304535	8.08	4.52
08	Conventional	UprColr;Colr	#N/A	0.03936	0.16103	0.25416	0.33397	0.41605	0.49399	0.566029	0.65777	0.78046	4.9	4.86
08	Conventional	Mnvl;Jur	#N/A	#N/A	0.06661	0.179819	0.270449	0.36151	0.44728	0.52703	0.64652	0.80192	5.71	4.37
08	Conventional	Tri	#N/A	0.03619	0.18098	0.307	0.43	0.57445	0.72926	0.89203	1.18814	1.6252	4.76	4.8
08	Conventional	UprDvn	#N/A	0.058197	0.204186	0.337029	0.47271	0.63008	0.80336	0.995	1.29035	1.69471	4.61	4.67
08	Tight	Colr;Mnvl	#N/A	#N/A	0.01746	0.13448	0.223279	0.30859	0.38816	0.46252	0.56129	0.6888	6.16	4.37
09	Conventional	UprCret	#N/A	#N/A	#N/A	-0.03443	0.021563	0.065408	0.099477	0.12949	0.158365	0.192026	10.72	4.9
09	Conventional	UprColr	#N/A	#N/A	#N/A	0.036971	0.09869	0.153685	0.200916	0.243456	0.296149	0.359889	7.93	4.45
09	Conventional	Mnvl;Jur	#N/A	#N/A	#N/A	#N/A	0.004113	0.040854	0.071326	0.097768	0.123717	0.151994	11.93	4.94
09	Conventional	Tri	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0.0171	0.043131	0.074078	0.107083	13.31	4.48
09	Conventional	UprDvn	0.0841641	0.229194	0.371907	0.520065	0.65152	0.803059	0.952179	1.1088	1.41009	1.79441	3.45	4.43
09	Tight	UprColr	#N/A	#N/A	#N/A	-0.013118	0.030563	0.066859	0.097387	0.124117	0.152984	0.18585	10.91	5.14
09	Tight	Colr	#N/A	#N/A	0.068348	0.128169	0.174834	0.219458	0.259595	0.295779	0.344155	0.40169	6.45	5.01
09	Tight	Mnvl;Jur	#N/A	0.042267	0.113945	0.16972	0.216909	0.265144	0.309448	0.350308	0.412789	0.486485	5.62	5.17
10	Conventional	Mnvl;UprDvn	#N/A	#N/A	#N/A	#N/A	#N/A	0.08655	0.19288	0.27344	0.34885	0.43492	8.54	4.17
11	Conventional	UprColr	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-0.02129	0.021641	15.69	4.38
11	Conventional	Colr;UprMnvl	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-0.021169	0.04026	0.09179	0.14915	12.02	3.76

Groupings with estimated decline curves (hard to model production profile based on history) or newly developed groupings (not a lot of 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	Colr	$5.81	5.89	$7.20	4.28	62.5%	0.32	69
02 - Southwest AB	Conventional	Jur;Miss	$10.31	5.21	$10.31	5.21	100.0%	0.17	72
02 - Southwest AB	Tight	Colr	$6.01	5.62	$7.30	5.99	65.0%	0.15	75
02 - Southwest AB	Tight	LwrMnvl	$6.88	4.78	$6.88	4.79	99.9%	0.51	65
03 - Southern Foothills	Conventional	Miss;UprDvn	$7.14	4.21	$8.51	4.25	80.0%	0.10	78
06 - West Central AB	Conventional	Mnvl	$3.88	4.17	$3.88	4.17	100.0%	0.12	77
06 - West Central AB	Conventional	Miss	$5.75	4.67	$5.84	4.71	95.0%	1.93	40
06 - West Central AB	Conventional	UprDvn	$6.03	2.77	$6.73	2.99	75.0%	1.55	45
06 - West Central AB	Tight	Colr	$3.68	5.28	$3.77	5.28	91.7%	0.36	68
07 - Central Foothills	Conventional	UprColr	$6.79	4.97	$7.70	5.06	75.0%	2.04	39
07 - Central Foothills	Conventional	Jur;Tri;Perm	$9.01	4.72	$9.07	4.72	99.0%	1.74	42
07 - Central Foothills	Tight	UprColr;Colr	$9.42	4.92	$9.42	4.92	100.0%	0.28	70
07 - Central Foothills	Tight	Jur	$8.08	4.52	$8.08	4.52	100.0%	2.45	36
08 - Kaybob	Conventional	UprDvn	$4.61	4.67	$4.76	4.78	93.0%	1.48	47
09 - AB Deep Basin	Conventional	UprDvn	$3.45	4.43	$4.12	4.57	75.0%	1.14	54
09 - AB Deep Basin	Tight	Colr	$6.45	5.01	$6.81	5.07	92.0%	3.38	32
11 - Peace River	Conventional	UprTri	$7.74	4.53	$7.92	4.56	96.0%	0.49	66
11 - Peace River	Conventional	Miss	$5.80	4.58	$5.80	4.58	100.0%	2.62	35
11 - Peace River	Conventional	UprDvn;MdlDvn	$26.33	4.23	$34.92	4.42	62.5%	0.21	71
11 - Peace River	Tight	UprColr	$11.86	4.54	$12.10	4.59	95.0%	0.04	82.00
11 - Peace River	Tight	MdlMnvl;LwrMnvl	$14.90	4.44	$15.40	4.45	95.0%	0.01	86.00
12 - Northwest AB	Conventional	Mnvl	$7.18	4.33	$7.18	4.33	100.0%	0.83	58
12 - Northwest AB	Conventional	Miss	$20.44	4.37	$20.44	4.37	100.0%	0.16	74
12 - Northwest AB	Conventional	UprDvn	$6.62	3.98	$6.93	4.08	87.5%	1.50	46
13 - BC Deep Basin	Conventional	Colr	$18.40	4.81	$32.10	5.05	50.0%	0.16	73
13 - BC Deep Basin	Tight	Colr	$7.32	4.92	$7.32	4.92	100.0%	0.70	61
14 - Fort St. John	Conventional	Perm;Miss	$4.11	4.26	$4.11	4.26	100.0%	2.18	38
14 - Fort St. John	Conventional	UprDvn;MdlDvn	$3.62	4.22	$3.62	4.22	100.0%	1.14	55
14 - Fort St. John	Tight	Perm;Miss	$6.69	4.83	$6.69	4.83	100.0%	0.73	59.00
15 - Northeast BC	Conventional	LwrMnvl	$25.49	5.54	$25.49	5.54	100.0%	0.01	85
15 - Northeast BC	Conventional	Perm;Miss	$13.90	4.96	$13.90	4.96	100.0%	0.03	83
15 - Northeast BC	Conventional	UprDvn;MdlDvn	$13.35	4.99	$13.81	5.01	95.0%	0.02	84
15 - Northeast BC	Shale	MdlDvn	$4.68	5.73	$4.68	5.73	100.0%	33.47	2
16 - BC Foothills	Conventional	Tri;Perm;Miss	$4.72	5.08	$4.75	5.08	99.0%	9.38	13
Production-Weighted Averages (and Total Production):			**$5.43**	**5.17**	**$5.59**	**5.18**	**96.7%**	**71.41**	**21**

Rate of Return with various success rates

Area	Resource Type	Resource Group	Alberta NIT Gas Prices (2009C$/GJ)										Supply Cost at 15%	Payout Years
			$3 gas	$4 gas	$5 gas	$6 gas	$7 gas	$8 gas	$9 gas	$10 gas	$11 gas	$12 gas		
00	CBM	Main HSC	#N/A	#N/A	#N/A	#N/A	0.0977	0.16634	0.22636	0.274	0.32021	0.37128	7.75	6.04
00	CBM	Mannville	#N/A	0.00382	0.078869	0.134796	0.180639	0.224309	0.264149	0.300919	0.337959	0.38515	6.31	5.26
01	Conventional	Tert;UprCret;UprColr	#N/A	#N/A	-0.00121	0.16766	0.29121	0.41552	0.544	0.6633	0.77	0.933	5.86	5.29
01	Conventional	Colr	#N/A	#N/A	#N/A	#N/A	#N/A	-0.0289	0.07196	0.13381	0.18266	0.23677	10.34	4.6
01	Conventional	Mnvl	#N/A	#N/A	0.0785	0.18387	0.27653	0.3658	0.45081	0.53157	0.61257	0.71831	5.65	5.19
01	Tight	UprColr	#N/A	#N/A	#N/A	#N/A	0.08532	0.181	0.26273	0.33811	0.404	0.48053	7.66	5.25
02	Conventional	Tert;UprCret;UprColr	#N/A	#N/A	#N/A	#N/A	#N/A	0.08161	0.20144	0.28846	0.36011	0.44572	8.52	6.19
02	Conventional	Colr	#N/A	#N/A	#N/A	#N/A	0.13174	0.2245	0.31204	0.39122	0.46871	0.578	7.2	6.1
02	Conventional	MdlMnvl;LwrMnvl	#N/A	0.06123	0.22678	0.36823	0.50075	0.64413	0.786	0.92234	1.079	1.3127	4.5	4.85
02	Conventional	Jur;Miss	#N/A	#N/A	#N/A	#N/A	#N/A	0.02021	0.088719	0.1366	0.179809	0.22738	10.31	5.21
02	Tight	UprColr	#N/A	#N/A	#N/A	0.08181	0.20957	0.31386	0.41505	0.50653	0.59671	0.71121	6.47	6.13
02	Tight	Colr	#N/A	#N/A	#N/A	0.04625	0.12963	0.19588	0.25584	0.30962	0.36486	0.43505	7.3	5.99
02	Tight	LwrMnvl	#N/A	#N/A	#N/A	0.06715	0.159449	0.24144	0.31312	0.37756	0.44206	0.52251	6.88	4.79
03	Conventional	Miss;UprDvn	#N/A	#N/A	#N/A	0.0375578	0.083438	0.1283361	0.1712421	0.2175492	0.2839041	0.355066	8.51	4.25
04	Conventional	UprCret;UprColr	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-0.0393	0.03225	14.57	4.93
04	Conventional	Colr;Mnvl	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0.07266	0.14817	0.21	0.277	10.03	4.4
04	Tight	UprColr	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	24.21	5.44
05	Conventional	Tert;UprCret	#N/A	#N/A	#N/A	#N/A	-0.06811	0.07763	0.16841	0.23757	0.29855	0.36876	8.79	4.49
05	Conventional	Colr	#N/A	#N/A	#N/A	#N/A	#N/A	0.02796	0.12023	0.18199	0.23565	0.2951	9.43	5.37
05	Conventional	Mnvl	#N/A	#N/A	#N/A	#N/A	#N/A	0.01153	0.12926	0.20827	0.27555	0.35281	9.25	4.44
05	Conventional	Miss;UprDvn	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-0.001889	0.05125	0.09419	0.136909	12.31	4.99
05	Tight	Colr	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0.03823	0.10698	0.15709	0.20829	10.86	5.36
05	Tight	Mnvl	0.085209	0.29311	0.48731	0.68251	0.87622	1.10372	1.34281	1.5826	1.9246	2.4819	3.29	5.56
06	Conventional	Tert	#N/A	0.05206	0.28271	0.4795	0.67251	0.88321	1.1018	1.3256	1.5589	1.9073	4.37	4.48
06	Conventional	UprCret;UprColr	#N/A	0.22053	0.47265	0.7208	0.97281	1.27131	1.6036	1.9657	2.35	3.0039	3.76	5.14
06	Conventional	Mnvl	#N/A	0.17797	0.37627	0.57265	0.7507	0.9534	1.1621	1.3689	1.6717	2.1297	3.88	4.17
06	Conventional	LwrMnvl;Jur	#N/A	0.062019	0.190179	0.291589	0.38156	0.47588	0.56708	0.65291	0.76355	0.91095	4.65	4.9
06	Conventional	Miss	#N/A	-0.117257	0.06288	0.16445	0.244919	0.3243	0.399649	0.47008	0.56861	0.69363	5.84	4.71
06	Conventional	UprDvn	#N/A	#N/A	#N/A	0.0081	0.19973	0.40327	0.62852	0.84721	1.18271	1.6607	6.73	2.99
06	Tight	Colr	#N/A	0.19042	0.35306	0.50188	0.64204	0.7996	0.95971	1.116	1.305	1.59191	3.77	5.28
06	Tight	Mnvl	#N/A	0.052029	0.191629	0.302879	0.40242	0.50755	0.61167	0.71203	0.8305	0.998	4.67	5.14
07	Conventional	UprColr	#N/A	#N/A	0.0098169	0.070611	0.1186631	0.16339	0.203626	0.244377	0.304253	0.370397	7.7	5.06
07	Conventional	Colr;Mnvl	#N/A	#N/A	#N/A	#N/A	0.0037669	0.041031	0.071628	0.0984941	0.133313	0.169165	11.47	4.89
07	Conventional	Jur;Tri;Perm	#N/A	#N/A	#N/A	0.0357638	0.0775211	0.115251	0.14748	0.182611	0.233788	0.289234	9.07	4.72
07	Conventional	Miss	#N/A	#N/A	#N/A	#N/A	#N/A	0.04531	0.0875471	0.1295341	0.193725	0.265607	10.34	3.79
07	Conventional	UprDvn;MdlDvn	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0.026239	16.07	3.99
07	Tight	UprColr;Colr	#N/A	#N/A	#N/A	0.020847	0.06534	0.104257	0.1373081	0.1688341	0.212305	0.258449	9.42	4.92
07	Tight	Jur	#N/A	#N/A	#N/A	0.0465469	0.0975871	0.145904	0.187854	0.228382	0.294113	0.36847	8.08	4.52
08	Conventional	UprColr;Colr	#N/A	#N/A	0.073929	0.15236	0.215289	0.27676	0.33444	0.3885	0.45207	0.53154	5.97	5.16
08	Conventional	Mnvl;Jur	#N/A	#N/A	0.0435	0.156278	0.242689	0.32778	0.407089	0.48048	0.58865	0.72797	5.93	4.45
08	Conventional	Tri	#N/A	0.023402	0.16587	0.28618	0.40212	0.53654	0.6793	0.82834	1.09441	1.47964	4.87	4.84
08	Conventional	UprDvn	#N/A	0.03983	0.18044	0.30415	0.42832	0.57036	0.72482	0.89264	1.14797	1.4885	4.76	4.78
08	Tight	Colr;Mnvl	#N/A	#N/A	-0.002088	0.11594	0.2021	0.28347	0.35844	0.42819	0.51973	0.63708	6.37	4.42
09	Conventional	UprCret	#N/A	#N/A	#N/A	#N/A	0.008937	0.052254	0.085807	0.114838	0.142589	0.174517	11.24	4.92
09	Conventional	UprColr	#N/A	#N/A	#N/A	0.032161	0.093708	0.148215	0.19482	0.23672	0.288436	0.350838	8.02	4.48
09	Conventional	Mnvl;Jur	#N/A	#N/A	#N/A	#N/A	0.004113	0.040854	0.071326	0.097768	0.123717	0.151994	11.93	4.94
09	Conventional	Tri	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0.0171	0.043131	0.074078	0.107083	13.31	4.48
09	Conventional	UprDvn	0.027014	0.137001	0.24289	0.349839	0.439593	0.539368	0.634397	0.735119	0.91431	1.12734	4.12	4.57
09	Tight	UprColr	#N/A	#N/A	#N/A	#N/A	0.027552	0.063533	0.093896	0.120336	0.148803	0.181088	11.03	5.15
09	Tight	Colr	#N/A	#N/A	0.05447	0.112266	0.158237	0.201314	0.23935	0.27359	0.318865	0.372369	6.81	5.07
09	Tight	Mnvl;Jur	#N/A	0.032951	0.102853	0.157856	0.203119	0.249006	0.29115	0.32992	0.388636	0.457949	5.84	5.2
10	Conventional	Mnvl;UprDvn	#N/A	#N/A	#N/A	#N/A	#N/A	0.02624	0.13972	0.22064	0.29207	0.37045	9.12	4.33
11	Conventional	UprColr	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-0.032269	17.79	4.54

Rate of Return with various success rates

Area	Resource Type	Resource Group	Alberta NIT Gas Prices (2009C$/GJ)										Supply Cost at 15%	Payout Years
			$3 gas	$4 gas	$5 gas	$6 gas	$7 gas	$8 gas	$9 gas	$10 gas	$11 gas	$12 gas		
11	Conventional	Colr;UprMnvl	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0.02269	0.07958	13.38	3.89
11	Conventional	MdlMnvl;LwrMnvl	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-0.005719	0.032561	0.068048	0.105778	13.23	4.5
11	Conventional	UprTri	#N/A	#N/A	-0.068009	0.031702	0.09746	0.154129	0.201896	0.243945	0.298169	0.36322	7.92	4.56
11	Conventional	LwrTri	#N/A	-0.04932	0.057548	0.134024	0.19529	0.255867	0.311427	0.362679	0.44108	0.535759	6.24	4.72
11	Conventional	Miss	#N/A	-0.058007	0.0749	0.1667	0.242348	0.318459	0.39093	0.45922	0.55998	0.689	5.8	4.58
11	Conventional	UprDvn;MdlDvn	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	34.92	4.42
11	Tight	UprColr	#N/A	#N/A	#N/A	#N/A	#N/A	-0.02025	0.030764	0.070659	0.106889	0.145617	12.1	4.59
11	Tight	MdlMnvl;LwrMnvl	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0.0085	0.04432	15.4	4.45
12	Conventional	Mnvl	#N/A	#N/A	-0.05884	0.05503	0.136689	0.206739	0.26666	0.32015	0.37135	0.43434	7.18	4.33
12	Conventional	Miss	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	20.44	4.37
12	Conventional	UprDvn	#N/A	#N/A	#N/A	0.03873	0.15614	0.25748	0.34585	0.42598	0.53234	0.66884	6.93	4.08
12	Conventional	MdlDvn	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0.022161	0.09661	0.16885	11.74	4.21
13	Conventional	Colr	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	32.1	5.05
13	Conventional	LwrTri	-0.123463	0.003353	0.076314	0.143686	0.215505	0.294453	0.383366	0.48502	0.594568	0.71872	6.09	4.26
13	Tight	Colr	#N/A	#N/A	0.014695	0.073236	0.130834	0.192159	0.26022	0.3377	0.4278	0.52851	7.32	4.92
13	Tight	Mnvl	#N/A	-0.0228911	0.036888	0.093127	0.151136	0.215315	0.286684	0.369224	0.466359	0.582497	6.98	4.89
13	Tight	LwrTri	#N/A	#N/A	-0.0159171	0.0342238	0.082575	0.1315881	0.18298	0.237621	0.296502	0.360405	8.36	4.39
14	Conventional	Mnvl	#N/A	#N/A	#N/A	#N/A	0.001733	0.054585	0.09986	0.142798	0.185878	0.22979	10.17	5.03
14	Conventional	Tri	#N/A	0.021852	0.133667	0.239679	0.354598	0.48622	0.638489	0.821	1.03513	1.29519	5.15	5.01
14	Conventional	Perm;Miss	-0.08604	0.128869	0.311529	0.526929	0.80337	1.18502	1.75211	2.6915	4.4221	7.764	4.11	4.26
14	Conventional	UprDvn;MdlDvn	0.049117	0.215753	0.40065	0.629859	0.91416	1.2813	1.79132	2.555	3.8304	6.428	3.62	4.22
14	Tight	Tri	0.031249	0.160544	0.296518	0.446973	0.618379	0.819479	1.05978	1.352709	1.718289	2.18789	3.92	4.94
14	Tight	Perm;Miss	#N/A	-0.0340523	0.040551	0.1055551	0.17065	0.241926	0.317077	0.399027	0.489164	0.58869	6.69	4.83
15	Conventional	LwrMnvl	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	25.49	5.54
15	Conventional	Perm;Miss	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0.011674	0.041638	0.070037	0.0977821	13.9	4.96
15	Conventional	UprDvn;MdlDvn	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0.0167249	0.0446619	0.0714651	0.09925	13.81	5.01
15	Tight	UprDvn	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0.017258	18.49	4.88
15	Shale	Shale	0.0324003	0.100736	0.175312	0.2627171	0.368562	0.498547	0.660439	0.865445	1.130619	1.483509	4.68	5.73
16	Conventional	Colr;Mnvl	#N/A	#N/A	#N/A	0.012175	0.0557581	0.097014	0.134237	0.172109	0.211118	0.250425	9.42	4.59
16	Conventional	Tri;Perm;Miss	0.024305	0.0957881	0.169228	0.248115	0.33728	0.439134	0.55446	0.682684	0.82868	0.99596	4.75	5.08
17	Tight	UprColr	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-0.015	0.06602	0.12703	0.18221	11.42	4.98
18	Conventional	Colr	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	23.75	4.66
18	Conventional	MdlMnvl;LwrMnvl;Miss	#N/A	#N/A	#N/A	-0.05682	0.066669	0.31494	0.43045	0.55461	0.6913	0.84392	7.92	4.65

Appendix 13 – 2007 versus 2009 Comparison of Key Values

Area	Resource Type	Resource Group	Supply Cost at 15% (risked) 2007	Supply Cost at 15% (risked) 2009	Drill & Comp Cost Thousands C$ 2007	Drill & Comp Cost Thousands C$ 2009	Initial Production mmcf/d 2007	Initial Production mmcf/d 2009	Production Bcf in 2007 2007 wells	Production Bcf in 2009 2009 wells
00	CBM	Main HSC	6.53	7.75	295	310	0.08	0.08	28.70	22.37
00	CBM	Mannville	5.65	6.31	1080	1239	0.38	0.27	4.07	1.56
01	Conventional	Tert;UprCret;UprColr	11.53	5.86	262	185	0.08	0.10	7.38	3.39
01	Conventional	Colr	14.58	10.34	404	400	0.13	0.13	5.61	1.17
01	Conventional	Mnvl	6.27	5.65	545	511	0.30	0.28	10.61	5.07
01	Tight	UprColr	9.19	7.66	217	208	0.08	0.07	33.34	19.08
02	Conventional	Tert;UprCret;UprColr	8.55	8.52	227	236	0.13	0.10	4.18	1.41
02	Conventional	Colr	11.41	7.20	462	480	0.16	0.51	0.25	0.32
02	Conventional	MdlMnvl;LwrMnvl	5.15	4.50	587	678	0.62	0.54	5.41	1.60
02	Conventional	Jur;Miss	7.65	10.31	696	735	0.34	0.22	0.26	0.17
02	Tight	UprColr	22.84	6.47	257	270	0.06	0.12	0.27	0.12
02	Tight	Colr	17.47	7.30	464	504	0.11	0.25	0.09	0.15
02	Tight	LwrMnvl	3.48	6.88	601	668	0.50	0.24	3.64	0.51
03	Conventional	Miss;UprDvn	8.39	8.51	13277	15815	3.40	5.80	0.75	0.10
04	Conventional	UprCret;UprColr	18.53	14.57	184	343	0.05	0.11	3.37	0.43
04	Conventional	Colr;Mnvl	8.76	10.03	386	418	0.18	0.18	21.74	8.49
04	Tight	UprColr	18.31	24.21	203	352	0.05	0.06	0.07	0.04
05	Conventional	Tert;UprCret	7.82	8.79	292	323	0.15	0.11	14.56	3.39
05	Conventional	Colr	10.18	9.43	657	435	0.16	0.16	2.89	0.68
05	Conventional	Mnvl	7.55	9.25	709	558	0.36	0.27	24.11	8.04
05	Conventional	Miss;UprDvn	12.54	12.31	1163	837	0.24	0.18	0.83	0.85
05	Tight	Colr	8.31	10.86	1004	439	0.26	0.12	1.15	0.73
05	Tight	Mnvl	8.26	3.29	1424	557	0.39	0.63	1.76	0.61
06	Conventional	Tert	7.31	4.37	276	250	0.18	0.23	7.49	4.13
06	Conventional	UprCret;UprColr	5.47	3.76	718	325	0.42	0.35	6.44	3.12
06	Conventional	Mnvl	19.61	3.88	1559	714	0.25	0.60	0.10	0.12
06	Conventional	LwrMnvl;Jur	10.19	4.65	1929	974	0.48	0.67	16.57	9.68
06	Conventional	Miss	10.12	5.84	2535	1300	0.57	0.85	2.36	1.93
06	Conventional	UprDvn	2.50	6.73	2656	1431	1.25	0.67	6.24	1.55
06	Tight	Colr	4.99	3.77	1323	639	0.44	0.55	2.12	0.36
06	Tight	Mnvl	7.57	4.67	1610	729	0.46	0.54	15.89	12.40
07	Conventional	UprColr	11.31	7.70	2403	3330	0.72	2.55	2.70	2.04
07	Conventional	Colr;Mnvl	10.74	11.47	3279	4015	1.05	1.70	6.91	8.66
07	Conventional	Jur;Tri;Perm	3.72	9.07	5345	6069	5.70	3.00	11.87	1.74
07	Conventional	Miss	6.60	10.34	7098	7743	2.90	4.50	4.76	7.56
07	Conventional	UprDvn;MdlDvn	9.48	16.07	7954	8712	1.80	2.00	4.68	0.07
07	Tight	UprColr;Colr	12.12	9.42	3003	3769	0.65	1.70	1.44	0.28
07	Tight	Jur	12.24	8.08	5182	5154	1.75	3.00	4.20	2.45
08	Conventional	UprColr;Colr	9.64	5.97	980	897	0.46	0.72	0.93	1.02
08	Conventional	Mnvl;Jur	7.41	5.93	1486	1092	1.10	0.96	13.65	5.59
08	Conventional	Tri	7.14	4.87	2046	1316	1.10	1.58	10.30	9.95
08	Conventional	UprDvn	5.56	4.76	3323	1529	1.30	0.90	0.65	1.48
08	Tight	Colr;Mnvl	8.23	6.37	1408	1020	0.64	0.77	13.36	6.12
09	Conventional	UprCret	14.96	11.24	1505	1755	0.33	0.46	0.87	1.22
09	Conventional	UprColr	7.94	8.02	2146	1994	0.56	0.90	2.59	1.82
09	Conventional	Mnvl;Jur	9.94	11.93	2635	2552	0.64	0.50	1.97	3.41
09	Conventional	Tri	11.84	13.31	2836	3751	0.62	1.29	3.35	4.00
09	Conventional	UprDvn	3.97	4.12	6492	6325	6.50	4.19	3.24	1.14
09	Tight	UprColr	7.33	11.03	1646	2328	0.60	0.69	11.12	6.56
09	Tight	Colr	5.33	6.81	1815	2244	1.30	0.77	8.13	3.38
09	Tight	Mnvl;Jur	6.50	5.84	3200	2611	1.20	1.12	117.22	63.58
10	Conventional	Mnvl;UprDvn	9.44	9.12	384	380	0.19	0.18	15.21	5.16
11	Conventional	UprColr	4.86	17.79	568	954	0.55	0.23	1.14	0.06
11	Conventional	Colr;UprMnvl	6.41	13.38	807	1102	0.59	0.48	4.97	0.60
11	Conventional	MdlMnvl;LwrMnvl	10.98	13.23	1028	1465	0.58	0.59	8.34	2.20
11	Conventional	UprTri	8.56	7.92	1360	1683	0.70	1.07	2.00	0.49
11	Conventional	LwrTri	7.81	6.24	1515	2006	0.60	1.33	14.16	13.83
11	Conventional	Miss	6.63	5.80	1252	1545	0.85	1.25	4.58	2.62
11	Conventional	UprDvn;MdlDvn	15.97	34.92	1472	2332	0.80	0.40	1.12	0.21
11	Tight	UprColr	-	12.10	-	972	-	0.28	-	0.04
11	Tight	MdlMnvl;LwrMnvl	-	15.40	-	1526	-	0.50	-	0.01
12	Conventional	Mnvl	10.29	7.18	592	631	0.21	0.40	4.73	0.83
12	Conventional	Miss	19.38	20.44	743	676	0.27	0.16	2.43	0.16
12	Conventional	UprDvn	17.62	6.93	1042	931	0.68	1.13	1.23	1.50
12	Conventional	MdlDvn	12.23	11.74	1452	1424	0.53	1.15	1.92	2.89

Area	Resource Type	Resource Group	Supply Cost at 15% (risked) 2007	2009	Drill & Comp Cost Thousands C$ 2007	2009	Initial Production mmcf/d 2007	2009	Production Bcf in 2007 2007 wells	Bcf in 2009 2009 wells
13	Conventional	Colr	40.22	32.10	1725	2125	0.15	0.65	0.04	0.16
13	Conventional	LwrTri	5.89	6.09	4900	2650	2.20	1.70	7.72	12.77
13	Tight	Colr	4.52	7.32	1725	2125	1.30	2.20	1.59	0.70
13	Tight	Mnvl	7.30	6.98	5000	2531	2.70	2.60	20.74	12.20
13	Tight	LwrTri	-	8.36	-	5550	-	3.50		1.30
14	Conventional	Mnvl	8.93	10.17	1195	1355	0.43	0.35	16.24	4.60
14	Conventional	Tri	5.97	5.15	1730	1733	0.95	1.21	35.52	30.74
14	Conventional	Perm;Miss	4.71	4.11	2391	2010	2.10	1.81	3.68	2.18
14	Conventional	UprDvn;MdlDvn	5.62	3.62	4208	3139	2.30	2.30	1.28	1.14
14	Tight	Tri	-	3.92	-	5550	-	3.50	-	14.86
14	Tight	Perm;Miss	-	6.69	-	5950	-	2.25	-	0.73
15	Conventional	LwrMnvl	11.49	25.49	1328	935	0.22	0.17	0.00	0.01
15	Conventional	Perm;Miss	15.81	13.90	1195	787	0.22	0.77	1.14	0.03
15	Conventional	UprDvn;MdlDvn	7.11	13.81	3116	3358	1.66	1.25	1.36	0.02
15	Tight	UprDvn	8.74	18.49	3225	3630	1.16	1.10	27.48	4.25
15	Shale	MdlDvn	-	4.68	-	6424	-	6.00	-	33.47
16	Conventional	Colr;Mnvl	14.73	9.42	3938	4623	1.23	0.93	6.18	5.59
16	Conventional	Tri;Perm;Miss	9.16	4.75	4711	5278	1.69	2.40	10.86	9.38
17	Tight	UprColr	9.01	11.42	156	161	0.07	0.07	9.92	5.78
18	Conventional	Colr	15.40	23.75	384	385	0.09	0.09	1.30	1.38
18	Conventional	MdlMnvl;LwrMnvl;Miss	8.78	7.92	420	465	0.23	0.23	3.37	1.35
		Production-weighted averages:	**7.87**	**6.97**	**2024**	**2428**	**0.92**	**1.53**	**33.79**	**21.08**

Appendix 14 – 2009 Supply Cost Components

Supply Cost Components with 100% success rate

Area	Resource Type	Resource Group	Components - 2009C$/GJ					Supply Cost at 15%	Payout Years	Bcf in 2009 2009 wells
			Capital & Land	Operating & Processing	Royaly	Tax	Return			
00	CBM	Main HSC	2.86	2.77	0.37	0.59	1.15	7.75	6.04	22.37
00	CBM	Mannville	1.80	1.84	0.81	0.51	1.36	6.31	5.26	1.56
01	Conventional	Tert;UprCret;UprColr	2.23	2.46	0.26	0.33	0.57	5.86	5.29	3.39
01	Conventional	Colr	4.53	2.84	0.88	0.61	1.19	10.05	4.55	1.17
01	Conventional	Mnvl	1.98	2.04	0.41	0.32	0.69	5.44	5.09	5.07
01	Tight	UprColr	3.05	2.92	0.36	0.46	0.85	7.65	5.25	19.08
02	Conventional	Tert;UprCret;UprColr	3.64	3.40	0.42	0.48	0.44	8.39	6.1	1.41
02	Conventional	Colr	2.20	2.36	0.52	0.29	0.44	5.81	5.89	0.32
02	Conventional	MdlMnvl;LwrMnvl	1.32	2.04	0.49	0.20	0.40	4.45	4.81	1.60
02	Conventional	Jur;Miss	3.56	3.29	1.57	0.59	1.30	10.31	5.21	0.17
02	Tight	UprColr	2.43	2.91	0.29	0.36	0.48	6.47	6.12	0.12
02	Tight	Colr	2.09	2.47	0.35	0.36	0.73	6.01	5.62	0.15
02	Tight	LwrMnvl	2.59	2.39	0.67	0.40	0.83	6.88	4.78	0.51
03	Conventional	Miss;UprDvn	1.54	2.08	2.54	0.26	0.72	7.14	4.21	0.10
04	Conventional	UprCret;UprColr	5.55	4.71	1.62	0.82	1.68	14.39	4.89	0.43
04	Conventional	Colr;Mnvl	4.05	3.38	0.99	0.51	0.90	9.83	4.36	8.49
04	Tight	UprColr	8.41	7.19	2.71	1.56	3.60	23.47	5.35	0.04
05	Conventional	Tert;UprCret	3.49	3.36	0.51	0.49	0.91	8.77	4.48	3.39
05	Conventional	Colr	3.49	3.60	0.78	0.53	0.99	9.38	5.36	0.68
05	Conventional	Mnvl	3.30	2.89	1.17	0.40	0.62	8.39	4.17	8.04
05	Conventional	Miss;UprDvn	3.86	3.77	2.10	0.66	1.52	11.9	4.93	0.85
05	Tight	Colr	4.26	3.49	1.26	0.65	1.19	10.85	5.36	0.73
05	Tight	Mnvl	0.75	1.71	0.29	0.15	0.33	3.23	5.47	0.61
06	Conventional	Tert	1.59	1.97	0.23	0.22	0.32	4.33	4.45	4.13
06	Conventional	UprCret;UprColr	1.04	1.89	0.40	0.15	0.20	3.68	4.94	3.12
06	Conventional	Mnvl	1.32	1.83	0.24	0.17	0.32	3.88	4.17	0.12
06	Conventional	LwrMnvl;Jur	1.27	1.90	0.65	0.22	0.53	4.57	4.86	9.68
06	Conventional	Miss	1.48	2.22	1.22	0.24	0.60	5.75	4.67	1.93
06	Conventional	UprDvn	2.97	1.67	0.61	0.47	0.31	6.03	2.77	1.55
06	Tight	Colr	0.95	1.78	0.43	0.17	0.36	3.68	5.28	0.36
06	Tight	Mnvl	1.23	2.01	0.63	0.22	0.51	4.61	5.1	12.40
07	Conventional	UprColr	1.40	2.35	1.90	0.31	0.83	6.79	4.97	2.04
07	Conventional	Colr;Mnvl	2.44	2.75	4.20	0.52	1.41	11.33	4.88	8.66
07	Conventional	Jur;Tri;Perm	1.61	2.45	3.56	0.36	1.03	9.01	4.72	1.74
07	Conventional	Miss	2.01	2.32	3.74	0.27	0.69	9.04	3.74	7.56
07	Conventional	UprDvn;MdlDvn	4.10	2.83	6.96	0.60	1.58	16.07	3.99	0.07
07	Tight	UprColr;Colr	1.81	2.51	3.48	0.43	1.19	9.42	4.92	0.28
07	Tight	Jur	1.97	2.41	2.51	0.33	0.87	8.08	4.52	2.45
08	Conventional	UprColr;Colr	1.41	1.84	0.77	0.26	0.63	4.9	4.86	1.02
08	Conventional	Mnvl;Jur	1.53	2.15	1.28	0.23	0.52	5.71	4.37	5.59
08	Conventional	Tri	1.19	1.95	0.97	0.20	0.46	4.76	4.8	9.95
08	Conventional	UprDvn	1.20	1.87	0.92	0.18	0.43	4.61	4.67	1.48
08	Tight	Colr;Mnvl	1.75	2.16	1.41	0.27	0.58	6.16	4.37	6.12
09	Conventional	UprCret	3.01	2.37	2.93	0.65	1.75	10.72	4.9	1.22
09	Conventional	UprColr	2.59	1.85	2.10	0.40	0.99	7.93	4.45	1.82
09	Conventional	Mnvl;Jur	3.58	2.22	3.36	0.74	2.03	11.93	4.94	3.41
09	Conventional	Tri	3.57	2.03	5.44	0.62	1.66	13.31	4.48	4.00
09	Conventional	UprDvn	0.81	1.51	0.55	0.15	0.43	3.45	4.43	1.14
09	Tight	UprColr	2.85	2.15	3.37	0.68	1.87	10.91	5.14	6.56
09	Tight	Colr	1.90	1.65	1.44	0.39	1.06	6.45	5.01	3.38
09	Tight	Mnvl;Jur	1.54	1.55	1.16	0.36	1.00	5.62	5.17	63.58
10	Conventional	Mnvl;UprDvn	2.89	3.87	0.71	0.40	0.66	8.54	4.17	5.16
11	Conventional	UprColr	5.33	4.09	3.39	0.85	2.03	15.69	4.38	0.06
11	Conventional	Colr;UprMnvl	3.97	2.59	3.95	0.51	0.99	12.02	3.76	0.60
11	Conventional	MdlMnvl;LwrMnvl	3.48	2.66	3.44	0.56	1.38	11.53	4.4	2.20
11	Conventional	UprTri	2.22	2.13	2.10	0.36	0.92	7.74	4.53	0.49
11	Conventional	LwrTri	1.76	1.76	1.61	0.30	0.79	6.21	4.7	13.83
11	Conventional	Miss	1.72	1.82	1.31	0.27	0.67	5.8	4.58	2.62
11	Conventional	UprDvn;MdlDvn	8.55	4.80	8.76	1.22	3.00	26.33	4.23	0.21
11	Tight	UprColr	3.81	3.30	2.36	0.68	1.71	11.86	4.54	0.04
11	Tight	MdlMnvl;LwrMnvl	4.75	3.20	4.28	0.77	1.91	14.9	4.44	0.01

Supply Cost Components with 100% success rate

Area	Resource Type	Resource Group	Components - 2009C$/GJ					Supply Cost	Payout	Bcf in 2009
			Capital & Land	Operating & Processing	Royaly	Tax	Return	at 15%	Years	2009 wells
12	Conventional	Mnvl	2.47	2.30	1.08	0.41	0.92	7.18	4.33	0.83
12	Conventional	Miss	6.78	6.56	3.50	1.10	2.50	20.44	4.37	0.16
12	Conventional	UprDvn	1.91	2.40	1.58	0.26	0.46	6.62	3.98	1.50
12	Conventional	MdlDvn	3.43	3.09	3.98	0.43	0.81	11.74	4.21	2.89
13	Conventional	Colr	8.27	3.15	0.05	2.12	4.82	18.4	4.81	0.16
13	Conventional	LwrTri	2.24	1.67	0.35	0.54	1.22	6.01	4.26	12.77
13	Tight	Colr	2.72	1.46	1.06	0.66	1.42	7.32	4.92	0.70
13	Tight	Mnvl	2.56	1.64	0.61	0.65	1.48	6.95	4.88	12.20
13	Tight	LwrTri	2.90	1.29	2.15	0.61	1.40	8.36	4.39	1.30
14	Conventional	Mnvl	3.55	2.70	0.97	0.87	1.99	10.07	5.03	4.60
14	Conventional	Tri	1.23	2.02	0.90	0.30	0.70	5.14	4.99	30.74
14	Conventional	Perm;Miss	1.11	2.11	0.30	0.19	0.40	4.11	4.26	2.18
14	Conventional	UprDvn;MdlDvn	0.93	1.80	0.24	0.19	0.46	3.62	4.22	1.14
14	Tight	Tri	0.75	1.56	0.81	0.22	0.58	3.92	4.94	14.86
14	Tight	Perm;Miss	1.62	1.96	1.45	0.47	1.20	6.69	4.83	0.73
15	Conventional	LwrMnvl	6.16	6.32	0.59	3.47	8.93	25.49	5.54	0.01
15	Conventional	Perm;Miss	4.66	2.78	1.90	1.36	3.19	13.9	4.96	0.03
15	Conventional	UprDvn;MdlDvn	4.15	2.45	2.74	1.16	2.86	13.35	4.99	0.02
15	Tight	UprDvn	6.66	2.81	2.75	1.75	4.27	18.24	4.87	4.25
15	Shale	Shale	0.75	1.33	1.00	0.44	1.16	4.68	5.73	33.47
16	Conventional	Colr;Mnvl	3.90	1.75	0.19	1.00	2.49	9.32	4.58	5.59
16	Conventional	Tri;Perm;Miss	1.15	1.18	0.91	0.41	1.07	4.72	5.08	9.38
17	Tight	UprColr	4.77	3.89	0.15	1.05	1.57	11.42	4.98	5.78
18	Conventional	Colr	11.06	6.95	0.49	2.02	3.23	23.75	4.66	1.38
18	Conventional	MdlMnvl;LwrMnvl;Miss	2.65	2.77	1.10	0.52	0.87	7.92	4.65	1.35
		Production-weighted averages:	**2.08**	**2.10**	**1.18**	**0.44**	**1.01**	**6.81**	**4.97**	**21.08**