Technical Royalty Report OG#2:
Alberta's Conventional Oil and Gas Industry
- Investor Economics and Fiscal System Comparison -

This report is a technical report by the Alberta Department of Energy (ADOE). The technical report series is intended to contribute to the public understanding of oil and gas royalty issues.

Section I - Introduction

This report – Technical Report OG#2 - is the second in a series of technical reports describing the fiscal system and related economics issues for Alberta's conventional oil and natural gas. The purpose of these reports is to provide information and to invite comment as part of the Government of Alberta's public review of the royalties and taxes applied to the province's oil and gas resources. The first report described the status of Alberta's conventional oil and gas industry in terms of reserves, pool sizes, well productivities, and costs. Other reports provide information on the Alberta oil sands industry.

The present report: (a) provides an assessment of the economic attractiveness of Alberta's conventional oil and natural gas resources, (b) describes the fiscal system's performance across a wide range of possible economic outcomes, and (c) compares the results of this analysis to that for other comparable jurisdictions.

The report is divided into six sections. Section II provides the methodology and assumptions. Section III provides the analysis results in terms of industry returns and profitability. Section IV assesses the economics in terms of the shares to governments on behalf of resource owners – Albertans. Section V provides the inter-jurisdictional comparisons of government shares. Section VI provides a summary of findings and observations.

Section II - Methodology and Assumptions

The analysis for this report is full cycle and full risk; that is, all costs are taken into account including both successful and unsuccessful exploration.

The analysis looks at two levels of detail, first at a detailed regional level and then at an aggregate provincial level. The province was divided into seven regions to reflect varying resource conditions. These seven regions were first introduced by the PSAC.[1] Detail on the resource characteristics such as production volumes and wells drilled, for each PSAC region was provided in Technical Report OG#1. Table 2.1 below shows the shares of drilling between oil and natural gas by PSAC area. Natural gas drilling is shown to dominate, accounting for almost 90% of successful wells.

[1] The Petroleum Services Association of Canada (PSAC) originally divided Alberta into seven regions based on service areas with similar costs. This convention has continued as information remains readily available on a regional basis. In addition, the resources within regions tend to be relatively similar. Two of the regions, PSAC 1 and PSAC 6, were not analyzed for conventional oil. PSAC 1 has very few wells, with the overwhelming majority being natural gas. The oil contained within PSAC 6 is predominantly bitumen and subject to the Generic Oil Sands Royalty Regime.

TABLE 2.1 – ALBERTA SUCCESSFUL WELLS BY REGION (2005)

	PSAC 1	PSAC 2	PSAC 3	PSAC 4	PSAC 5	PSAC 6	PSAC 7	TOTAL
Oil Wells*	6	319	361	470	335	1	348	1,840
Oil Share	10%	15%	5%	45%	12%	1%	29%	13%
Gas Wells	54	1,809	6,268	563	2,435	159	859	12,147
Gas Share	90%	85%	95%	55%	88%	99%	71%	87%

*Does not include bitumen wells

To facilitate presentation and management of analysis results ADOE derived representative or "typical" wells from a detailed assessment of the many thousands of wells drilled over time in Alberta. The process for selecting these wells is described in detail in Appendix I.[2] Results were generated for three well-types in each PSAC area, representing the wells at the 90th percentile, the median, and the 10th percentile. Following accepted practice for such analysis, these well-types were then aggregated to create a mean or average value for each area using Swanson's Rule[3].

Having determined the appropriate reserves sizes for each PSAC area the next step was to reflect expectations and a prudent planning range for commodity prices. Three broad price levels were examined for both oil and natural gas.[4] First, a reference case of $50 per barrel (bbl) for oil and $6.75 per thousand cubic feet (Mcf) of natural gas was chosen based on current expectations as shown in Appendix III.[5] Following the traditional scenario approach for project economics assessment, these prices were supplemented with sensitivities of $30/bbl for oil and $3.50/Mcf for gas to form a low case and $75/bbl oil and $9/Mcf gas to form a high case. This range was selected to be broad enough to test the robustness of results.

The costs attached to each typical well were derived based on drilling patterns, analysis, and trends completed for Technical Report OG#1. The specific costs applied reflect the geologic and operating conditions for each area of Alberta. Costs were also adjusted to reflect the various price scenarios based on the price responsiveness of costs identified in Technical Report OG#1. The details for the costs employed are available in Appendix II. An important consideration in the costs is the chance of success. In general the chance of commercial success in Alberta is very high averaging close to 80%.

Following the determination of economics for each PSAC area these results are then weighted by production and drilling activity to arrive at weighted average results for Alberta as a whole.

The Royalty terms applied were "Third Tier" for oil and "New Gas" for natural gas. Details of these royalty terms are available in "Oil & Gas Fiscal Regimes of the Western Canadian

[2] The number of oil and gas wells being drilled on an annual basis in Alberta creates a large hurdle to overcome in assessing the results of these wells from an economics perspective. Data from these wells however affords a tremendous source of information.

[3] The use of Swanson's Rule is accepted in the oil and gas industry. Swanson's Rule represents the theoretical rationale for determining the appropriate probabilities as it provides a good approximation to the mean values for modestly skewed distributions. Swanson's Rule defines the mean as 0.30 x P10 + 0.40 x P50 + 0.30 x P90, where P10, P50, and P90 are pool sizes at the 10%, 50%, and 90% probabilities and 0.30, 0.40 and 0.30 are distributional weightings to adjust for the skewness of the distribution. "Swanson's 30-40-30 rule", A. Hurst, G.C. Brown, and R.I. Swanson, AAPG Bulletin, V. 84, No. 12 (December 2000), PP. 1883-1891.

[4] All prices and dollar amounts in this report are presented in real Canadian dollar terms.

[5] The price quoted for oil is an Alberta field price. For natural gas the prices quoted are at the AECO hub.

Provinces and Territories" available from at the ADOE website.[6] Normal corporate income tax rules were also applied. The assumed rates were 20% Federal and 10% Alberta.

The primary decision-making criteria employed to judge investment attractiveness is the expected monetary value (EMV)[7]; that is, the fully risked net present value (NPV). From the EMV two additional common industry decision-making benchmarks were also applied: the EMV per barrel of oil equivalent (EMV_{10}/Boe) which is the EMV results divided by total expected production, and the profitability ratio (PFR_{10})[8]. An attractive investment is characterized as having a positive EMV at the selected discount rate.

In addition to the EMV-related decision-making criteria internal rate of return (IRR) was also considered. Minimal reliance was placed on IRR as this measure is susceptible to a number of technical issues such as multiple roots or solutions depending on the nature of the cash flows. In addition IRR is very sensitive to the level and timing of investments; for example, a small project that achieves production in the same year as investments are made might have an infinite rate of return whereas a larger more costly project with higher net revenues may have a lower rate of return. Despite these difficulties rate of return is one of the commonly used indicators to evaluate investment alternatives.

Government share results are presented as the combined amounts paid to both the federal and provincial/state levels of government. Again following accepted industry practice, the share is expressed as a percent of net operating revenue.[9] Payments to government include royalties, land bonus, and both federal and provincial corporate income tax. Government share results are presented on an undiscounted basis to facilitate comparison with other jurisdictions.

Section III – Industry Returns and Profitability

This section presents the EMV economics results, first for natural gas and then for conventional oil. The weighted average prices resulting from the probabilities assigned to the price sensitivities are identified in order to provide a point of reference for considering the results presented. The detailed results for each of the price cases are available in Appendix IV.

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[6] The document can be found at www.energy.gov.ab.ca

[7] The expected monetary value (EMV) is the overall probability weighted net present value (NPV). NPV is discounted project net cash flow (NCF). NCF is net value remaining to the investor after all costs, including payments to governments, have been recovered. The discount rate used to convert NCF to NPV accounts for the return that the investor could earn from alternative investment opportunities. This rate is typically 10% real which is an approximate cost of capital. It is noted that some commentators utilize higher discount rates such as 15% or even 20%; such, however, are typically applied to the un-risked results with the higher discount rate reflecting the risks. Such application is considered inappropriate as it implicitly assumes higher risk as more information is known. Where reliable probability information is known, such as for Alberta, it more appropriate to follow the practice adopted for this report and assess risks directly through the application of probabilities. The 10% discount rate is reasonable, as reflected in the recent finding by ARC Financial (2006) that the average return on capital for the upstream petroleum in Canada from 2000 to 2005 was roughly 10%.

[8] Profitability Ratio discounted at 10% (PFR_{10}) reflects how effectively the capital is being employed. The ratio in this report is being determined as follows: PFR_{10} = (EMV@10% + Total capital expenditures)/(Total capital expenditures).

[9] Net Operating Revenue is gross sales revenue less transportation costs, investments (including exploration), and operating costs.

3.1 Natural Gas

Table 3.1 summarizes the results for natural gas. The overall results for the province show that the economics of natural gas are very strong across a wide range of prices and conditions. The EMV_{10} results show the provincial average return of $0.73/Mcf after all costs, risks, and a competitive return on investment have been taken into account. For six of the seven PSAC areas representing 78% of production, the EMVs are strongly positive, and the PFR_{10} over 1.3, also suggesting favourable economics. Natural gas rates of return range from 8% - 15% for PSAC 3 to 46% - 55% for PSAC 2.

The notable exception is in PSAC 3 which is shown to have a negative EMV under all price conditions referenced here. PSAC 3 is seen as a mature area for natural gas development. The reserves per well for PSAC 3 are less than half of the next smallest area, PSAC 4. These results are also consistent with the analysis in Technical Report OG#1 that demonstrated the particularly strong linkage between low productivity wells and prices. It is also reflective of the most recent industry trends that see fewer wells being drilled in PSAC 3 in 2006 relative to previous years.

It is pointed out that the average revenue of $7.39/Mcf shown in the table is greater than the price of $6.39/Mcf. This is due to the composition of the natural gas including significant volumes of natural gas liquids that command higher prices.

TABLE 3.1 – NATURAL GAS ECONOMICS (EMV – PRICE $6.39/MCF)

Alberta Gas							
	Modelled Results						
Area	Well EUR Bcf	Average Revenue $/Mcf real	EMV $000 real	EMV $/Mcf real	EMV 10% $000	EMV10% $/Mcf	$PFR_{10\%}$
PSAC 1	6.01	7.52	6231	1.78	2602	0.74	1.47
PSAC 2	1.79	8.33	2798	2.08	1363	1.01	1.55
PSAC 3	0.18	6.30	111	0.69	-17	-0.11	0.95
PSAC 4	0.46	6.25	545	1.50	263	0.72	1.47
PSAC 5	0.67	7.09	747	1.58	325	0.69	1.38
PSAC 6	0.89	6.31	1015	2.03	562	1.12	2.24
PSAC 7	1.04	6.83	1081	1.79	614	1.02	1.84
Total	1.88	7.39	2289	1.68	1039	0.73	1.42

3.2 Conventional Oil Results

Table 3.2 shows the provincial average EMV results for conventional oil to be significantly less attractive than those for natural gas. At $1.74 per barrel (approximately $0.29/Mcf for comparison with natural gas) the oil value is only about one-third of the equivalent value for natural gas.

Similar to the situation with natural gas, notice that the average revenue ($40.38/boe) differs from the price assumed ($50.0/bbl). This reflects the heavy oil quality of the crude being produced. The lower price for heavy oil also helps explain the variation with regards to oil profitability results across the various PSAC regions.

PSAC 2 is generally uneconomic for oil (EMV10%/Boe @ -$4.44). Although it was observed in Technical Report OG#1 that substantial oil reserves exist in PSAC 2, this is reflective of historically large finds in that area. Currently PSAC 2 is predominantly a natural gas area with a few pockets of oil. Table 2.1 showed that more than 85% of the wells being drilled in PSAC 2 are natural gas wells. Table 3.1 supports this observation, showing that natural gas economics are quite attractive in PSAC 2.

The other oil areas of Alberta show very strong economics, with positive discounted EMVs even at the lower price case of $30/bbl. This is shown in Tables A.36 to A.38 in Appendix 4.[10]

TABLE 3.2 – CONVENTIONAL OIL ECONOMICS (EMV – PRICE $51.45/BBL)

Alberta Oil							
	Modelled Results						
Area	Reserves Per Well Mboe	Average Revenue $/boe real	EMV $000 real	EMV $/boe real	EMV 10% $000	EMV 10% $/Boe	$PFR_{10\%}$
PSAC 2	107.09	41.65	-73	-0.90	-361	-4.44	0.78
PSAC 3	86.61	34.51	478	6.21	261	3.39	1.33
PSAC 4	49.35	37.43	166	4.19	29	0.72	1.05
PSAC 5	105.03	44.03	608	8.05	247	3.27	1.23
PSAC 7	134.33	43.83	703	8.40	416	4.98	1.41
Total	99.95	40.38	398.82	5.35	136.35	1.74	1.13

Section IV – Government Share Results

This section shows the government shares associated with the investor economics results provided in tables 3.1 and 3.2. As with the EMV results from the investor perspective, fully risked results are presented for the government shares. Further comparisons for alternative price scenarios are provided in Appendix V.

4.1 Natural Gas Results

Figure 4.1 presents the government shares for natural gas. As can be seen there is some variability in government share across the various areas. The average government share at the EMV price of $6.39/Mcf is 64%. In general the royalties represent the largest portion of this share. The provincial government share includes royalties, bonuses, and provincial corporate income tax.

Excluding the marginal PSAC 3, the individual regions show an undiscounted government share that ranges between 56% and 65% with most values in the low 60% range.

As can be observed from the tables in Appendix V, the government share is negatively related to the price. That is, as prices increase, government share declines. The fact that Alberta's natural

[10] In reviewing the results of the more detailed price cases in Appendix 4 an interesting observation can be made. For some areas (PSAC 2, 3, and 4) the investor economics improve as price declines from $50/bbl to $30/bbl. This somewhat surprising result is related to the price sensitivity of costs. As natural gas drilling represents the overwhelming majority of activity in Alberta, it can be seen that costs are being driven by the improving natural gas economics at higher prices. This is also reflective of the pool sizes for oil being smaller. Further refinement of the oil results would concentrate on pockets within these broad regional areas that may show stronger economics.

gas royalty rates stop increasing after prices above roughly $3.50/Mcf is responsible for this result.

Another important observation is that even considering the higher land bonus bids that have been paid in recent years, bonuses represent a proportionally small component of the overall government share. Some have suggested that bonus bids will appropriately adjust to balance the effects of improved economics.[11] This suggestion is not supported by these results, nor is it consistent with theory[12]. Similarly, the increasing share of bonuses may be indicative of the royalty rate caps above the $3.50/Mcf price level identified above.

Despite the strong investor economics recorded in this analysis it is still premature to conclude that royalty rates should be changed. Before this conclusion can be drawn the analysis requires comparison of the investor economics and government shares for competing jurisdictions. Although some insight on this follows in the next section, this will be the focus of the next Technical report on conventional oil and gas.

TABLE 4.2.4 – NATURAL GAS GOVERNMENT SHARE (PRICE $6.39/MCF)

Alberta Gas								
	Modelled Results							
Area	Well EUR Bcf	Royalty $000 real	Provincial Tax $000 real	Federal Tax $000 real	Bonus $000 real	Provincial Share real %	Federal Share real %	Combined Govt Share real %
PSAC 1	6.01	11,861	1,034	1,980	1,439	53%	11%	65%
PSAC 2	1.79	3,791	462	888	421	50%	12%	62%
PSAC 3	0.18	120	30	57	113	60%	14%	73%
PSAC 4	0.46	564	97	185	102	47%	13%	61%
PSAC 5	0.67	1,046	131	251	217	52%	12%	64%
PSAC 6	0.89	1,222	163	312	141	43%	13%	56%
PSAC 7	1.04	1,563	195	373	261	49%	13%	62%
Total	1.88	3,648	384	736	467	52%	12%	64%

4.2 Conventional Oil Results

Figure 4.2 presents the government shares for conventional oil. As with gas, there is some variability in government share across the various areas. The provincial average share is 70%. Excluding PSAC 2, the individual regions show an undiscounted government share that ranges between 61% and 66%.

The oil results show a mix of regressive and progressive government shares. This can be observed from the results in Appendix 5. In moving from the low price of $30/bbl to a price of $50/bbl the government share increases. This is because the oil royalty rates are sensitive to prices up to nearly $50/bbl. In contrast, the higher price case shows government share declining as the royalty rates are no longer sensitive to increased prices.

[11] An example of this contention is found on page 37 of the "Oil and Gas: Benefits to Alberta and Canada, today and tomorrow, through a fair, stable and competitive fiscal regime" document prepared by the Canadian Association of Petroleum Producers and the Small Explorers and Producers Association of Canada.

[12] There are two reasons to expect that bonus bids would be inefficient at adjust to economic condition changes. First, bonus bids are made based on the expected conditions; unexpected changes clearly are not factored into the expected values. Secondly, even if the changes to conditions were anticipitated, the discount rates applied to future revenues by private investors is typically higher than that applied by government, thereby undervaluing the bids from government's perspective.

As was stated above for natural gas, before any conclusions can be drawn the analysis requires comparison of the investor economics and government shares for competing jurisdictions.

TABLE 4.1.4 – CONVENTIONAL OIL GOVERNMENT SHARE (PRICE $51.45/BBL)

Alberta Oil								
	Modelled Results							
Area	Reserves Per Well Mboe	Royalty $000 real	Provincial Tax $000 real	Federal Tax $000 real	Bonus $000 real	Provincial Share real %	Federal Share real %	Combined Govt Share real %
PSAC 2	107.09	755	68	217	105	90%	19%	109%
PSAC 3	86.61	468	94	223	28	44%	17%	61%
PSAC 4	49.35	214	41	101	26	48%	18%	66%
PSAC 5	105.03	784	122	313	54	46%	17%	63%
PSAC 7	134.33	1,121	133	359	65	48%	17%	66%
Total	99.95	702	95	252	57	52%	18%	70%

Section V – Inter-Jurisdictional Comparisons

This section examines five U.S. states and three Western Canadian provinces. The U.S. states reviewed are: California (CA), Colorado (CO), New Mexico (NM), Texas (TX), and Wyoming (WY). These states represent about two thirds of U.S. onshore Lower 48 oil and gas production[13]. The Western Canadian provinces of Alberta (AB), British Columbia (BC), and Saskatchewan represent about 75 % of oil and 97% of natural gas production in Canada.

Methodology:

Combined government and owner’s share in this report is defined as the combined revenue from land bonus payments, royalties, CIT and other applicable taxes as a share of net operating revenue. Net operating revenue is defined as gross revenue less investment and operating expenditures.

For this comparison three ‘typical’ gas wells and three ‘typical’ oil wells were considered to reflect the range of economic conditions. The gas wells were differentiated based on total reserve size; Gas Well 1 is a shallow well with a 0.2 Bcf, Gas Well 2 is a medium depth well with a 1 Bcf, and Gas Well 3 is deep well containing a 2 Bcf reserve.

The three oil wells were classified by reserve size and oil composition; Oil Well 1 produces heavy crude and contains a 49,300 bbl reserve, Oil Well 2 also produces heavy crude and has a 73,300 bbl reserve, and Oil Well 3 produces light/medium crude and contains a 77,400 bbl reserve.

The specific gas composition and crude oil quality of each of these modelled oil and gas wells is presented in Table 5.1.1.

[13] Alaska is being reviewed as part of the Oil Sands Technical Review Paper series. US Federal Offshore was excluded as well as not being comparable to conventional oil and gas in Alberta with regard to the size of investment nor the economics.

TABLE 5.1.1 – WELL'S PRODUCT CHARACTERISTICS

Gas										Oil	
Well Type	He %	N2 %	CO2 %	H2S %	C1 %	C2 %	C3 %	C4 %	C5+ %	Well Type	API
0.2 Bcf (Well 1)	0.13	3.18	0.2	0.01	95.78	0.48	0.13	0.06	0.03	49,300 bbls (Well 1)	17.7
1 Bcf (Well 2)	0.07	3.86	0.21	0	91.06	2.43	0.99	0.48	0.44	73,300 bbls (Well 2)	22
2 Bcf (Well 3)	0.06	2.27	0.86	0.06	83.91	7.16	3.18	1.34	0.99	77,400 bbls (Well 3)	34.9

When comparing inter-jurisdictional economics it is necessary to account for differences in costs, netback prices, resource characteristics, and fiscal terms. It is worth noting that the Alberta Department of Energy does not maintain a database of information on costs and well performance for the various states analyzed in this report. Research however shows that resources characteristics are comparable. This research suggests that the range of costs and resources in Alberta are consistent with those for the other jurisdictions. As reported in Technical Report OG#1, Alberta is shown to have costs that are comparable to slightly below average in comparison with the rest of Canada and the United States.

IHS/CERA (2007) [14] analyzed the costs for all new natural gas wells in 2005. Canada and the US were divided into 76 basins including conventional and unconventional natural gas. These wells represented about 14 Bcf per day of new or replacement production in Canada and the US in 2005. Figure 5.1 below shows the all-in long-run costs by basin for wells added in 2005. IHS/CERA reports that the average total cost including capital, operating, return on capital, severance tax and royalties for these new wells was $6.83/Mcf with substantial variation between basins. As can be observed, the various Alberta basins identified by IHS/CERA are all below the average cost of $6.83/Mcf. In fact, much of Alberta's resources are shown to be substantially below the average cost. Out of the 76 basins identified, IHS/CERA note that the 20 lowest cost basins represent about 65% of production added from new wells. The study shows the various regions in Alberta to be in these 20 lowest cost basins, with 4 of the 6 Alberta areas identified by IHS/CERA to be in the lowest 7. Additionally, Alberta is several Bcf per day away from the margin in terms of the production that would not be accessed at lower prices. That is, Alberta is far from the highest marginal source of supply for Canada and the US. Given the variation in resources across geologic basins, and associated costs across Canada and the US, this analysis did not adjust the costs to reflect the Alberta cost advantage recorded by HIS/CERA.

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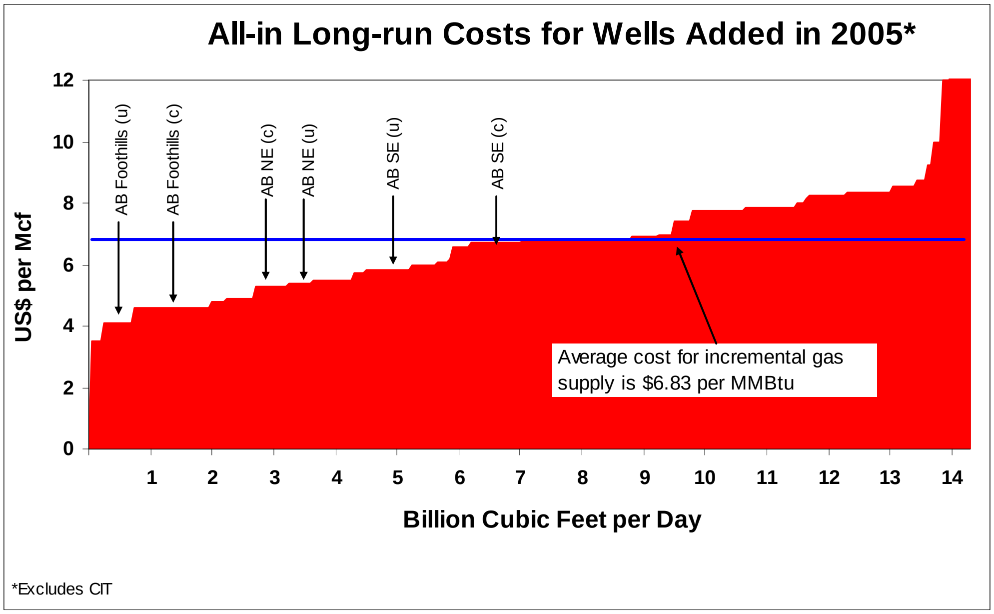
[14] "Diminishing Returns" IHS/CERA, 2007

FIGURE 5.1 – COMPARATIVE COSTS IN CANADA AND THE US



Source: IHS/CERA

Bonus bids, however, were adjusted based on data available to the ADOE.[15] As the value of the bonus bid is determined based on the perceived value of the land, adjustments were made specific to each of the Alberta typical wells as a percentage adjustment based on the average differential. For example, the average bonus in Alberta was CAD$633 per hectare compared to CAD$1194 per hectare for Texas. This implies a bonus bid that is 88.69% higher in Texas relative to Alberta. For the 2 billion cubic feet (Bcf) gas well the assumed Alberta bonus was CAD$434,600 and for Texas it was assumed to be CAD$820,050.

Wellhead prices for both oil and gas were assumed to be different for each jurisdiction/region analyzed. The price adjustment was determined based on the average prices in those jurisdictions relative to Alberta - see Table 5.1.2 below. No adjustments were made based on quality or composition as that is intrinsic to the typical well assumed.

[15] Ken Andrews and Associates (KAA) from Dallas Texas was engaged to provide detail on the US fiscal system. KAA specializes in ad valorem taxes. From the data available to it, KAA provided typical bonus bids for the various states examined. In reviewing these, there is some discrepancy to the values reported at public land auctions. In general, public land auctions tend to show results that are lower than those provided by KAA. One possible explanation of this is that substantial portions of the US are freehold land to which public land auctions are not held. Unlike Alberta that is almost entirely comprised of sedimentary basin that has oil and gas prospectivity, further study could reveal the geographical extent of hydrocarbon occurrences in each of these jurisdictions. That was outside the scope of the current report.

TABLE 5.1.2 – ALBERTA/U.S. PRICE DIFFERENTIALS

	Texas	New Mexico	Colorado	Wyoming	California
Natural Gas	1.13	0.36	0.49	0.13	0.87
Oil (Light/Medium)	1.41	0.85	1.09	1.66	6.64
Oil (Heavy)	0.94	0.37	0.61	1.18	6.17
Note: A positive price differential represents a higher price relative to Alberta					

The fiscal parameters applied to the analysis are presented in Table 5.1.8 with three exceptions. First, the royalty structures for Alberta were used consistent with the previous section. Secondly, for both lower productivity wells (Gas Well 1 and Oil Well 1) the royalty rates for the US jurisdictions were reduced to 12.5%, and additionally to 5% for New Mexico for years in which production averaged less than 3 bbls/day. Finally, adjustments were made to eliminate the severance tax for Colorado for years when production averaged less than 15 bbl/day (90 Mcf/day of natural gas), and for Wyoming the severance tax is reduced to 2% when production averaged less than 10 bbl/day.

Lastly, the analysis for this section is partially risked in that it includes the costs of unsuccessful drilling based on success rates in Alberta. This analysis does not incorporate reserve nor price risk.[16] As these risks are not included, the results tend to show lower government shares than identified in the EMV analysis. The order-of-magnitude of this effect can be seen by comparing the government shares from Table 4.2.4 showing 64% to that of Figure Gas Well 2 showing 58% or from Table 4.1.3 showing 70% to Figure Oil Well 2 showing 51%. This is not significant for the inter-jurisdictional comparisons in this section as here it is the differential that is of interest.

Mineral Right Ownership:

Oil and gas development in Canada and the United States began in the 19th Century. Since that time it has spread throughout most of the individual U.S. states and Canadian provinces. The mineral rights ownership structure varies across Canada and the United States. In some states and provinces the mineral rights are owned primarily by private individuals and corporations (freehold ownership). In others, the public owns almost all of the mineral rights. In most, the mineral rights are held by a combination of federal, state/provincial, First Nations, and freehold owners. Tables 5.1.3 and 5.1.4 show the breakdown of mineral rights ownership for the U.S. and Canada. As can be seen, there is a large difference between Canada and the United States. In Canada, the majority of the mineral rights are managed by the provincial governments, whereas in the U.S. the rights are primarily freehold or federal responsibility.

[16] The decision to exclude these parameters was chosen as the ADOE does not maintain sufficient information to be able to verify these parameters for each of the jurisdictions. As such the fully risked numbers while more comparable to the analysis in Section IV would not be representative of the economics for U.S. jurisdictions.

TABLE 5.1.3 – U.S. OWNERSHIP OF MINERAL RIGHTS

Ownership of Mineral Rights for US States				
	Federal Lands	State Lands	Private Lands	Indian Lands
California	49.9%	2.2%	47.4%	0.5%
Colorado	38.9%	4.4%	55.5%	1.2%
New Mexico	36.2%	11.2%	42.9%	9.7%
Texas	3.7%	0.5%	95.8%	0.0%
Wyoming	49.7%	6.2%	41.0%	3.1%
Average 5 US States	35.7%	4.9%	56.5%	2.9%

Source: National Wilderness Institute, Alberta Energy

TABLE 5.1.4 – CANADIAN OWNERSHIP OF MINERAL RIGHTS

Ownership of Mineral Rights for Canada			
	Provincial Lands	Federal Lands	Private Lands
Alberta	81.0%	10.6%	8.4%
BC	94.0%	1.0%	5.0%
Saskatchewan	75.0%	3.0%	22.0%
Canada	83.3%	4.9%	11.8%

Source: BC Energy and Mines, Saskatchewan Industry and Resources, and Alberta Energy

Resources:
While oil and gas are produced from many of the U.S. states and several of the Canadian provinces, there are a few major producers. Alberta is one of the largest. Other big producers include Texas, and New Mexico. Table 5.1.5 shows the annual production of oil and natural gas for each of the jurisdictions considered. These jurisdictions represent the bulk of production for Canada and onshore U.S. excluding Alaska. Alberta is the largest gas producer and the third largest conventional oil producer.

TABLE 5.1.5 – COMPARISON OF PRODUCTION

Production (2005)				
	Oil[1] MMbls	Share of National[2]	Gas (Bcf)	Share of National[2]
US				
California	230.3	21.3%	304	2.1%
Colorado	22.8	2.1%	1,098	7.6%
New Mexico	60.7	5.6%	1,544	10.7%
Texas	387.7	35.9%	4,899	34.1%
Wyoming	51.6	4.8%	1,572	10.9%
Combined 5 US States	753.1	69.7%	9,417	65.5%
Canada				
Alberta	208.6	42.1%	5,022	78.2%
BC	10.7	2.2%	988	15.4%
Saskatchewan	153.0	30.9%	247	3.8%
Combined Western Canada	372.3	75.1%	6,257	97.4%

[1]Excludes production from oil sands and natural gas liquids

[2]For the US, National refers to Lower 48 excluding Federal Offshore

Source: U.S. Energy Information Administration, CAPP, AEUB and Alberta Energy

Table 5.1.6 shows the reserves remaining for these 8 jurisdictions. As can be seen the production and reserves are related, jurisdictions that have higher production also have higher reserves.

Notice that Alberta's remaining conventional oil reserves are larger than all but California and Texas, and gas reserves are larger than all but Texas.

TABLE 5.1.6 – COMPARISON OF RESERVES

	Reserves (2005)			
	Oil[1] (Billion bls)	Share of National[2]	Gas (Tcf)	Share of National[2]
US				
California	3.4	26.2%	3	1.8%
Colorado	0.3	1.9%	17	9.3%
New Mexico	0.7	5.3%	18	10.2%
Texas	4.9	37.5%	57	31.7%
Wyoming	0.7	5.4%	24	13.3%
Combined 5 US States	10.0	76.3%	118	66.3%
Alberta	1.6	36.8%	40	71.1%
BC	0.1	2.3%	12	21.8%
Saskatchewan	1.2	27.6%	3	5.8%
Combined Western Canada	2.9	66.7%	56	98.7%

[1]Excludes oil sands and natural gas liquids
[2]For the US, National refers to Lower 48 excluding Federal Offshore
Source: U.S. Energy Information Administration, CAPP, AEUB and Alberta Energy

The number of wells operating in these jurisdictions is presented in Table 5.1.7. Alberta's total number of natural gas wells is larger than that of any other jurisdiction listed; however, the total number of oil wells in Alberta is third out of the 8 jurisdictions listed.

TABLE 5.1.7 – COMPARISON OF OPERATING WELLS

	Number of Operating Wells (2005)			
	Oil Wells[1]	Share of National[2]	Gas Wells	Share of National[2]
US				
California	45,367	9.1%	1,356	0.3%
Colorado	7,567	1.5%	22,691	5.4%
New Mexico	23,611	4.7%	40,157	9.5%
Texas	144,424	28.8%	74,827	17.7%
Wyoming	10,205	2.0%	23,734	5.6%
Combined 5 US States	231,174	46.1%	162,765	38.5%
Alberta	31,611	56.6%	95,513	80.5%
BC	1,089	1.9%	5,217	4.4%
Saskatchewan	23,156	41.5%	17,876	15.1%
Combined Western Canada	55,856	100.0%	118,606	100.0%

[1]Excludes oil sands wells
[2]For the US, National refers to Lower 48 excluding Federal Offshore. For Canada, National refers to Western Canada
Source: U.S. Energy Information Administration, CAPP, and Alberta Energy

Fiscal Systems:
Given the varying mineral rights ownership structures and resource characteristics, it is to be expected that the fiscal systems in the various jurisdictions would be different. As freehold ownership rights are widespread in many U.S. states, U.S. states have typically chosen to apply severance taxes and ad valorem property taxes in addition to any imposed royalty. Severance tax is generally applied to gross production net of the royalty charged by the owner of the mineral rights. Unlike Alberta's freehold mineral tax that applies only to the production from mineral rights in Alberta that are not managed by the Crown, the severance tax in the U.S. jurisdictions is applied to all production. Similarly, a number of ad valorem taxes including property and school

taxes are typically imposed on the value of the oil and gas resources in the United States. In Alberta property taxes are imposed based on the value of land improvements.

Corporate income tax (CIT) represents another difference. In Canada, the provincial CIT is imposed on top of the federal CIT, whereas in the U.S., CIT paid to the states are deductible from income for determining U.S. federal CIT. In some states, the federal CIT is also a deduction from taxable income for determining state CIT.

The royalty and CIT structures for Alberta were described in the Information Briefing series (reports 1 -7). Where Alberta (and BC and Saskatchewan) applies a royalty formula that is sensitive to both price and production, typically the rates in U.S. jurisdictions are fixed. However, royalty rates in the U.S. (as with freehold in Alberta) vary from property to property depending on the expected profitability of the property. In general, the lowest royalty rate being applied in the U.S. is 12.5%; this is frequently used for state and federal lands. On the upper end of the range, royalty rates are typically not much higher than 25%, although royalty rates of up to 40% have been identified for hot land prospects when competition for certain mineral rights has been strong. An example of these high rates exists in the Barnett Shale play in Texas[17].

Table 5.1.8 summarizes the various taxes and royalties in the jurisdictions examined in this report. Comparing the various combinations of royalties, severance taxes, ad valorem taxes and CIT can be quite a challenge as the base for the various taxes and royalties is not the same. The most effective method of comparing the various fiscal systems is to look at the total share of the revenue going to governments and owner's after investment and operating costs are considered. These comparisons are presented below. Another way to make such comparisons is to examine the impact of the various fiscal tools on incremental earnings. This impact is referred to as the marginal take. As can be seen in Table 5.1.8, Alberta has the lowest marginal take of any of the jurisdictions examined.

Government Share Comparison Results

BC and Saskatchewan were not directly compared to Alberta in this analysis. BC tends to be largely a natural gas producing region, whereas Saskatchewan has a combination of heavy oil and shallow natural gas. Table 5.1.8 provided a comparison of the various fiscal tools employed in BC and Saskatchewan relative to Alberta. Similar to Alberta, a number of royalty adjustments apply to each of these jurisdictions as well. For a more detailed explanation of the different provinces, readers are encouraged to refer to the Oil and Gas Fiscal Regimes of the Western Canadian Provinces.

In general, both BC and Saskatchewan apply a higher government take based on comparable royalty rates and higher CIT rates. The reason that the royalty rates are comparable is that the resources in BC tend to be similar to the higher productivity resources in western Alberta (PSAC areas 1, 2, and 7), whereas in Saskatchewan the resources are more similar to the resources in eastern Alberta (PSAC areas 3 and 4).

[17] "Fiscal Terms Report for Alberta Energy", prepared by Wood Mackenzie, May 2, 2006 page 1.

TABLE 5.1.8 – COMPARISON OF FISCAL PARAMETERS

Comparison of USA and Alberta Fiscal Parameters[1]

	Corporate Income Tax[2]			Royalty[8]	Severance Tax		Ad Valorem Tax[11]	Combined Marginal Take	
	Federal[3,4,5,6]	State[4,7]	Combined		Oil	Gas		Oil	Gas
CALIFORNIA	31.85%	8.84%	37.87%	22.5%	C$0.07/bbl (US$0.06)	C$0.07/10 Mcf (US$0.06)	1.05%	52.16%	52.16%
COLORADO	31.85%	4.63%	35.01%	20.0%	2-5% of Net Revenue[10] less 87.5% of Ad Valorem Tax		6.356%	50.84%	50.84%
NEW MEXICO	31.85%	7.60%	37.03%	20.0%	8.66%		2.2980%	54.16%	54.16%
TEXAS	31.85%	1.00%	32.53%	25.0%	4.6% + C$0.0027/bbl (US$0.0022)	7.50%	2.20%	54.10%	55.50%
WYOMING	31.85%	0.00%	31.85%	20.0%	6.00%		6.51%	51.02%	51.02%
States' Average		4.41%	34.86%	21.5%				52.46%	52.74%
BC	20.00%	12.00%	32.00%	Gas:[9] 23.85% Oil:[9] 16.82%	None		None	43.44%	48.22%
Sask	20.00%	12.00%	32.00%	Gas: 12.80% Oil: 17.60%	None		None	43.97%	40.70%
Alberta	**20.00%**	**10.0%**	**30.00%**	**Gas: 20.45%** **Oil: 14.78%**	**None**		**None**	**40.35%**	**44.32%**

Notes:

1. All dollar values are in Canadian $; 2005 FX = 1.2084 C$/US$

2. Federal and Provincial tax rates are additive in Canada. In the USA State tax is a deduction in determining the base for Federal tax

3. US federal corporate income tax (CIT) based on a 35% CIT assumption. (Actual rate is sliding:0-50K 15%, 50-75K 25%, 75-100K 34%, 100-335K 39%, 335-10000K 34%, 10000-15000 35%, 15000K-18333.333K 38%, 18333.333K+ 35%.)

4. The assumed US federal CIT rate of 31.85% includes a 9% US domestic production tax deduction due to be completely phased in for 2010.

5. 2005-2006 the deduction will be 3%, 2007-2009 the deduction will be 6%, 2010 onward the deduction will be 9% (this reduces federal tax rate to 31.85%)

6. Canada's CIT is expected to be reduced to 19% by January 1, 2010

7. Saskatchewan - Reduced to 14% on July 1, 2006, 13% on July 1, 2007, 12% on July 1, 2008

8. Royalty rates in the USA are a fixed percentage whereas in Alberta the rate is sensitive by formula to well productivity and price.

9. B.C. royalties are 2005 (Jan to Sept)

10. Net Revenue = Gross Revenue - Royalties

11. Ad valorem tax is based on the assessed value of property

Note: Reserves and production are for conventional sources only, oil sands reserves and production are not included.

Before presenting the results of the government shares comparison from this analysis it is noted that two reports were commissioned by the Alberta Department of Energy in 2006 to compare the fiscal systems in Alberta and Texas. The first is a report by Chen and Mintz of the CD Howe institute and the University of Toronto that compares the effective rate of tax (including royalties) between Alberta and Texas. The study's authors define the effective tax rate as[18]:

> *The marginal effective tax rate is a summary measure of the extent to which taxes impinge on investment decisions. It is measured by calculating the amount of tax paid as a percentage of the pre-tax return on capital that would be required to cover the taxes and the financing of capital with debt and equity. For example, if a business invests in capital that yields a pre-tax rate of return on capital equal to 10 percent and, after taxes, a rate of return on capital equal to 6 percent, the marginal effective tax rate would be calculated as 40 percent (10 minus 6 percent divided by 10 percent).*

18 "Is the Alberta Fiscal Regime for Oil and Gas Competitive?", Duanjie Chen and Jack Mintz, April, 2006, page 3.

Chen and Mintz find that the effective tax rates in Alberta are substantively lower than those in Texas[19]:

> *"Treating royalties as part of the fiscal system in Alberta and Texas (even though land is privately owned), effective tax rates on capital, including both corporate taxes and royalties, are much lower in Alberta (33 percent) compared to Texas (47 percent)."*

The other report commissioned by the Alberta Department of Energy was completed by Wood Mackenzie. In that report, Wood Mackenzie was asked to review the assumptions being made by the ADOE and comment on the government share in Alberta versus U.S. jurisdictions. In general, Wood Mackenzie finds that the combined government and resource owner's share in Texas is higher than that in Alberta. Wood Mackenzie suggests that the actual variance in effective government share is 12 percentage points higher in Texas compared to Alberta. In addition to Texas, Wood Mackenzie reported combined government and owner's share for 5 other jurisdictions: Louisiana, New Mexico, Oklahoma, Colorado and Wyoming. Compared to Alberta, these jurisdictions had shares that ranged from 5 percentage points higher (Wyoming) to 12 percentage points higher (Louisiana).

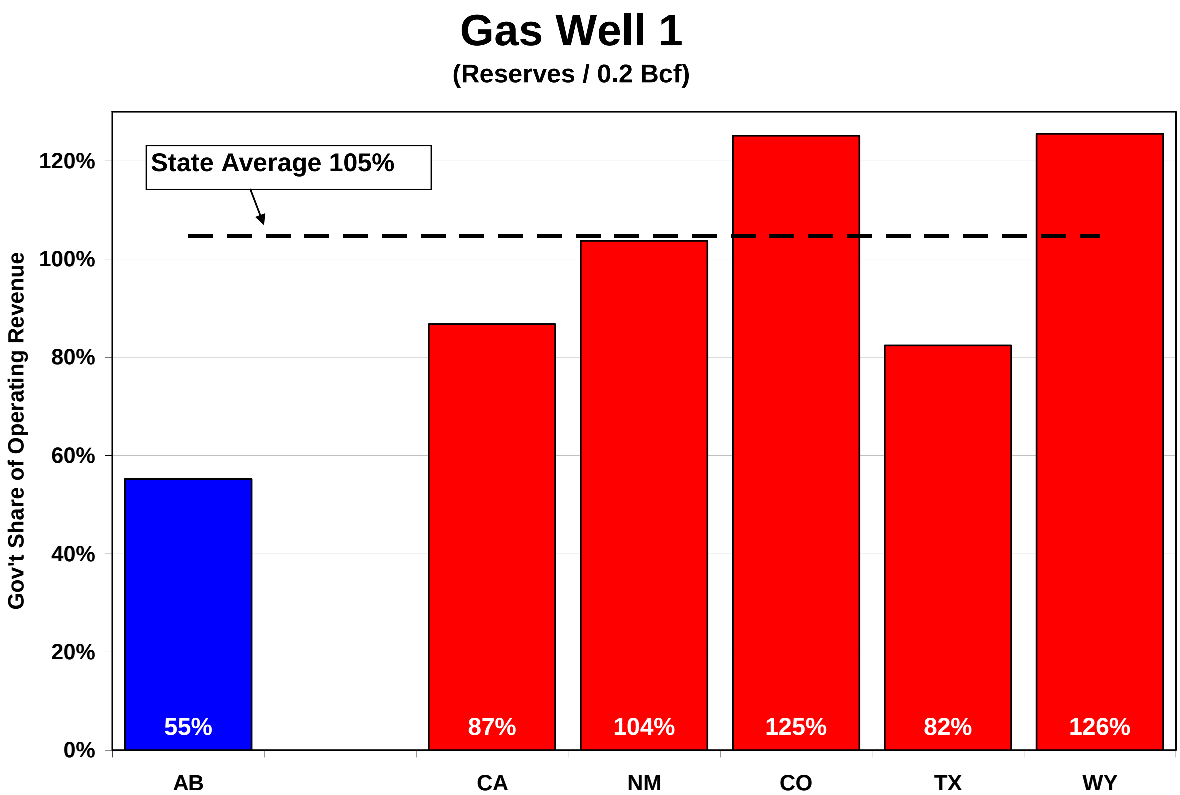
Figures 5.2 to 5.4 show the government/resource owner's share for each U.S. jurisdiction compared to that for Alberta for the three representative gas wells. Figures 5.5 to 5.7 show the same information for the representative oil wells. Representing a wide range of well characteristics, these results show the government share from natural gas developments in Alberta to be 5 to 12 percentage points below that for the U.S. jurisdictions. The distribution of the government/resource owner's share among the various fiscal components is shown in the associated tables.

The results for Gas Well 1 show a much larger differential, illustrating one of the advantages of Alberta's system where royalty rates automatically adjust downward for low productivity wells. In contrast, the U.S. States that rely on significant severance taxes and ad valorem taxes do not automatically adjust.

The oil comparison results show a much wider differential, as the U.S. government/resource owner's incremental share ranges from 22 to 27 percentage points higher than that for Alberta. The significantly higher U.S. shares shown for oil relative to natural gas reflect lower net operating revenue based on relatively lower reserves per well.

[19] Ibid., page 4.

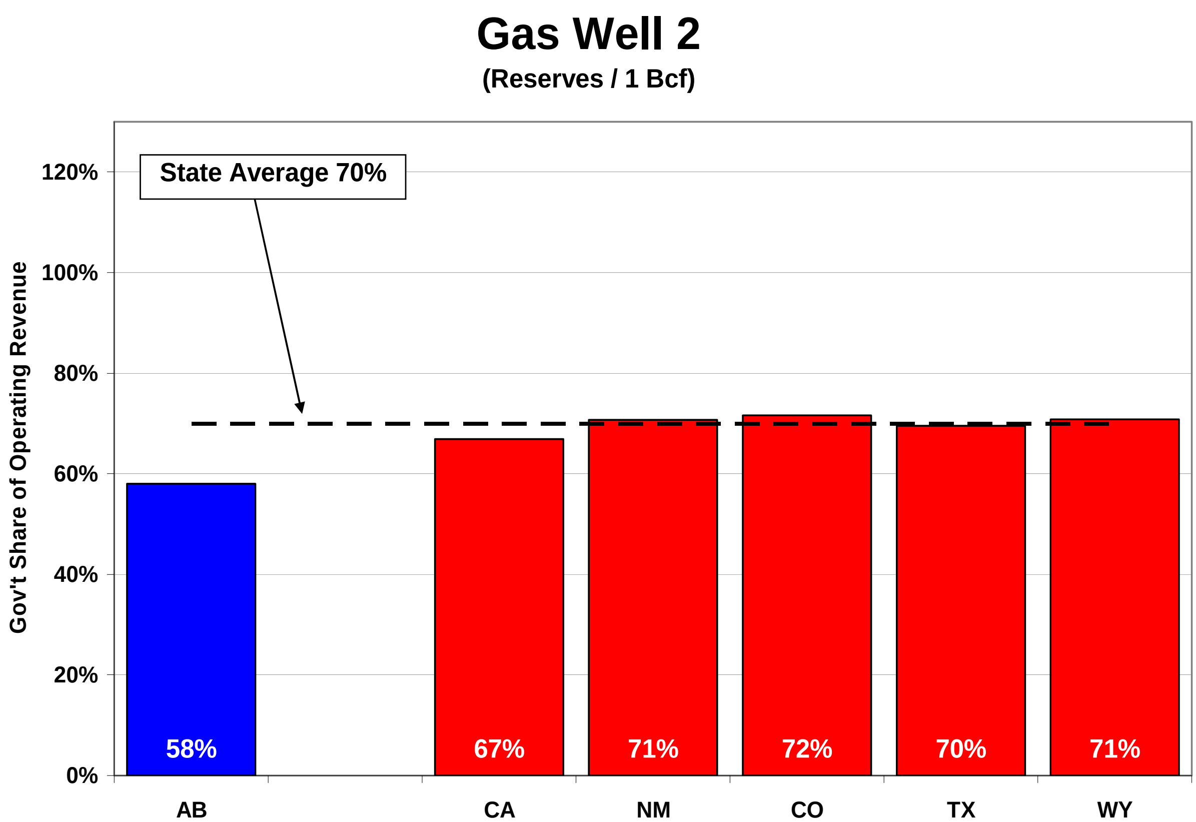
FIGURE 5.2 – GAS WELL 1



Gas Well 1 Government Share Components
(Net Operating Revenue)

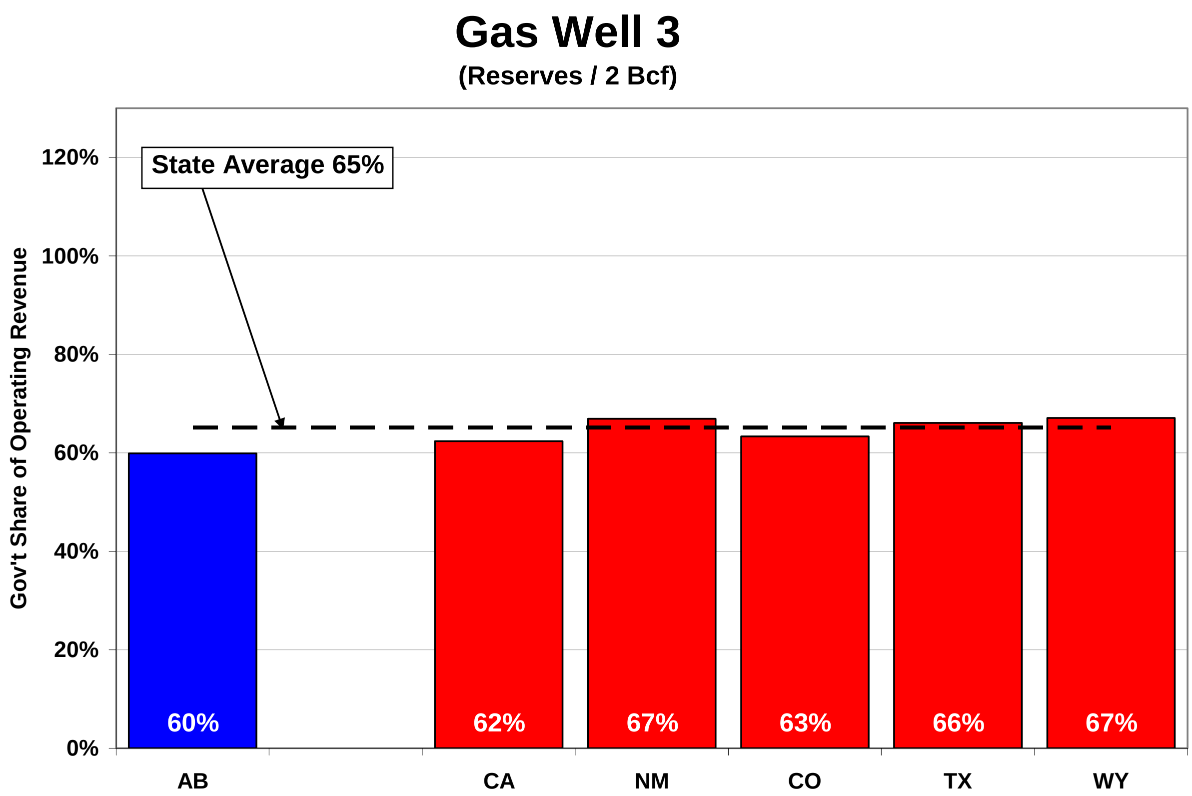
Jurisdiction	CIT	Royalty	Excise Tax	Ad Valorem	Total Gov't Take
Texas	17.74%	40.30%	21.16%	3.20%	82.40%
New Mexico	14.15%	53.40%	32.37%	3.81%	103.72%
Colorado	23.26%	73.86%	2.48%	25.54%	125.14%
Wyoming	11.96%	70.03%	29.42%	14.10%	125.51%
California	26.80%	57.44%	0.40%	2.13%	86.77%
Alberta	27.33%	27.90%	0.00%	0.00%	55.23%

FIGURE 5.3 – GAS WELL 2



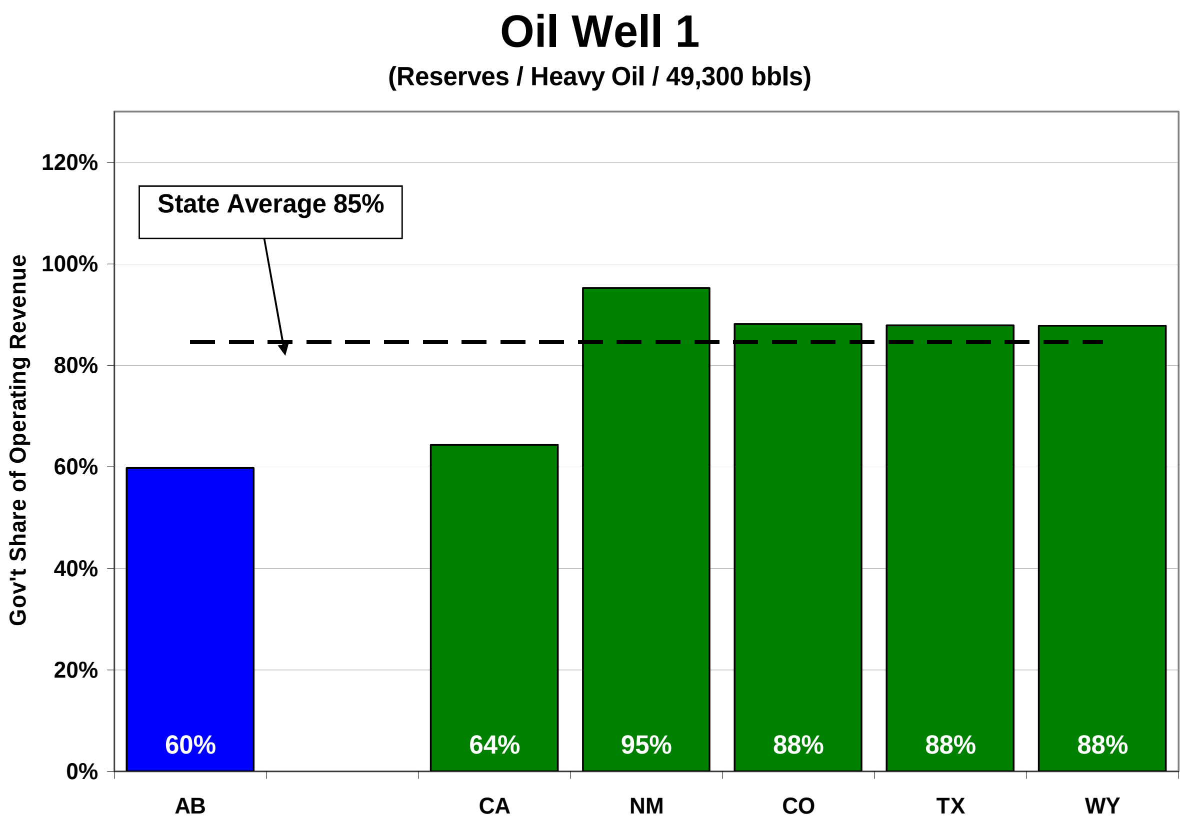
Gas Well 2 Government Share Components (Net Operating Revenue)					
Jurisdiction	CIT	Royalty	Excise Tax	Ad Valorem	Total Gov't Take
Texas	19.79%	39.30%	8.84%	1.58%	69.52%
New Mexico	24.15%	33.39%	11.57%	1.59%	70.69%
Colorado	27.25%	35.47%	0.65%	8.47%	71.83%
Wyoming	21.99%	35.19%	8.45%	5.13%	70.76%
California	27.87%	38.08%	0.13%	0.81%	66.89%
Alberta	22.22%	34.67%	0.00%	0.00%	56.89%

FIGURE 5.4 – GAS WELL 3



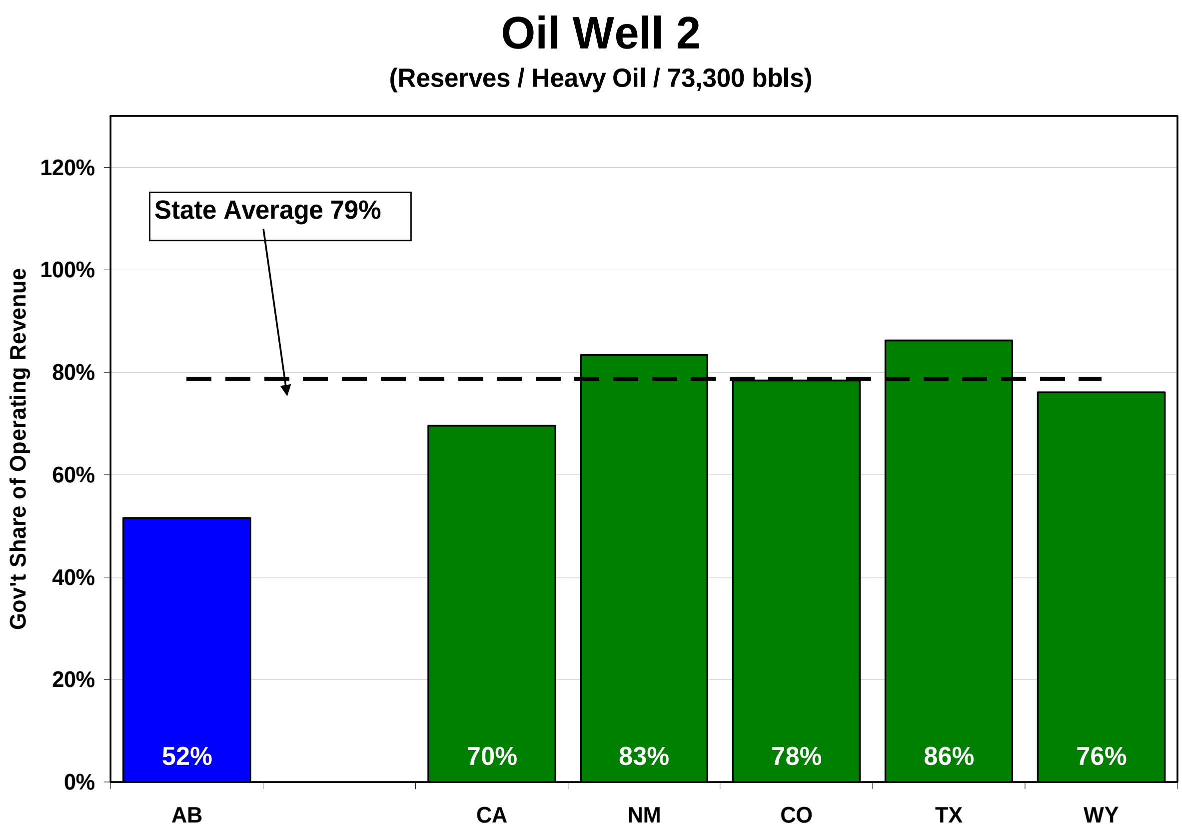
Gas Well 3 Government Share Components (Net Operating Revenue)					
Jurisdiction	CIT	Royalty	Excise Tax	Ad Valorem	Total Gov't Take
Texas	19.64%	36.55%	8.22%	1.66%	66.08%
New Mexico	23.87%	30.73%	10.64%	1.66%	66.90%
Colorado	25.99%	31.28%	0.44%	5.63%	63.34%
Wyoming	21.55%	31.89%	7.65%	6.00%	67.09%
California	27.08%	34.36%	0.09%	0.84%	62.38%
Alberta	19.96%	39.93%	0.00%	0.00%	59.89%

FIGURE 5.5 – OIL WELL 1



Oil Well 1 Government Share Components (Net Operating Revenue)					
Jurisdiction	CIT	Royalty	Excise Tax	Ad Valorem	Total Gov't Take
Texas	15.21%	50.87%	19.48%	2.37%	87.93%
New Mexico	13.65%	49.68%	30.12%	1.80%	95.25%
Colorado	22.83%	51.18%	2.01%	12.15%	88.17%
Wyoming	16.26%	47.51%	17.87%	6.20%	87.84%
California	27.83%	35.39%	0.15%	0.95%	64.32%
Alberta	27.00%	32.74%	0.00%	0.00%	59.74%

FIGURE 5.6 – OIL WELL 2

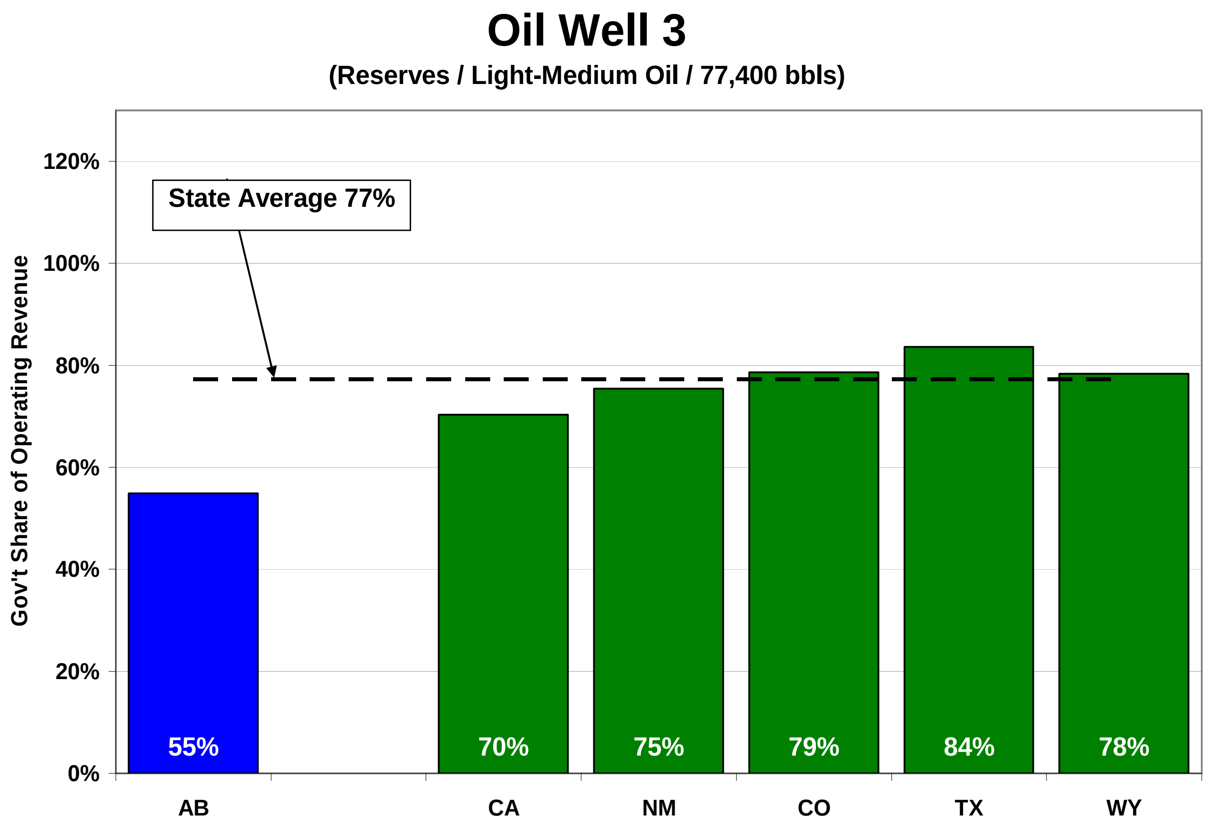


Oil Well 2 Government Share Components

(Net Operating Revenue)

Jurisdiction	CIT	Royalty	Excise Tax	Ad Valorem	Total Gov't Take
Texas	10.38%	62.22%	12.40%	1.20%	86.20%
New Mexico	13.14%	51.26%	17.76%	1.20%	83.36%
Colorado	18.03%	52.20%	2.53%	5.62%	78.38%
Wyoming	14.09%	50.32%	11.22%	0.39%	76.02%
California	21.07%	48.07%	0.33%	0.12%	69.59%
Alberta	21.12%	30.41%	0.00%	0.00%	51.53%

FIGURE 5.7 – OIL WELL 3



Oil Well 3 Government Share Components (Net Operating Revenue)					
Jurisdiction	**CIT**	**Royalty**	**Excise Tax**	**Ad Valorem**	**Total Gov't Take**
Texas	14.63%	56.06%	11.25%	1.66%	83.60%
New Mexico	20.39%	39.58%	13.83%	1.60%	75.39%
Colorado	22.55%	46.19%	1.85%	8.05%	78.64%
Wyoming	18.24%	45.03%	9.75%	5.33%	78.35%
California	23.82%	45.50%	0.24%	0.82%	70.37%
Alberta	24.43%	30.48%	0.00%	0.00%	54.91%

Section VI – Findings and Observations

- Investor exploration economics in the natural gas sector are attractive for all scenarios.
- The expected monetary value calculation for the Alberta natural gas industry shows a weighted average government share of 64%.
- For natural gas, the provincial average government share at a price of $6.75 is set at 64% of the net operating revenue once risk is accounted for. This share increases to 66% if price falls to $3.50/Mcf and decreases to 62% at prices of $9.00/Mcf. This shows the regressive nature of the government share in Alberta, reflecting a negative relationship with prices due to the fact that the natural gas royalty structure is not sensitive to prices higher than roughly $3.50/Mcf.
- For the conventional oil sector investor exploration economics are also positive; however, they are not as attractive as those for natural gas. This is to be expected, reflecting the relative maturity of oil developments in Alberta.
- The government share for the Alberta conventional oil industry is shown as 70%. The government share for conventional oil in Alberta has a positive relationship with price up to about $50/bbl. The share increases from 65% at $30/bbl to 76% at $50/bbl. For prices above $50/bbl however, the share decreases to 68%. This is reflective of the fact that the oil royalty curves are price sensitive up to roughly $50/bbl.
- Another important observation relates to bonus bids. Even considering the higher land bonus bids that have been paid in recent years, bonuses represent a proportionally small component of the overall government share. The suggestion that bonus bids will appropriately adjust to balance the effects of improved economics is not supported by these results.
- Comparisons with U.S. jurisdictions show that Alberta's government/owner share is significantly below that of the United States. For natural gas, the shares range from 5 to 12 percentage points lower in Alberta. For conventional oil, the shares for Alberta are 22 to 27 percentage points lower than those for the U.S. jurisdictions studied.

Appendix I: Production Assumptions

The selection of typical wells involved the review of all wells drilled for oil and gas in Alberta over a number of recent years to create success rates, well production profiles, and a number of other parameters reflecting the resource quality (e.g., oil and gas composition, recovery factors, loss factors, etc…). The province (as shown in figure 5.1) was divided into seven regions to reflect the varying resource and cost conditions that exist. These seven regions were first introduced by the Petroleum Services Association of Canada (PSAC).

Figure A.I.1 – ALBERTA PSAC AREAS

Statistical analysis was used to create three wells for each commodity in each PSAC area as appropriate. The three wells are: the P10 or large well (only 10 percent of the wells are larger than this well), the P50 or medium well (the median where 50 percent of the wells are larger than this well and 50 percent are smaller), and the P90 or small well (where 90 percent of the wells are larger than this well). The use of the P90, P50, and P10 allows for the creation of the Swanson's mean which is an alternative to the arithmetic mean and the median as an indication of central tendency. The Swanson's Mean is an effective tool for analyzing distribution that are skewed such as oil and gas wells. There are a lot of small wells and a few very large wells. This implies that the arithmetic mean will be too large as a few very large wells will skew the results. Similarly, the median is not very appropriate as it does not sufficiently reflect the positive impact of the larger wells on the economics. The result is a need to apply some truncation of the results, and this is something that the Swanson's Mean accomplishes.

Provincial results are calculated as the weighted average based on activity and expected ultimate recovery per well. Table A.1 shows the weights used to calculate Provincial averages.

TABLE A.I.1 –EXPECTED ULTIMATE RECOVERY (EUR) (WEIGHTED BASED ON DRILLING AND ACTIVITY)

Weight Based on Drill and EUR - Conventional Oil							
PSAC 1	PSAC 2	PSAC 3	PSAC 4	PSAC 5	PSAC 6	PSAC 7	Total
0%	20%	22%	15%	19%	0%	24%	100%

Weight Based on Drill and EUR - Natural Gas							
PSAC 1	PSAC 2	PSAC 3	PSAC 4	PSAC 5	PSAC 6	PSAC 7	Total
16%	36%	16%	4%	15%	3%	11%	100%

Well Profile

Well production profiles were developed based on wells drilled between 1998 to 2002. These dates were chosen to ensure adequate production history existed to facilitate reserve estimations based on extrapolation from decline analysis. Full production history for these wells was used up to the most recent year where available.[20] The production profiles were developed by taking the average production profiles for wells within 5 percentile points above and below the wells being developed. For example the production profile for the P10 well was developed using the average well production profiles for the P5 to P15 wells. If this resulted in a reserve estimate that differed from the P10 well then each year was scaled to obtain the reserve estimates for the P10 well.

Gas Wells

Gas well production profiles are summarized in the tables below. Notice that production profile for the low price case is larger than the base case and the high case profiles. This is because of the adjustments that were made on the pool sizes. These adjustments consisted in eliminating wells that did not generate sufficient revenues to cover operating expenses (not half cycle economic).[21] This was done with the rationale that once prices drop, producers would decrease the level of activity and hence small pools are not developed for not being economically attractive and hence producers would consider these pools as dry holes. These adjustments produce a new series of P10, P50, and P90 pools. These pools are larger than those of the base and high case and therefore Swanson wells are also larger. Tables A.2 to A.8 show the gas production profiles from each of the areas. Table A.9 displays the assumptions used for the gas compositions and Table A.10 provides the liquid recovery efficiencies assumed in the analysis.

[20] While it can be shown that there is evidence of declining well productivities it can also be shown that this is directly influenced by price as demonstrated in Technical Briefing #1.

[21] Some screening was required due to the use of actual wells. As monthly natural gas prices in Alberta have fluctuated from a low of $1.65/Mcf to a high of $11.82/Mcf, clearly some low productivity wells would generate sufficient revenues at the upper end of this range to cover operating expenditures while not having sufficient revenues to cover these costs at the lower end of the range. These wells would produce when prices were high and be shut-in when prices were low. The data confirms this.

TABLE A.I.2 – PSAC 1 Typical Wells
PRODUCTION PROFILE (RAW NATURAL GAS - MMCFE)

	$6.75			$3.50			$9.00		
Year	**Large** Gas Volume mmcf	**Medium** Gas Volume mmcf	**Small** Gas Volume mmcf	**Large** Gas Volume mmcf	**Medium** Gas Volume mmcf	**Small** Gas Volume mmcf	**Large** Gas Volume mmcf	**Medium** Gas Volume mmcf	**Small** Gas Volume mmcf
2006	2,568	694	216	2,648	723	267	2,568	694	216
2007	2,515	935	176	2,593	976	217	2,515	935	176
2008	2,186	718	125	2,254	749	155	2,186	718	125
2009	1,742	562	80	1,796	587	99	1,742	562	80
2010	1,359	461	52	1,401	481	64	1,359	461	52
2011	1,062	324	55	1,095	338	67	1,062	324	55
2012	888	251	34	916	263	42	888	251	34
2013	759	173	20	783	180	24	759	173	20
2014	619	136	11	638	143	14	619	136	11
2015	504	99	1	520	103	1	504	99	1
2016	414	68		427	71	0	414	68	
2017	344	52		355	55	0	344	52	
2018	284	25		293	25	0	284	25	
2019	230	16		237	15	0	230	16	
2020	194	12		200	12	0	194	12	
2021	154	11		159	11	0	154	11	
2022	129	8		133	9	0	129	8	
2023	104	5		107	6	0	104	5	
2024	78	5		80	6	0	78	5	
2025	56	4		57	4	0	56	4	
2026	43	4		44	4	0	43	4	
2027	28	3		29	3	0	28	3	
2028	24	2		26	2	0	24	2	
2029	21	1		22	2	0	21	4	
2030	16			17		0	16		
2031	9			9		0	9		
2032	8			8		0	8		
2033	7			7		0	7		
2034	4			1		0	4		
2035	2					0	2		
2036						0			
2037						0			
2038						0			
2039						0			
2040						0			
2041						0			
2042						0			
2043						0			
2044									
Total	**16,350**	**4,570**	**770**	**16,855**	**4,768**	**952**	**16,350**	**4,573**	**770**

TABLE A.I.3 – PSAC 2 Typical Wells
PRODUCTION PROFILE (RAW NATURAL GAS - MMCFE)

	$6.75			$3.50			$9.00		
Year	**Large** Gas Volume mmcf	**Medium** Gas Volume mmcf	**Small** Gas Volume mmcf	**Large** Gas Volume mmcf	**Medium** Gas Volume mmcf	**Small** Gas Volume mmcf	**Large** Gas Volume mmcf	**Medium** Gas Volume mmcf	**Small** Gas Volume mmcf
2006	1,216	285	56	1,277	325	83	1,215	284	55
2007	820	195	41	862	222	60	820	194	40
2008	615	155	33	646	178	49	614	155	33
2009	472	129	22	496	148	33	472	129	22
2010	380	103	14	399	117	19	380	102	13
2011	305	72	9	321	83	13	306	72	8
2012	254	47	5	267	53	7	255	47	5
2013	207	29	1	217	33	2	207	28	1
2014	169	17		176	20		168	18	
2015	134	11		140	13		134	11	
2016	108	7		113	8		107	6	
2017	86	5		91	5		86	4	
2018	72	3		75	3		70	3	
2019	56	2		58	2		55	1	
2020	44	2		46	2		45	1	
2021	37	1		39	1		38		
2022	29			31			30		
2023	24			25			24		
2024	21			21			21		
2025	16			16			16		
2026	12			12			12		
2027	10			10			10		
2028	8			8			8		
2029	7			7			6		
2030	5			6			5		
2031	4			4			4		
2032	4			4			3		
2033	2			2			2		
2034	1			1			1		
2035									
2036									
2037									
2038									
2039									
2040									
2041									
2042									
2043									
2044									
Total	**5,118**	**1,063**	**181**	**5,368**	**1,212**	**266**	**5,113**	**1,056**	**177**

TABLE A.I.4 – PSAC 3 Typical Wells
PRODUCTION PROFILE (RAW NATURAL GAS - MMCFE)

	$6.75			$3.50			$9.00		
Year	**Large** Gas Volume mmcf	**Medium** Gas Volume mmcf	**Small** Gas Volume mmcf	**Large** Gas Volume mmcf	**Medium** Gas Volume mmcf	**Small** Gas Volume mmcf	**Large** Gas Volume mmcf	**Medium** Gas Volume mmcf	**Small** Gas Volume mmcf
2006	87	26	7	106	34	18	85	26	8
2007	61	20	6	76	26	14	61	20	6
2008	47	17	6	59	22	13	48	17	5
2009	39	14	4	49	18	8	39	14	4
2010	33	12	3	40	15	5	32	12	2
2011	26	9	2	32	12	4	27	9	1
2012	21	8	5	26	9	9	22	7	3
2013	17	6	5	21	7	10	18	6	4
2014	14	5	3	18	6	6	14	5	3
2015	12	4		15	5		12	3	
2016	11	3		12	5		10	3	
2017	9	1		11	3		8	2	
2018	8	1		9	2		7	1	
2019	6	1		7	2		6	1	
2020	5	1		6	2		5	1	
2021	5	1		5	1		5	1	
2022	5			5			4		
2023	4			4			3		
2024	4			4			3		
2025	4			4			3		
2026	2			3			2		
2027	1			2			1		
2028	1			2			1		
2029	1			2			1		
2030	1			2			1		
2031	1			2			1		
2032	1			2			1		
2033	1			2					
2034	1			1					
2035									
2036									
2037									
2038									
2039									
2040									
2041									
2042									
2043									
2044									
Total	**427**	**130**	**40**	**526**	**170**	**87**	**422**	**127**	**34**

TABLE A.I.5 – PSAC 4 Typical Wells
PRODUCTION PROFILE (RAW NATURAL GAS - MMCFE)

	$6.75			$3.50			$9.00		
Year	**Large** Gas Volume mmcf	**Medium** Gas Volume mmcf	**Small** Gas Volume mmcf	**Large** Gas Volume mmcf	**Medium** Gas Volume mmcf	**Small** Gas Volume mmcf	**Large** Gas Volume mmcf	**Medium** Gas Volume mmcf	**Small** Gas Volume mmcf
2006	256	63	19	290	90	46	256	59	15
2007	195	52	14	220	74	37	195	49	13
2008	160	42	7	181	60	20	160	40	7
2009	123	29	1	138	42	3	122	28	1
2010	98	20		110	29		97	19	
2011	76	12		85	16		75	11	
2012	58	8		66	10		58	6	
2013	46	3		52	5		45	3	
2014	37	2		41	5		37	2	
2015	29	1		33	2		29	1	
2016	23			26			23		
2017	19			21			18		
2018	15			16			15		
2019	11			13			11		
2020	9			8			9		
2021	8			6			7		
2022	6			5			6		
2023	4			5			4		
2024	4			4			4		
2025	3			2			3		
2026	2			2			2		
2027	2			2			2		
2028	2						2		
2029	2						2		
2030	2						2		
2031	2						2		
2032									
2033									
2034									
2035									
2036									
2037									
2038									
2039									
2040									
2041									
2042									
2043									
2044									
Total	**1,193**	**231**	**40**	**1,327**	**332**	**106**	**1,189**	**218**	**36**

TABLE A.I.6 – PSAC 5 Typical Wells
PRODUCTION PROFILE (RAW NATURAL GAS - MMCFE)

	$6.75			$3.50			$9.00		
Year	**Large** Gas Volume mmcf	**Medium** Gas Volume mmcf	**Small** Gas Volume mmcf	**Large** Gas Volume mmcf	**Medium** Gas Volume mmcf	**Small** Gas Volume mmcf	**Large** Gas Volume mmcf	**Medium** Gas Volume mmcf	**Small** Gas Volume mmcf
2006	414	92	29	451	120	57	406	91	26
2007	289	70	18	316	89	38	284	68	17
2008	226	57	10	248	73	19	223	56	9
2009	188	47	8	205	61	15	185	47	7
2010	150	36	6	164	45	12	147	35	5
2011	118	20	5	130	27	11	117	21	4
2012	92	14		100	18		90	14	
2013	71	10		77	12		69	9	
2014	53	7		58	9		52	7	
2015	41	7		45	7		40	6	
2016	33	4		36	5		31	4	
2017	26	2		28	4		25	2	
2018	21	2		22	4		20	2	
2019	16	2		17	4		16	2	
2020	12	2		13	4		12	2	
2021	9	1		10	1		10	1	
2022	8			8			8		
2023	7			7			7		
2024	5			5			5		
2025	3			3			3		
2026	2			2			2		
2027	2			2			2		
2028	2			2			2		
2029	2			2			2		
2030	2			2			2		
2031	2			2			2		
2032	2			2			2		
2033	1			1			1		
2034									
2035									
2036									
2037									
2038									
2039									
2040									
2041									
2042									
2043									
2044									
Total	**1,798**	**374**	**76**	**1,958**	**481**	**153**	**1,769**	**367**	**68**

TABLE A.I.7 – PSAC 6 Typical Wells
PRODUCTION PROFILE (RAW NATURAL GAS - MMCFE)

	$6.75			$3.50			$9.00		
Year	Large Gas Volume mmcf	Medium Gas Volume mmcf	Small Gas Volume mmcf	Large Gas Volume mmcf	Medium Gas Volume mmcf	Small Gas Volume mmcf	Large Gas Volume mmcf	Medium Gas Volume mmcf	Small Gas Volume mmcf
2006	385	144	29	397	180	57	378	139	27
2007	322	101	22	336	127	42	320	99	20
2008	263	75	9	274	94	17	262	73	8
2009	215	57	7	224	71	13	213	55	6
2010	172	43	7	180	55	14	171	43	6
2011	144	32	7	150	40	14	142	31	6
2012	117	25	6	122	31	12	117	24	5
2013	95	18		100	23		96	18	
2014	79	14		83	18		79	13	
2015	67	10		70	12		66	11	
2016	56	7		58	10		56	8	
2017	48	6		50	7		46	6	
2018	40	4		41	6		40	4	
2019	33	2		35	4		34	2	
2020	28	2		30	4		29	2	
2021	25	2		26	4		25	2	
2022	21	1		22	2		21	1	
2023	18			19			19		
2024	15			15			15		
2025	13			13			13		
2026	11			11			11		
2027	9			10			9		
2028	8			8			7		
2029	7			7			7		
2030	5			6			5		
2031	5			6			5		
2032	4			4			4		
2033	4			4			4		
2034	4			4			4		
2035	3			3			3		
2036	1			2			1		
2037	1			2			1		
2038				2			1		
2039				2			1		
2040				2					
2041									
2042									
2043									
2044									
Total	**2,216**	**544**	**87**	**2,318**	**685**	**168**	**2,202**	**532**	**78**

TABLE A.I.8 – PSAC 7 Typical Wells
PRODUCTION PROFILE (RAW NATURAL GAS - MMCFE)

	$6.75			$3.50			$9.00		
Year	Large Gas Volume mmcf	Medium Gas Volume mmcf	Small Gas Volume mmcf	Large Gas Volume mmcf	Medium Gas Volume mmcf	Small Gas Volume mmcf	Large Gas Volume mmcf	Medium Gas Volume mmcf	Small Gas Volume mmcf
2006	635	127	43	759	196	94	634	125	41
2007	485	98	32	581	152	73	484	97	32
2008	378	79	23	452	123	52	378	79	23
2009	293	56	13	350	87	32	292	56	14
2010	225	41	8	270	64	16	225	41	7
2011	174	28	8	208	42	16	173	27	7
2012	131	19	2	157	29	4	131	18	2
2013	100	15		119	22		100	14	
2014	76	10		91	15		75	9	
2015	58	6		69	11		57	6	
2016	44	4		53	7		44	4	
2017	34	4		40	5		33	4	
2018	26	4		31	5		26	4	
2019	20	1		25	2		20	1	
2020	17			20			16		
2021	14			17			13		
2022	12			13			11		
2023	10			11			10		
2024	8			8			7		
2025	7			7			6		
2026	5			6			5		
2027	5			6			4		
2028	4			4			4		
2029	2			2			2		
2030	2			2			2		
2031	2			2			2		
2032	2			2			2		
2033	2			2			2		
2034	1			1			1		
2035				0					
2036									
2037									
2038									
2039									
2040									
2041									
2042									
2043									
2044									
Total	2,770	491	130	3,308	759	286	2,761	486	126

TABLE A.I.9 – RAW GAS COMPOSITION

Well	He (Helium)	N_2 (Nitrogen)	CO_2 (Carbon Dioxide)	H_2S (Sulphur)	C_1 (Methane)	C_2 (Ethane)	C_3 (Propane)	C_4 (Butane)	C_5+ (Pentane)	Total
PSAC 1 Large	0.01%	0.40%	3.67%	3.54%	85.59%	4.34%	1.31%	0.55%	0.59%	100%
PSAC 1 Med	0.02%	0.67%	3.42%	4.19%	84.62%	4.40%	1.43%	0.59%	0.66%	100%
PSAC 1 Small	0.03%	0.95%	2.79%	3.35%	83.35%	5.62%	2.18%	0.93%	0.80%	100%
PSAC 2 Large	0.04%	1.02%	2.20%	1.74%	83.49%	6.53%	2.77%	1.17%	1.04%	100%
PSAC 2 Med	0.06%	1.24%	1.77%	0.35%	83.91%	7.16%	3.18%	1.34%	0.99%	100%
PSAC 2 Small	0.07%	1.37%	1.88%	0.50%	84.18%	6.74%	3.01%	1.26%	0.99%	100%
PSAC 3 Large	0.13%	3.32%	0.38%	0.03%	93.61%	1.48%	0.58%	0.26%	0.21%	100%
PSAC 3 Med	0.13%	3.18%	0.20%	0.01%	95.78%	0.48%	0.13%	0.06%	0.03%	100%
PSAC 3 Small	0.13%	3.17%	0.25%	0.03%	95.67%	0.52%	0.14%	0.06%	0.03%	100%
PSAC 4 Large	0.08%	3.83%	0.22%	0.00%	93.72%	1.60%	0.33%	0.14%	0.08%	100%
PSAC 4 Med	0.07%	3.86%	0.21%	0.00%	93.54%	1.67%	0.38%	0.16%	0.11%	100%
PSAC 4 Small	0.07%	3.80%	0.19%	0.00%	93.67%	1.49%	0.44%	0.22%	0.12%	100%
PSAC 5 Large	0.06%	2.32%	1.23%	0.08%	89.61%	3.91%	1.54%	0.77%	0.48%	100%
PSAC 5 Med	0.06%	2.27%	0.86%	0.06%	92.88%	2.33%	0.87%	0.41%	0.26%	100%
PSAC 5 Small	0.06%	2.28%	0.85%	0.05%	92.54%	2.51%	0.96%	0.46%	0.29%	100%
PSAC 6 Large	0.02%	1.04%	1.07%	0.00%	96.99%	0.76%	0.05%	0.02%	0.05%	100%
PSAC 6 Med	0.03%	1.12%	0.97%	0.00%	97.62%	0.19%	0.03%	0.01%	0.03%	100%
PSAC 6 Small	0.03%	1.25%	0.79%	0.00%	97.41%	0.42%	0.05%	0.01%	0.04%	100%
PSAC 7 Large	0.06%	1.37%	2.12%	1.05%	91.06%	2.43%	0.99%	0.48%	0.44%	100%
PSAC 7 Med	0.06%	1.37%	2.12%	1.05%	91.06%	2.43%	0.99%	0.48%	0.44%	100%
PSAC 7 Small	0.06%	1.37%	2.12%	1.05%	91.06%	2.43%	0.99%	0.48%	0.44%	100%

TABLE A.I.10 – NATURAL GAS LIQUIDS RECOVERY EFFICIENCY

	C_2 (Ethane)	C_3 (Propane)	C_4 (Butane)	C_5+ (Pentane)
Liquids Recovery Efficiency	80%	90%	95%	95%

Oil Wells

Table A.11 provides information on the quality information for the typical wells. Tables A.12 to A.16 provide the production profiles assumed for the typical oil wells. The analysis uses butane as proxy for all liquid yields coming from solution gas and used 10 bbls butane/MMcf and Butane price to represent the blend of C3, C4, and C5.

TABLE A.I.11 – CRUDE OIL API CONTENT PER PSAC AREA

PSAC Area	2	3	4	5	7
API	39.5	22	17.7	34.9	39.4

TABLE A.I.12 – PSAC 2
PRODUCTION PROFILE (TYPICAL CONVENTIONAL OIL WELLS)

	PSAC 2											
	P10				P50				P90			
	Oil MSTB	Gas MMcf	Butane MSTB	Boe	Oil MSTB	Gas MMcf	Butane MSTB	Boe	Oil MSTB	Gas MMcf	Butane MSTB	Boe
2006	52.9	205.5	2.1	89.2	13.8	53.6	0.5	23.3	1.2	4.6	0.1	2.0
2007	31.3	121.8	1.2	52.9	8.3	32.1	0.3	13.9	0.8	3.1	0.0	1.3
2008	22.9	88.9	0.9	38.6	6.1	23.8	0.2	10.3	0.8	3.0	0.0	1.3
2009	16.7	64.8	0.7	28.1	4.6	17.7	0.2	7.7	0.8	2.9	0.0	1.3
2010	12.2	47.3	0.5	20.5	3.4	13.2	0.1	5.7	0.2	0.8	0.0	0.3
2011	8.9	34.5	0.3	15.0	2.5	9.8	0.1	4.2				
2012	6.5	25.2	0.3	10.9	1.9	7.3	0.1	3.2				
2013	4.7	18.4	0.2	8.0	1.4	5.4	0.1	2.3				
2014	3.4	13.4	0.1	5.8	1.0	4.0	0.0	1.7				
2015	2.5	9.8	0.1	4.2	0.5	2.0	0.0	0.9				
2016	1.8	7.1	0.1	3.1								
2017	1.3	5.2	0.1	2.3								
2018	1.0	3.8	0.0	1.7								
2019	0.3	1.2	0.0	0.5								
2020												
2021												
2022												
Total	**166.4**	**646.8**	**6.5**	**280.6**	**43.4**	**168.8**	**1.7**	**73.3**	**3.7**	**14.4**	**0.2**	**6.2**

TABLE A.I.13 – PSAC 3
PRODUCTION PROFILE (TYPICAL CONVENTIONAL OIL WELLS)

	PSAC 3											
	P10				P50				P90			
	Oil MSTB	Gas MMcf	Butane MSTB	Boe	Oil MSTB	Gas MMcf	Butane MSTB	Boe	Oil MSTB	Gas MMcf	Butane MSTB	Boe
2006	57.3	68.1	0.7	69.3	18.4	21.9	0.2	22.2	1.4	1.7	0.0	1.7
2007	37.4	44.5	0.4	45.3	12.0	14.3	0.1	14.6	1.0	1.2	0.0	1.2
2008	25.5	30.3	0.3	30.8	8.3	9.8	0.1	10.0	0.8	0.9	0.0	0.9
2009	17.3	20.6	0.2	21.0	5.7	6.7	0.1	6.8	0.6	0.7	0.0	0.7
2010	11.8	14.0	0.1	14.3	3.9	4.6	0.1	4.7	0.5	0.5	0.0	0.5
2011	8.0	9.6	0.1	9.7	2.7	3.2	0.0	3.2	0.1	0.1	0.0	0.1
2012	5.5	6.5	0.1	6.6	1.8	2.2	0.0	2.2				
2013	3.7	4.4	0.0	4.5	1.3	1.5	0.0	1.5				
2014	2.5	3.0	0.0	3.1	0.9	1.0	0.0	1.0				
2015	1.7	2.1	0.0	2.1	0.6	0.7	0.0	0.7				
2016	1.2	1.4	0.0	1.4	0.3	0.4	1.0	1.4				
2017	0.8	1.0	0.0	1.0								
2018	0.6	0.7	0.0	0.7								
2019	0.2	0.3	0.0	0.3								
2020												
2021												
2022												
Total	**173.6**	**206.4**	**2.1**	**210.1**	**55.7**	**66.2**	**1.7**	**68.4**	**4.3**	**5.0**	**0.1**	**5.2**

TABLE A.I.14 – PSAC 4
PRODUCTION PROFILE (TYPICAL CONVENTIONAL OIL WELLS)

	PSAC 4											
	P10				P50				P90			
	Oil MSTB	Gas MMcf	Butane MSTB	Boe	Oil MSTB	Gas MMcf	Butane MSTB	Boe	Oil MSTB	Gas MMcf	Butane MSTB	Boe
2006	31.6	11.0	0.1	33.6	9.6	3.4	0.0	10.2	1.2	0.4	0.0	1.2
2007	22.1	7.7	0.1	23.5	6.7	2.4	0.0	7.2	0.9	0.3	0.0	0.9
2008	16.7	5.8	0.1	17.7	5.1	1.8	0.0	5.4	0.7	0.3	0.0	0.8
2009	12.6	4.4	0.0	13.3	3.9	1.4	0.0	4.1	0.6	0.2	0.0	0.6
2010	9.5	3.3	0.0	10.1	3.0	1.0	0.0	3.2	0.5	0.2	0.0	0.5
2011	7.2	2.5	0.0	7.6	2.3	0.8	0.0	2.4	0.4	0.2	0.0	0.4
2012	5.4	1.9	0.0	5.7	1.7	0.6	0.0	1.8	0.1	0.1	0.0	0.1
2013	4.1	1.4	0.0	4.3	1.3	0.5	0.0	1.4				
2014	3.1	1.1	0.0	3.2	1.0	0.4	0.0	1.1				
2015	2.3	0.8	0.0	2.5	0.8	0.3	0.0	0.8				
2016	1.7	0.6	0.0	1.9	0.6	0.2	0.0	0.6				
2017	1.3	0.5	0.0	1.4	0.4	0.2	0.0	0.5				
2018	1.0	0.4	0.0	1.1	0.1	0.0	0.0	0.1				
2019	0.8	0.3	0.0	0.8								
2020	0.6	0.2	0.0	0.6								
2021	0.4	0.2	0.0	0.5								
2022	0.0	0.2	0.0	0.0								
Total	**120.2**	**42.1**	**0.5**	**127.7**	**36.5**	**12.7**	**0.2**	**38.8**	**4.4**	**1.5**	**0.0**	**4.6**

TABLE A.I.15 – PSAC 5
PRODUCTION PROFILE (TYPICAL CONVENTIONAL OIL WELLS)

	PSAC 5											
	P10				P50				P90			
	Oil MSTB	Gas MMcf	Butane MSTB	Boe	Oil MSTB	Gas MMcf	Butane MSTB	Boe	Oil MSTB	Gas MMcf	Butane MSTB	Boe
2006	60.9	138.4	1.4	85.3	10.6	24.2	0.2	14.9	1.2	2.6	0.0	1.6
2007	37.0	84.1	0.8	51.9	6.5	14.8	0.2	9.1	0.7	1.7	0.0	1.0
2008	27.6	62.8	0.6	38.7	4.9	11.2	0.1	6.9	0.6	1.4	0.0	0.9
2009	20.6	46.9	0.5	28.9	3.7	8.4	0.1	5.2	0.5	1.2	0.0	0.8
2010	15.4	35.0	0.4	21.6	2.8	6.4	0.1	3.9	0.5	1.0	0.0	0.6
2011	11.5	26.1	0.3	16.1	2.1	4.8	0.1	3.0	0.4	0.8	0.0	0.5
2012	8.6	19.5	0.2	12.0	1.6	3.6	0.0	2.2				
2013	6.4	14.6	0.2	9.0	1.2	2.8	0.0	1.7				
2014	4.8	10.9	0.1	6.7	0.9	2.1	0.0	1.3				
2015	3.6	8.1	0.1	5.0	0.7	1.6	0.0	1.0				
2016	2.7	6.1	0.1	3.7	0.5	1.2	0.0	0.7				
2017	2.0	4.5	0.1	2.8	0.3	0.7	0.0	0.4				
2018	1.5	3.4	0.0	2.1								
2019	1.1	2.5	0.0	1.6								
2020	0.8	1.9	0.0	1.2								
2021	0.6	1.4	0.0	0.9								
2022	0.5	1.1	0.0	0.6								
Total	**205.5**	**467.2**	**4.7**	**288.1**	**35.9**	**81.6**	**0.8**	**50.3**	**3.9**	**8.8**	**0.1**	**5.4**

TABLE A.I.16 – PSAC 7
PRODUCTION PROFILE (TYPICAL CONVENTIONAL OIL WELLS)

	PSAC 7											
	P10				P50				P90			
	Oil MSTB	Gas MMcf	Butane MSTB	Boe	Oil MSTB	Gas MMcf	Butane MSTB	Boe	Oil MSTB	Gas MMcf	Butane MSTB	Boe
2006	87.4	211.7	2.1	124.8	20.2	48.9	0.5	28.8	2.2	5.3	0.1	3.1
2007	54.1	131.0	1.3	77.2	12.6	30.5	0.3	17.9	1.5	3.6	0.0	2.1
2008	35.4	85.7	0.9	50.5	8.4	20.2	0.2	11.9	1.2	2.8	0.0	1.6
2009	23.1	56.0	0.6	33.0	5.6	13.5	0.1	7.9	0.9	2.2	0.0	1.3
2010	15.1	36.6	0.4	21.6	3.7	8.9	0.1	5.3	0.3	0.7	0.0	0.4
2011	9.9	24.0	0.2	14.1	2.5	5.9	0.1	3.5				
2012	6.5	15.7	0.2	9.2	1.6	3.9	0.0	2.3				
2013	4.2	10.3	0.1	6.0	1.1	2.6	0.0	1.5				
2014	2.8	6.7	0.1	3.9	0.4	0.9	0.0	0.5				
2015	1.8	4.4	0.0	2.6								
2016	1.2	2.9	0.0	1.7								
2017	0.5	1.3	0.0	0.7								
2018												
2019												
2020												
2021												
2022												
Total	**241.8**	**586.1**	**5.9**	**345.4**	**55.8**	**135.4**	**1.4**	**79.7**	**6.0**	**14.5**	**0.2**	**8.6**

Appendix II: Cost Assumptions

This appendix is divided into three parts. The first deals with the relationship between costs and prices. The second part identifies the assumptions for capital costs, while the third part identifies operating costs.

2.1 Relationship of Costs and Prices
Costs in this report were determined to be sensitive to oil and gas prices. The methodology from AE analysis on the price and cost relationship is presented below.

Capital Costs
The relationship between capital costs and price intuitively seems direct. Higher prices yield more activity; more activity puts demand on drilling rigs and other inputs, and subsequently causes input costs and day rates to increase. The opposite is also true, lower prices create less activity and therefore reduce demand for inputs causing costs to decline.

The analysis is based on the PSAC well cost data over the period of 2001-2005. During this period price expectations[22] increased by 22.8% while drilling costs change at a pace of 22.9%. Observe that 9 of the individual cost components are responsible for 77% of cost increase.

Given the strong relationship noted, it would be reasonable to assume a one to one correlation in drilling and completion costs with prices. That is, a 100% increase (or decrease) in price will yield a 100% increase (or decrease) in drilling and completion costs.

These results are similar than those shown by the Conference Board of Canada in its Canada's oil and Gas Industry outlook released in Summer 2006. the report conclude that in 2005 revenue growth for the industry was 16.5% and capital cost increase was 13% which suggest that for 100% change in industry revenue there is a 79% change in capital costs. ADOE calculated a 67% change in capital cost per every 100% change in current prices. However, the department considers price expectation to be more accurate to use given that industry drilling activity is based on producers' price expectations and not on current prices.

[22] Taken from GLJ Energy Publications.

Table A.II.1 - Drilling Cost

All Wells

	2001	2002	2003	2004	2005	2001-2005 Change	2001-2005 % Change
Drilling							
Camp and subsistence	1,418,254	1,415,784	1,413,719	1,533,654	1,637,075	218,821	15%
Daywork (inc. pipe rental)	6,189,775	6,225,675	6,895,000	6,426,100	8,428,600	2,238,825	36%
Fuel and Power	422,664	440,414	667,476	859,211	1,470,825	1,048,161	248%
Preparation and roads	1,429,101	1,429,101	1,436,226	1,822,313	1,732,219	303,118	21%
Prod. Csg and access.	678,886	575,212	575,212	785,114	1,151,119	472,233	70%
Service rig	743,920	956,540	1,248,000	1,277,720	1,745,710	1,001,790	135%
Supervision and consulting	773,325	771,525	777,825	801,850	933,900	160,575	21%
Tubing and access.	509,520	532,000	549,090	635,683	700,235	190,715	37%
price	5.40	3.88	6.12	6.31	7.87		
Total	**12,165,450**	**2,260,069**	**13,562,554**	**31,941,342**	**17,799,691**	**5,634,240**	**46%**
Total drill, case and completion est.	**31,960,688**	**32,168,876**	**33,924,278**	**34,523,922**	**39,276,964**	**7,316,276**	**22.9%**
Price Expectations	4.86	4.35	4.80	4.95	5.97	1.11	**22.8%**
Current Price AECO	5.52	3.49	5.96	5.84	7.42	1.90	**34.4%**

Operating Cost

The link between operating costs and prices is not as obvious as the link between prices and capital costs. Although a few components that comprise the cost to operate a well can be traced directly to oil and gas prices, many of the individual components that are required to maintain and operate a well have very little relationship with prevailing commodity prices. Given this, ADOE utilitized four different methodologies to test this relationship. The results suggest an assumption of a 33.3% change in operating cost for every 100% change in price appears reasonable. The four methodologies are:

1. Comparison of the inflation of an operating cost index with a more general measure of inflation, namely an index of gross domestic product (GDP). Current operating costs used for our base case ($6.75) were deflated using a unit operating cost index that was calculated using CAPP information[23] to the year 2002 when average AECO prices were $3.49. Then, the resulting costs were inflated using Canada's GDP to obtain costs for the low case scenario ($3.50). After having prices and costs for the base and low case scenarios, percentage changes were calculated at 48% for prices [(6.75-3.5)/6.75] and 19% for operating costs using the same methodology. These results show that for every dollar change in price there is a 40% change in operating cost.
2. A regression analysis was conducted with operating cost being a function of the previous year operating cost and current prices. The rational is that operators would charge this year what they charged last year plus/minus a

[23] Unit operating cost was calculated by taking CAPP total operating expenditures and multiplying it by an operating gas wells/total operating wells (oil+gas) ratio. The resulting gas operating expenditure was divided by total raw gas production. Then an index was calculating by dividing by the 2001 value thereby setting 2001=1.

fraction that is dependant of price change. Results show that for every dollar change in price there is a 9.7% change in operating costs.

3. The cost/price elasticity was calculated by looking at the % change in current prices from 2005 to 2002 (period when current price was close to $3.50) as well as the % changes in unit operating cost in the same period. These results show that operating costs changed 34% while prices change 114% hence for a dollar change in prices there is a 30% change in operating costs.
4. A fourth methodology was calculated using previous Ziff studies on operating costs with data covering the period 1998-2001. The studies reveal that seven components of cost were increasing a significantly greater rate than the remainder of the costs over this time period and are therefore assumed to be the most sensitive to price changes. All operating cost during the period increase by 68% while these seven items increase by 129%. The seven items represented about half of the total operating costs in 1998 and this had increased to 68% of total operating costs by 2001. Meanwhile, expected prices increased by 145%. This study shows that about half to two thirds of operating costs are sensitive to price. Given this relationship (50% to 68% of operating costs components has a 90% correlation with price) it would be reasonable to assume that for every dollar change in price there is a 50% change in operating cost based on this methodology.

2.2 Capital Cost

In order to complete the analysis of typical wells, additional assumptions were required to reflect the investment and the ongoing costs associated with oil and gas production. Cost assumptions: land, success rates, seismic, drilling, tie in and equip, lease operating, gathering, compression, processing.

Land costs were developed based on lease sale information gathered by the ADOE. Regression analysis in each PSAC area were conducted assuming that $/hectare paid by producers was a function of expected commodity prices. Expected commodity prices were derived from past commodity price forecasts (using a 5 year average) by GLJ Energy Publication. Regression results in table A.17 show a strong predictive value for expected prices and the amount of $/hectare bid by producers. In most cases the R^2 is near 90 percent and the coefficient for expected price is significant.[24] After calculating this regression, expected $/hectare amount were calculated having as an expected price those of the low, base and high case scenarios. That is $30, $50 and $75/bbl for oil and $3.50, $6.75 and $9.00/Mcf for natural gas. Then these results were multiplied by a 10 year average hectare per well in each PSAC are of production to come up to a result that is expressed on a $/well bases. Tables A.18 and A.19 shows land bonus bids used for each scenario.

[24] That is the null hypothesis that the coefficient on expected price is zero is rejected at the 99% confidence level.

TABLE A.II.17 – REGRESSION RESULTS

	Bonus Bid Regression Results		
	Expected Price	T-Statistic	R^2
PSAC 1	153.07	5.82	69.3%
PSAC 2	136.37	12.2	90.8%
PSAC 3	58.7	11.27	89.5%
PSAC 4	62.46	12.75	91.6%
PSAC 5	70.75	10.46	87.9%
PSAC 6	36.73	8.31	82.1%
PSAC 7	54.7	12.35	91.0%

TABLE A.II.18 – LAND BONU.S. BID PER CONVENTIONAL OIL WELL

	$30.00	$50.00	$75.00
PSAC 2	$64,000	$109,000	$145,000
PSAC 3	$15,000	$30,000	$40,000
PSAC 4	$14,000	$27,000	$36,000
PSAC 5	$30,000	$57,000	$76,000
PSAC 7	$36,000	$69,000	$92,000

TABLE A.II.19 – LAND BONU.S. BID PER GAS WELL

	$3.50	$6.75	$9.00
PSAC 1	$788,469	$1,520,618	$2,027,491
PSAC 2	$255,327	$434,560	$579,414
PSAC 3	$61,987	$119,546	$159,395
PSAC 4	$56,140	$108,270	$144,360
PSAC 5	$118,661	$228,847	$305,129
PSAC 6	$77,199	$148,885	$198,513
PSAC 7	$143,252	$276,271	$368,361

Seismic costs were developed using Petro-Cube Software. Table A.20 contains a summary of Seismic costs used. Notice that seismic costs were assumed to be constant for the three price case scenarios.

TABLE A.II.20 – SEISMIC COST PER WELL

	$ M
PSAC 1	$212
PSAC 2	$20
PSAC 3	$9
PSAC 4	$5
PSAC 5	$17
PSAC 6	$10
PSAC 7	$36

Success rates were established based on statistical analysis of the drilling activity in Alberta over the last 5 years. Wells that have oil production or gas wells that were connected were assumed to be successful. The success rate was calculated as the number of successful wells divided by the total number of wells drilled. Bitumen and service wells were excluded. The success rates were adjusted to reflect the price scenarios. That is at higher prices more wells were successful; however the amount of production from a successful well is similarly adjusted as described previously. From Technical Report #1 it is clear that at lower prices some lower productivity wells would not be drilled. There is no way of determining ex-post what wells would or would not have been drilled if prices had been different. As such it was assumed that wells that did not have sufficient revenues to cover operating costs were considered not drilled. That is the number of successful wells was reduced by the number of uneconomic wells. The number of unsuccessful wells was not adjusted. The result is a reduction in success rates at lower prices that ranged from 1 to 7 percentage points depending on the region. These lower success rates were consistent with success rates from the late 1990's when natural gas prices ranged from $1/Mcf to $3/Mcf.[25] Table A.21 provides the success rates calculated for each PSAC area.

TABLE A.II.21 – SUCCESS RATES

	Conventional Oil							
PSAC Area	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**Average**
Success Rate	58.7%	75.9%	88.9%	80.4%	71.9%	56.9%	62.2%	78.4%

	Natural Gas $6.75							
PSAC Area	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**Average**
Success Rate	58.4%	75.5%	88.8%	79.7%	70.9%	56.5%	59.5%	77.0%

	Natural Gas $3.50							
PSAC Area	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**Average**
Success Rate	57.7%	74.8%	88.0%	78.1%	68.9%	56.2%	55.4%	71.8%

	Natural Gas $9.00							
PSAC Area	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**Average**
Success Rate	58.4%	75.5%	88.8%	79.8%	71.1%	56.6%	59.5%	77.3%

Drilling costs were assumed to be a function of depth and were developed based on the information from the annual PSAC well cost studies. Various years were used to assist in developing the relationship between cost and depth; however, only the most recent year was used to determine the magnitudes. The depth and drilling cost assumptions are presented for oil in Table A.22 and in Table A.23 for natural gas. The depths were arrived at by analyzing all of the wells drilled in these areas over the last 5 years. For most areas, there was a large number of wells concentrated over a small range in depth, however, areas 5 and 7 there was a linear progression in depths reflecting the changing geology that exists within these two regions. For this reason, three depths were chosen for areas 5 and 7 as noted in the table.

[25] Price should influence the success rate. At higher prices smaller wells are economic, and conversely at lower prices the same wells are no longer economic. Two alternative approaches were considered for treating wells that were not half-cycle economic. The idea of treating these wells as unsuccessful was considered and dismissed as clearly some wells were induced when prices were substantially above the lower gas price of $3.50/Mcf in the data range analyzed. Similarly, the approach of using the ratio of successful wells to unsuccessful wells to apportion the wells that were not economic on a half-cycle basis was also rejected as this would result in no reduction to the success rate.

TABLE A.II.22 – DRILLING COST PER CONVENTIONAL OIL WELL ($000)

		Drilling & Completion		
	Depth (metres)	$30.00	$50.00	$75.00
PSAC 2	2,132	937	1,808	2,411
PSAC 3	1,119	416	803	1,070
PSAC 4	754	282	544	726
PSAC 5	1,525	592	1,143	1,524
PSAC 7	1,619	596	1,149	1,532

		Drilling & Abandonment		
	Depth (metres)	$30.00	$50.00	$75.00
PSAC 2	2,132	649	1,252	1,670
PSAC 3	1,119	243	469	626
PSAC 4	754	141	273	364
PSAC 5	1,525	405	782	1,042
PSAC 7	1,619	320	617	823

TABLE A.II.23 – DRILLING COST PER GAS WELL ($000)

	Depth (Metres)	$3.50	$6.75	$9.00
PSAC 1	3,494	2,381	4,592	6,123
PSAC 2	2,412	1,118	2,157	2,876
PSAC 3	751	129	248	331
PSAC 4	711	245	473	631
PSAC 6	495	144	277	369
PSAC 5 Small (P25)	737	254	489	652
PSAC 5 Med (P50)	1,024	342	659	879
PSAC 5 Large (P80)	1,608	521	1,005	1,340
PSAC 5 Ave	1,134	375	724	965
PSAC 7 Small (P25)	351	94	182	243
PSAC 7 Med (P50)	612	136	262	349
PSAC 7 Large (P80)	1,557	268	516	688
PSAC 7 Ave	904	199	384	512

ADOE determined (using information on drilling and completion cost and expected prices from 1999 to 2005) that for every 100% change in expected commodity prices, there is a change of 100% in drilling and completion costs. This relationship was used to adjust costs for the high and low case scenario for drilling as well as for tie-in and equipment costs. That is that both prices and costs increase 33.3% from the base case to the high case scenario. On the other hand prices and cost decrease 48% for the low case scenario.

Tie-in and equipment costs were based on the distance from an existing gathering system and the product mix from the well and were developed using Petro-Cube Software with comparisons made to information collected through the Petroleum Registry.[26] Table A.24 provides the equipment cost assumptions used for oil wells. The tie-in and equipment costs for gas wells are presented in Table A.25

TABLE A.II.24 –EQUIPMENT COSTS PER CONVENTIONAL OIL WELL

	$30	$50	$75
PSAC 2	$29	$55	$73
PSAC 3	$30	$57	$76
PSAC 4	$29	$56	$75
PSAC 5	$30	$57	$76
PSAC 7	$30	$57	$76

TABLE A.II.25– TIE-IN AND EQUIPMENT COSTS PER GAS WELL

	$3.50 Tie-in $M	$6.75 Tie-in $M	$9.00 Tie-in $M
PSAC 1	$224	$432	$576
PSAC 2	$144	$278	$371
PSAC 3	$27	$53	$71
PSAC 4	$35	$67	$89
PSAC 5	$43	$82	$109
PSAC 6	$62	$120	$160
PSAC 7	$168	$324	$432

	$3.50 Equipment $M	$6.75 Equipment $M	$9.00 Equipment $M
PSAC 1	$122	$236	$314
PSAC 2	$64	$123	$164
PSAC 3	$20	$39	$52
PSAC 4	$15	$29	$39
PSAC 5	$22	$42	$56
PSAC 6	$41	$80	$107
PSAC 7	$61	$118	$157

2.3 Operating Costs

Operating costs were developed using a combination of information from Petro-Cube software, publicly available data, and information obtained through the Petroleum Registry related to gathering, compression, and processing. ADOE determined (using information on operating cost and prices from 1999 to 2005) that for every 100% change in commodity prices, there is a change of 33.3% in operating costs. This relationship was used to adjust costs for the high and low case scenario. (e.g., Notice that prices increase 33.3% from the base case to the high case scenario and therefore costs is assumed to increase by 11.1%. Also prices decrease 48% from the base case scenario to the low case scenario and costs were assumed to decrease 16%). Table A.26 contains the operating cost assumptions used for oil wells, while the assumptions used for natural gas are presented in Table A.27. Notice that for natural gas additional assumptions are required for gas cost allowance (GCA) calculations.

[26] The Petroleum Registry of Alberta is a shared, secure, interactive database that includes volumetric and infrastructure data related to Alberta's upstream oil and gas industry. More information is available at www.petroleumregistry.gov.ab.ca.

TABLE A.II.26 OPERATING COSTS PER CONVENTIONAL OIL WELL

	$50		$30		$75	
	Fixed well $/W/M	Variable $/bbl	Fixed well $/W/M	Variable $/bbl	Fixed well $/W/M	Variable $/bbl
PSAC 2	$5,625	$5.54	$6,700	$6.60	$7,444	$7.33
PSAC 3	$3,022	$4.02	$3,600	$4.79	$4,000	$5.32
PSAC 4	$2,770	$4.98	$3,300	$5.93	$3,667	$6.59
PSAC 5	$2,435	$3.91	$2,900	$4.66	$3,222	$5.18
PSAC 7	$3,862	$4.04	$4,600	$4.81	$5,111	$5.34

TABLE A.II.27 OPERATING COSTS PER GAS WELL

$6.75

	Variable $/Mcf	Fixed well $/W/M	Fixed well GCA	GCA ADOE Proc. $/Mcf
PSAC 1	$0.59	$3,429	$1,895	$0.21
PSAC 2	$0.51	$2,501	$1,042	$0.15
PSAC 3	$0.32	$1,191	$541	$0.10
PSAC 4	$0.39	$1,630	$489	$0.09
PSAC 5	$0.37	$1,795	$760	$0.11
PSAC 6	$0.37	$2,270	$200	$0.03
PSAC 7	$0.41	$1,980	$2,293	$0.22

$3.50

	Variable $/Mcf	Fixed well $/W/M	Fixed well GCA	GCA ADOE Proc. $/Mcf
PSAC 1	$0.50	$2,879	$1,591	$0.18
PSAC 2	$0.43	$2,100	$875	$0.13
PSAC 3	$0.27	$1,000	$454	$0.08
PSAC 4	$0.33	$1,368	$411	$0.08
PSAC 5	$0.31	$1,507	$638	$0.09
PSAC 6	$0.31	$1,905	$168	$0.03
PSAC 7	$0.34	$1,662	$1,925	$0.18

$9.00

	Variable $/Mcf	Fixed well $/W/M	Fixed well GCA	GCA ADOE Proc. $/Mcf
PSAC 1	$0.66	$3,810	$2,106	$0.23
PSAC 2	$0.57	$2,779	$1,158	$0.17
PSAC 3	$0.36	$1,323	$601	$0.11
PSAC 4	$0.43	$1,811	$543	$0.10
PSAC 5	$0.41	$1,995	$844	$0.12
PSAC 6	$0.41	$2,522	$223	$0.03
PSAC 7	$0.46	$2,200	$2,548	$0.24

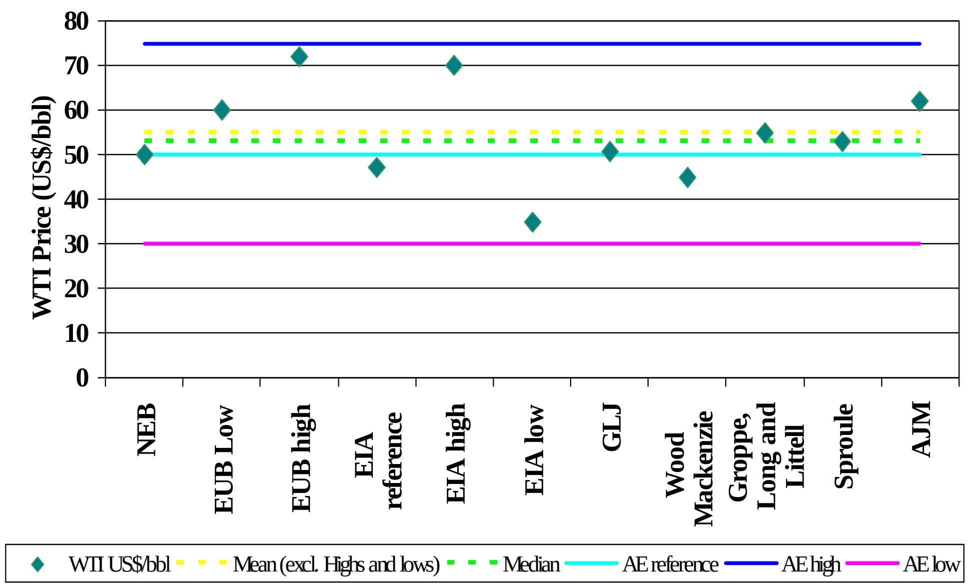
Appendix III: Oil and Gas Prices

The analysis employed starts with West Texas Intermediate (WTI) as the primary pricing reference point.[27] A planning range from low to high was constructed to facilitate evaluation of the economics and fiscal systems performance. The low price, U.S.$30 per bbl, was chosen to reflect a price close to the supply cost. This implies an oil price of CAD$30 for light oil and an AECO-C price of CAD$3.50 per Mcf for natural gas.

The medium price is U.S. $50 per bbl was used to reflect current price levels and expectations. This implies an oil price of CAD$50 at the field in Alberta for light oil and an AECO-C natural gas price of CAD$6.75 per Mcfe.
The high case scenario was chosen to reflect the possibility of even higher price. This price was set a U.S. $75 per bbl (which translates to an oil price of CAD$75 for light oil in Alberta) and an AECO-C price CAD$9.00 per Mcfe. Figure A.2 compares the oil price assumptions with other forecasts. Figure A.3 provides the same comparison for natural gas.

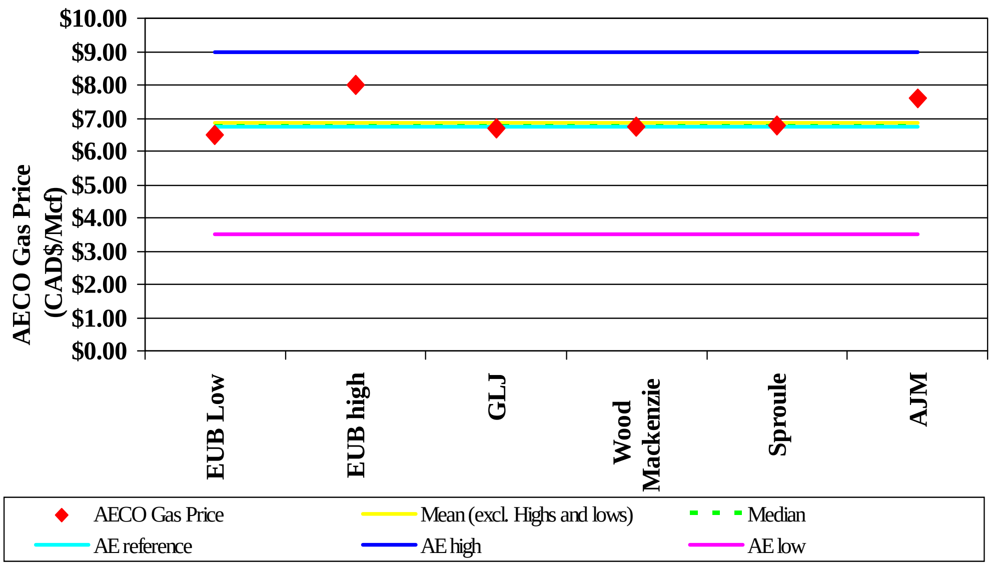
As the natural gas prices used were for gas at the AECO-C hub, an additional transportation cost of $0.30 was deducted for intra-Alberta transportation. That is, the analysis references a price at the plant gate that is $0.30 lower than the AECO-C price.

FIGURE A.III.2 OIL PRICE FORECASTS AND AE PRICE SCENARIOS



[27] It is worth noting that these WTI prices, once exchange rates and transportation costs are taken into consideration, translate in about CAD$30/bbl for field prices in Alberta. That is one barrel selling for CAD$30 in Alberta would be equivalent that a barrel selling for US$30 on NYMEX.

FIGURE A.III.3 GAS PRICE FORECASTS AND AE PRICE SCENARIOS



Conventional Oil, Natural Gas & Liquids Prices

Tables A.28 and A.29 show the price relationships between conventional oil, natural gas, and natural gas liquids. The relationship between light/medium and heavy crude oil is also shown.

TABLE A.III.28 CONVENTIONAL OIL ASSUMPTIONS

Oil Price Nominal					
Ligth Medium $/bbl			Heavy $/bbl		
Low	Med	High	Low	Med	High
30.00	50.00	75.00	21.00	35.00	52.50

TABLE A.III.29 NATURAL GAS & LIQUIDS PRICE ASSUMPTIONS

Gas Price Nominal														
Sale Gas $/Mcf			C_2 $/bbl			C_3 $/bbl			C_4 $/bbl			C_5+ $/bbl		
Low	Med	High	Low	Med	High	Low	Med	High	Low	Med	High	Low	Med	High
3.50	6.75	9.00	6.10	11.16	14.63	20.81	43.97	59.84	23.01	46.16	62.04	32.71	55.86	71.73

Appendix IV: Detailed Industry Returns Results - Alberta

TABLE A.IV.1 – NATURAL GAS ($6.75/MCF)

Alberta Gas							
	Modelled Results						
Area	Well EUR Bcf	Average Revenue $/Mcf real	EMV $000 real	EMV $/Mcf real	EMV 10% $000	EMV10% $/Mcf	$PFR_{10\%}$
PSAC 1	5.94	8.00	6536	1.88	2713	0.78	1.46
PSAC 2	1.74	8.91	2917	2.22	1409	1.07	1.54
PSAC 3	0.16	6.96	94	0.64	-37	-0.25	0.90
PSAC 4	0.43	6.84	548	1.60	255	0.75	1.43
PSAC 5	0.64	7.69	770	1.69	327	0.72	1.36
PSAC 6	0.85	6.80	1059	2.19	582	1.21	2.22
PSAC 7	0.95	7.55	1074	1.91	596	1.06	1.78
Total	1.88	8.01	2437	1.79	1093	0.76	1.39

TABLE A.IV.2 – NATURAL GAS ($3.50/MCF)

Alberta Gas							
	Modelled Results						
Area	Well EUR Bcf	Average Revenue $/Mcf real	EMV $000 real	EMV $/Mcf real	EMV 10% $000	EMV10% $/Mcf	$PFR_{10\%}$
PSAC 1	6.16	4.13	2782	0.78	1010	0.28	1.32
PSAC 2	1.87	4.60	1388	0.99	659	0.47	1.48
PSAC 3	0.22	3.57	73	0.39	6	0.03	1.03
PSAC 4	0.53	3.52	326	0.79	175	0.43	1.55
PSAC 5	0.74	3.95	407	0.80	187	0.37	1.38
PSAC 6	0.95	3.50	539	1.01	310	0.58	2.19
PSAC 7	1.23	3.89	653	0.96	395	0.58	1.94
Total	1.90	4.10	1070	0.81	468	0.34	1.37

TABLE A.IV.3 – NATURAL GAS ($9.00/MCF)

Alberta Gas							
	Modelled Results						
Area	Well EUR Bcf	Average Revenue $/Mcf real	EMV $000 real	EMV $/Mcf real	EMV 10% $000	EMV10% $/Mcf	$PFR_{10\%}$
PSAC 1	5.94	10.66	9480	2.73	4133	1.19	1.54
PSAC 2	1.74	11.87	4132	3.14	2041	1.55	1.59
PSAC 3	0.17	9.27	168	1.13	-22	-0.15	0.95
PSAC 4	0.42	9.13	768	2.28	362	1.07	1.46
PSAC 5	0.63	10.26	1074	2.39	464	1.03	1.39
PSAC 6	0.85	9.06	1463	3.04	801	1.67	2.27
PSAC 7	0.94	10.06	1527	2.72	858	1.53	1.85
Total	1.88	10.67	3490	2.57	1618	1.12	1.44

TABLE A.IV.4 – CONVENTIONAL OIL ($50/BBL)

Alberta Oil

Area	Reserves Per Well Mboe	Average Revenue $/boe real	EMV $000 real	EMV $/boe real	EMV 10% $000	EMV 10% $/Boe	$PFR_{10\%}$
	Modelled Results						
PSAC 2	107.09	40.94	-151	-1.86	-425	-5.23	0.74
PSAC 3	86.61	33.72	373	4.84	165	2.14	1.19
PSAC 4	49.35	36.35	88	2.23	-41	-1.03	0.93
PSAC 5	105.03	43.10	476	6.30	132	1.75	1.12
PSAC 7	134.33	42.95	568	6.79	296	3.54	1.28
Total	99.95	39.52	291.04	3.85	41.11	0.52	1.04

TABLE A.IV.5 – CONVENTIONAL OIL ($30/BBL)

Alberta Oil

Area	Reserves Per Well Mboe	Average Revenue $/boe real	EMV $000 real	EMV $/boe real	EMV 10% $000	EMV 10% $/Boe	$PFR_{10\%}$
	Modelled Results						
PSAC 2	107.09	23.70	-75	-0.92	-206	-2.54	0.76
PSAC 3	86.61	19.73	321	4.18	213	2.77	1.53
PSAC 4	49.35	20.97	91	2.29	31	0.78	1.11
PSAC 5	105.03	25.40	325	4.31	140	1.85	1.23
PSAC 7	134.33	25.27	381	4.56	234	2.80	1.41
Total	99.95	23.09	222.44	2.99	93.20	1.19	1.16

TABLE A.IV.6 – CONVENTIONAL OIL ($75/BBL)

Alberta Oil

Area	Reserves Per Well Mboe	Average Revenue $/boe real	EMV $000 real	EMV $/boe real	EMV 10% $000	EMV 10% $/Boe	$PFR_{10\%}$
	Modelled Results						
PSAC 2	107.09	60.87	6	0.07	-456	-5.61	0.81
PSAC 3	86.61	50.52	745	9.68	408	5.30	1.36
PSAC 4	49.35	55.49	322	8.12	96	2.43	1.13
PSAC 5	105.03	64.15	1031	13.66	473	6.26	1.31
PSAC 7	134.33	63.83	1169	13.98	724	8.66	1.52
Total	99.95	59.06	688.32	9.29	276.05	3.52	1.18

Appendix V: Detailed Government Share Results - Alberta

TABLE A.V.1 – NATURAL GAS (GOVERNMENT SHARE - $6.75/MCF)

Alberta Gas

Area	Well EUR Bcf	Royalty $000 real	Provincial Tax $000 real	Federal Tax $000 real	Bonus $000 real	Provincial Share real %	Federal Share real %	Combined Govt Share real %
	Modelled Results							
PSAC 1	5.94	12,744	1,089	2,087	1,521	54%	11%	65%
PSAC 2	1.74	4,029	482	927	435	51%	12%	63%
PSAC 3	0.16	124	30	57	120	63%	14%	77%
PSAC 4	0.43	589	99	189	108	48%	13%	61%
PSAC 5	0.64	1,105	137	262	229	53%	12%	65%
PSAC 6	0.85	1,285	171	327	149	43%	13%	56%
PSAC 7	0.95	1,603	199	381	276	50%	13%	63%
Total	1.88	3,988	410	787	500	52%	12%	64%

TABLE A.V.2 – NATURAL GAS (GOVERNMENT SHARE - $3.50/MCF)

Alberta Gas

Area	Well EUR Bcf	Royalty $000 real	Provincial Tax $000 real	Federal Tax $000 real	Bonus $000 real	Provincial Share real %	Federal Share real %	Combined Govt Share real %
	Modelled Results							
PSAC 1	6.16	6,294	483	927	788	57%	11%	68%
PSAC 2	1.87	2,097	237	456	255	53%	12%	64%
PSAC 3	0.22	74	17	33	62	58%	13%	71%
PSAC 4	0.53	340	57	109	56	47%	13%	60%
PSAC 5	0.74	608	73	139	119	53%	12%	65%
PSAC 6	0.95	702	87	167	77	44%	13%	57%
PSAC 7	1.23	933	116	221	143	47%	13%	60%
Total	1.90	1,909	186	357	256	54%	11%	66%

TABLE A.V.3 – NATURAL GAS (GOVERNMENT SHARE - $9.00/MCF)

Alberta Gas

Area	Well EUR Bcf	Royalty $000 real	Provincial Tax $000 real	Federal Tax $000 real	Bonus $000 real	Provincial Share real %	Federal Share real %	Combined Govt Share real %
	Modelled Results							
PSAC 1	5.94	16,712	1,556	2,978	2,027	52%	12%	63%
PSAC 2	1.74	5,298	677	1,299	579	49%	12%	61%
PSAC 3	0.17	165	44	83	159	58%	14%	72%
PSAC 4	0.42	772	137	262	144	47%	14%	60%
PSAC 5	0.63	1,438	188	361	305	51%	12%	64%
PSAC 6	0.85	1,693	235	448	199	42%	14%	56%
PSAC 7	0.94	2,172	279	534	368	48%	13%	62%
Total	1.88	5,241	580	1,111	666	50%	12%	62%

TABLE A.V.4– CONVENTIONAL OIL (GOVERNMENT SHARE - $50/BBL)

Alberta Oil

Area	Reserves Per Well Mboe	Royalty $000 real	Provincial Tax $000 real	Federal Tax $000 real	Bonus $000 real	Provincial Share real %	Federal Share real %	Combined Govt Share real %
	Modelled Results							
PSAC 2	107.09	783	55	195	109	102%	18%	121%
PSAC 3	86.61	457	89	207	30	48%	18%	66%
PSAC 4	49.35	208	38	93	27	58%	20%	78%
PSAC 5	105.03	813	113	299	57	51%	17%	68%
PSAC 7	134.33	1,165	126	348	69	53%	17%	71%
Total	99.95	720	88	238	60	58%	18%	76%

TABLE A.V.5 – CONVENTIONAL OIL (GOVERNMENT SHARE - $30/BBL)

Alberta Oil

Area	Reserves Per Well Mboe	Royalty $000 real	Provincial Tax $000 real	Federal Tax $000 real	Bonus $000 real	Provincial Share real %	Federal Share real %	Combined Govt Share real %
	Modelled Results							
PSAC 2	107.09	315	28	95	64	104%	20%	124%
PSAC 3	86.61	143	46	109	15	31%	17%	48%
PSAC 4	49.35	66	16	42	14	40%	17%	57%
PSAC 5	105.03	332	65	165	30	42%	18%	60%
PSAC 7	134.33	465	68	182	36	44%	18%	62%
Total	99.95	278	47	124	32	47%	18%	65%

TABLE A.V.6 – CONVENTIONAL OIL (GOVERNMENT SHARE - $75/BBL)

Alberta Oil

Area	Reserves Per Well Mboe	Royalty $000 real	Provincial Tax $000 real	Federal Tax $000 real	Bonus $000 real	Provincial Share real %	Federal Share real %	Combined Govt Share real %
	Modelled Results							
PSAC 2	107.09	1,180	123	365	145	80%	19%	100%
PSAC 3	86.61	814	150	356	40	46%	17%	63%
PSAC 4	49.35	372	72	171	36	46%	18%	64%
PSAC 5	105.03	1,220	192	483	76	44%	16%	60%
PSAC 7	134.33	1,755	213	562	92	47%	17%	64%
Total	99.95	1,122	156	403	80	51%	17%	68%