

giving away...



the Alberta Advantage.

Are Albertans receiving maximum revenue
from our oil and gas?



Giving Away the Alberta Advantage

Are Albertans Receiving Maximum Revenues from their Oil and Gas?

Prepared by the Parkland Institute, Edmonton, Alberta, November 1999

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What is the Parkland Institute?

Parkland Institute is an Alberta wide research network that examines issues of public policy. The Institute is based out of the Faculty of Arts at the University of Alberta and our research network includes members from most of Alberta's academic institutions and other organizations involved in public policy research. It operates within the established and distinctive tradition of Canadian political economy and is non-partisan. Parkland was founded in 1996 and its mandate is to:

- conduct research on economic, social, cultural and political issues facing Albertans and Canadians.
- publish research and provide informed comment on current policy issues to the media and the public.
- sponsor conferences and colloquia.
- bring together the academic and non-academic communities
- train graduate students

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Giving Away the Alberta Advantage

Are Albertans Receiving Maximum Revenues from their Oil and Gas?

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Executive Summary

Alberta's oil and gas resources are free gifts of nature and contribute significantly to Alberta's advantage. These resources can be developed or not developed at the discretion of the stewards of this resource, namely the citizens of Alberta as well as Canada. Alberta's oil and gas legacy is our most precious natural asset contributing significantly to employment, industry profits and government royalty and tax revenues. For example, in 1997-98 government revenues from oil and gas royalties amounted to \$3.78 billion or 21% of total government revenues.

But are Albertans receiving maximum value from the sale of our oil and gas resources?

"You folks did an excellent job analyzing a very difficult subject. This is especially true since Alberta did not come out as aggressive on collecting "rents" as other areas did."

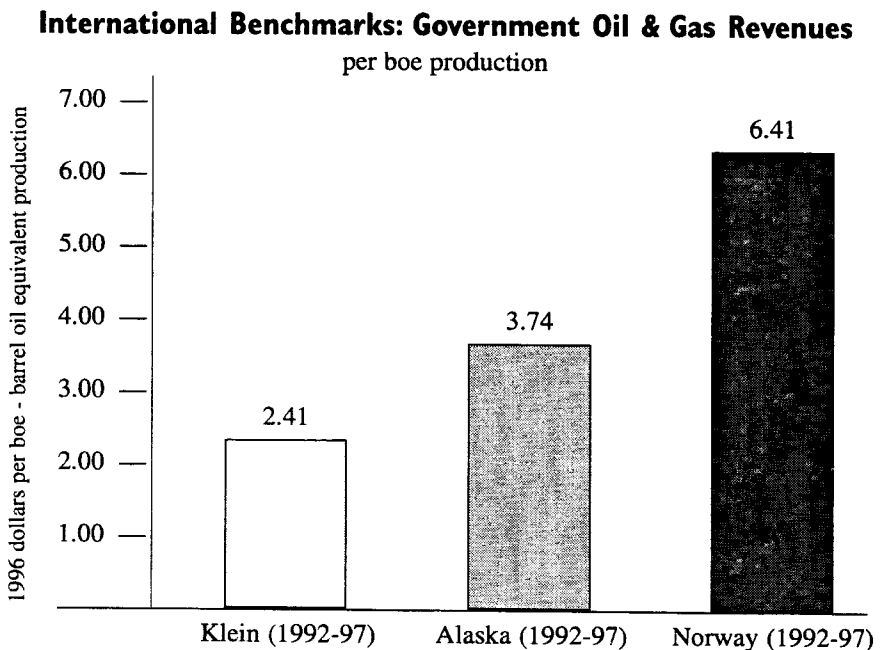
*James A. Stouffer, CPA
Royalty Accounting
Supervisor,
Alaska*

To answer this question, Parkland's researchers studied five questions:

- How does Alberta compare with other international benchmarks, like Norway and Alaska?
- How does the collection performance of the current Alberta government compare with previous administrations?
- What are the indications about Alberta's collection performance in the future?
- What is the financial impact of our current provincial policies on the collection of oil and gas revenues?
- What are the policy implications for the fiscal management and accountability of government?

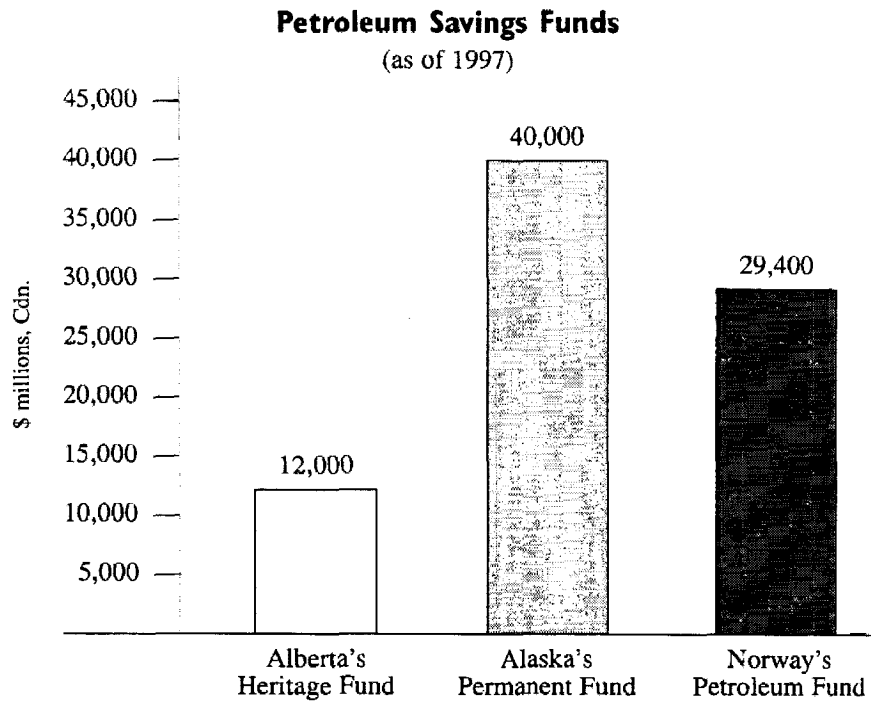
International Benchmarks

The study compared the energy "rent"* collection performance of Alberta, Alaska and Norway between 1992-1997. The study found that Alaska collected roughly 1.6 times more than Alberta in royalties and taxes for every unit (boe: barrels of oil equivalent) of oil, natural gas and byproducts produced¹. Norway collected roughly 2.7 times more than Alberta for every unit of oil and gas production in the form of royalties, income taxes, a carbon tax and revenues from a state direct financial interest through the national oil company Statoil. Specifically, between 1992-97 Alberta received an average \$2.41/boe (barrel oil equivalents) compared to \$3.74/boe for Alaska and \$6.41/boe for Norway (all figures in constant 1996 Canadian dollars).



The study also examined the rate of petroleum revenue savings in petroleum "heritage" savings funds. By April 1999 Alaskans had total savings of Cdn. \$40 billion in their Alaska "Permanent Fund." Also of significance, is that in 1998 the Fund paid a record dividend of Cdn. \$2,210 (Canadian) per Alaskan. Norway's "Petroleum Fund" had total savings of \$29.4 billion (Canadian) in 1997 and continues to grow at a significant rate with ongoing investment of oil and gas revenues. In comparison, Alberta's Heritage Fund contained \$12.0 bil-

¹ Unlike Alaska and Norway, Alberta's public accounts provide no information on corporate income taxes paid to the province or federal government by the Alberta petroleum industry. For the purposes of benchmarking Alberta with Norway and Alaska, it was necessary to use industry estimates of corporate income taxes paid. Based on financial data derived from financial statements of Canadian petroleum companies collected by Canadian Petroleum Perspectives, this study estimates that an average of \$433 million per annum between 1992-97 (in constant 1996 dollars) in both federal/provincial corporate income taxes were paid by the Alberta petroleum industry. Historical analysis excludes the corporate income tax figures.



lion in 1997 and has remained stagnant since 1986. Norway forecasts that by the year 2000 petroleum revenues collected will rise to Cdn. \$20.5 billion or \$12.42/boe, produced roughly 10 times more than Alberta's forecast of \$1.25/boe in 2000/2001. Moreover, Norway's Petroleum Fund is forecast to grow to Cdn. \$54 billion by the year 2000, even with the forecast of lower oil prices made earlier this year.

What is critical is that both Norway and Alaska have realized greater returns (royalties and taxes) for every barrel of oil and gas produced while still retaining and sustaining a healthy and prosperous energy industry, all things being equal.

* What are Oil and Gas Rents?

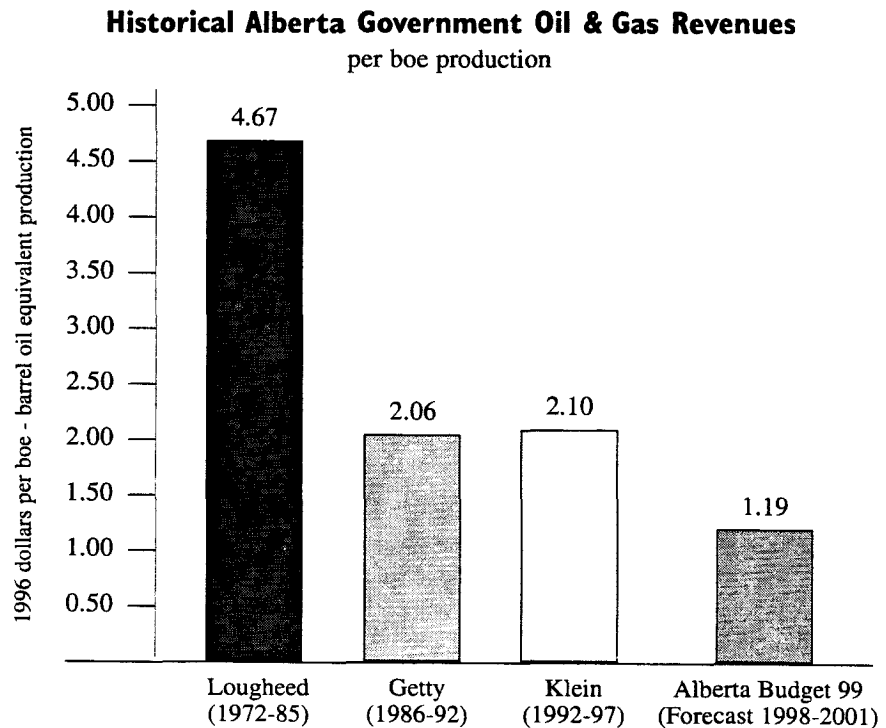
Economic rent generated by oil and gas production is the net difference between the international commodity price of oil and gas less all costs of production (including, exploration, development, operating, capital and transportation costs), including an allowance for a normal return to capital employed (profit) but before royalties, taxes, and duties. Economic rent is thus the net revenues generated from the production of oil and gas.

Royalties, fees and other taxes are used by government to collect energy rents from the producer, normally industry. In principle, 100% of the economic rent derived from oil and gas production belongs to Albertans, who are the owners or shareholders of these nonrenewable resources. In practice, however, governments seek a balance between maximizing rent collection and the objectives of economic development, investment and a fair tax regime for industry.

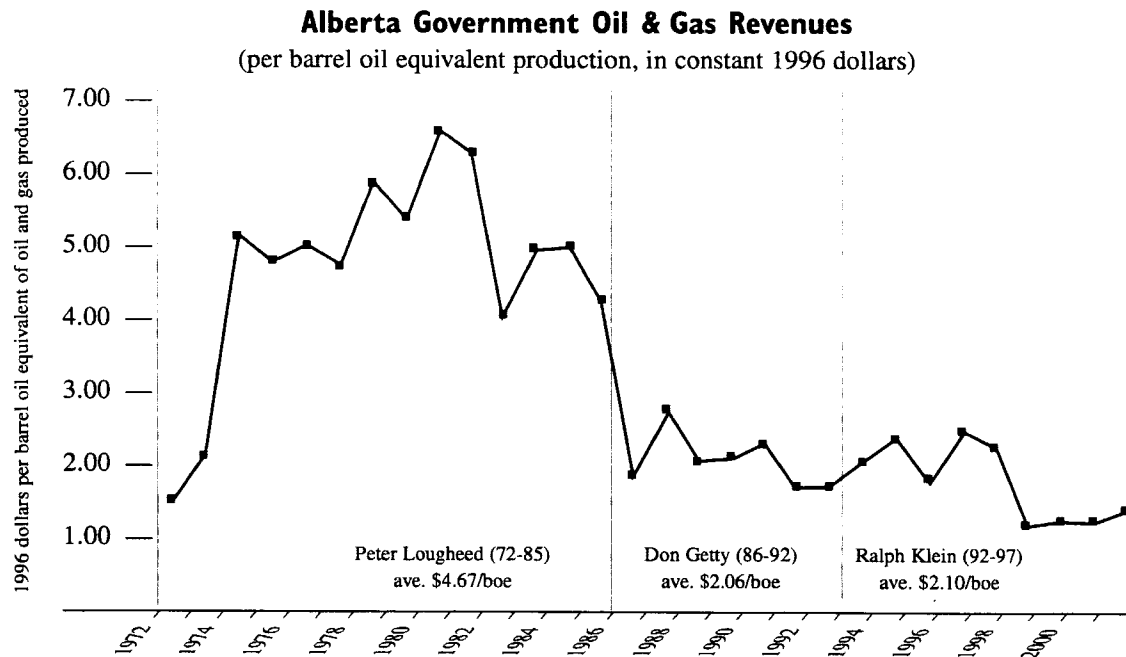
Historical Analysis

The study also examined Alberta's historical record of energy rent collection from 1972 to 1997.

Under the Klein administration, Albertans have received less than half as much in oil and gas revenues per unit of oil and gas produced than under Peter Lougheed (1971 to 1985). The Klein government collected an average \$2.10/boe (or \$3.12 billion per annum) between 1992 and 1997 while the Lougheed government collected an average \$4.67/boe (or \$4.78 billion per annum) between 1972 and 1985 (all in constant 1996 dollars).



Of course, changes in oil and gas prices, production costs and royalty regimes may have contributed to at least some of this difference. However, if we compare the amount collected on each barrel of oil and gas (boe) in constant 1996 over time, we see that we continued to collect only \$2.10 per barrel equivalent between 1992 and 1997 despite the increase in the price of oil and gas.



What About the Future?

Using forecasts from the Alberta Government's *Budget '99* for oil and gas royalties, fees and production volumes, the rents collected per unit of production are expected to reach their lowest level in three decades; \$1.25/boe (constant 1996 dollars). Oil and gas revenues are expected to decline from \$3.88 billion in 1996/97 to \$2.72 billion by 2001/2002 which equate to an unprecedented average low of \$1.25/boe (using the government's rate of inflation, this would equate to an average of \$1.19 boe) of production between fiscal years 1998 and 2000.

While part of this decline is due to a lower oil price forecast, the most significant factor in the forecast revenue decrease is a reduction in oilsands royalty revenues. Oilsands royalty revenues are expected to fall dramatically to \$22 million by 2001/2002 compared with \$512 million collected in 1996/97. On a per barrel of oil basis, oilsands will yield only \$0.08 per barrel by 2000/2001 compared to \$2.93 per barrel forecast in 1996/97.

The oilsands are Alberta's (and arguably North America's) most significant and strategic energy resource containing more oil (estimated at 300 billion barrels) than Saudi Arabia's conventional crude oil reserves (262 billion barrels). At current rates of production Alberta's oilsands could last 1,500 years. As conventional crude oil (6.9 year reserve life²) and natural gas reserves (10.5 year reserve life) are depleted, oilsands production and associated royalty revenues will become the long-term mainstay of Alberta's energy revenues.

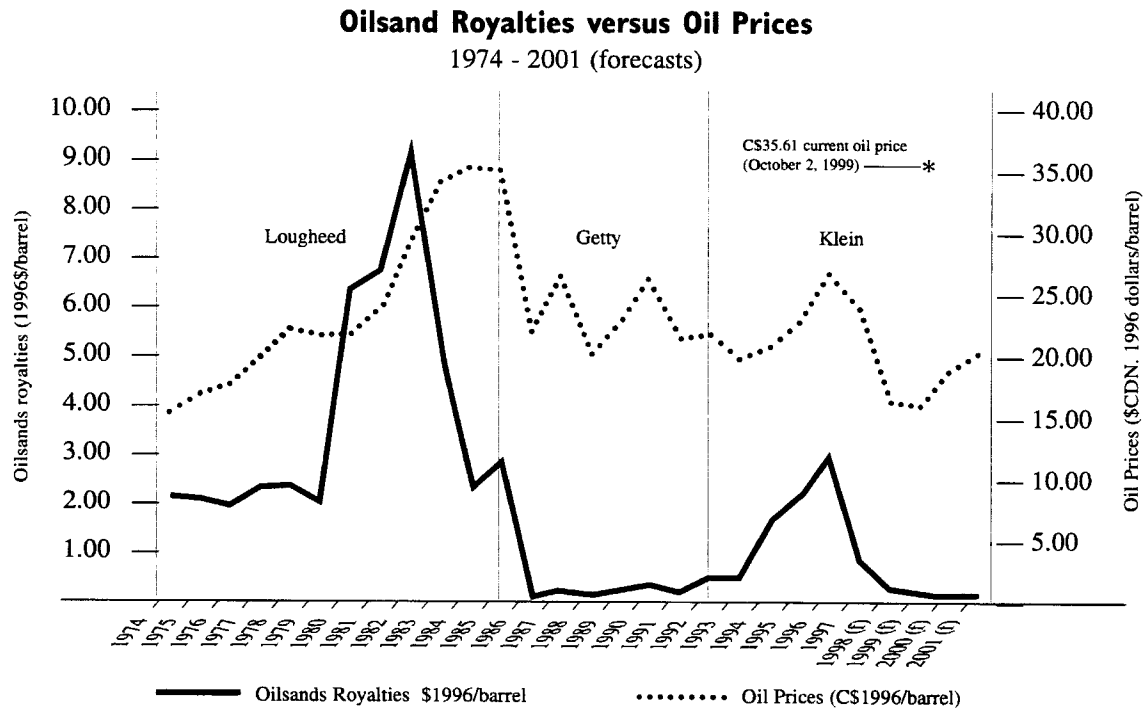
² Reserve life is the ratio of the volume of current total established reserves to current annual production.

The significant forecast decline in oilsands royalty revenues since 1996/97 can be attributed, in part, to the generic oilsands royalty regime introduced in 1995. The new royalty rate effectively reduced the rate of energy rent collection to a minimum 1% royalty payable on all production or 25% royalty payable on net project revenues, after the developer has recovered all project costs (including 100% of capital costs) including a return allowance for profit.

The key issue is the generous treatment of capital costs which allows 100% or full write-off against income rather than depreciating these capital investments over the life of the project, asset or oil reserve as is done in other sectors. This is more generous than the treatment of capital in the case of public utilities. It also appears to be inconsistent with the recent recommendations in the Mintz *"Business Taxation"* report of 1997 which recommended reducing maximum write-off on development costs in both mining and oil and gas and specifically, as it affects oilsands development, that "capital costs incurred in connection with new mines or major expansions of existing mines should not be immediately claimable in full against the income from the project."

The other significant factor is the actual royalty rate or the rate of rent collection. The British energy publication *Energy Economist* (1998) describes the new oilsands fiscal regime as "canny" and notes that the word "generic" is "a misnomer, even though the benefits are substantial....attractive, greatly reducing front-end burdens and overall risk" to industry. While there is little doubt that the oilsands development will provide considerable economic stimulus (jobs, construction, investment) to the province the fundamental question remains: *are Albertans receiving a return on their nonrenewable resources for current and future generations that is comparable to other nonrenewable energy-rich nations or jurisdictions?*

It should also be kept in mind that oilsands production has many other impacts on Alberta. The environmental impacts of oilsands developments, both those that have been foreseen and those that aren't, can still result in significant costs to local people and Albertans in general. Impacts on other industries like forestry, from increasing demands on the land base may also result in potential conflicts and ensuing costs. The social impacts of large developments in remote areas, such as disruption of traditional subsistence activities and social cohesion, are well documented in many areas of Canada's north. These types of potential impacts reinforce the need to ensure that the bounty of the oilsands, not only rewards the considerable efforts of petroleum producers, but also adequately accounts for the significant costs and risks borne by ordinary Albertans.



The financial impact of our current provincial policies

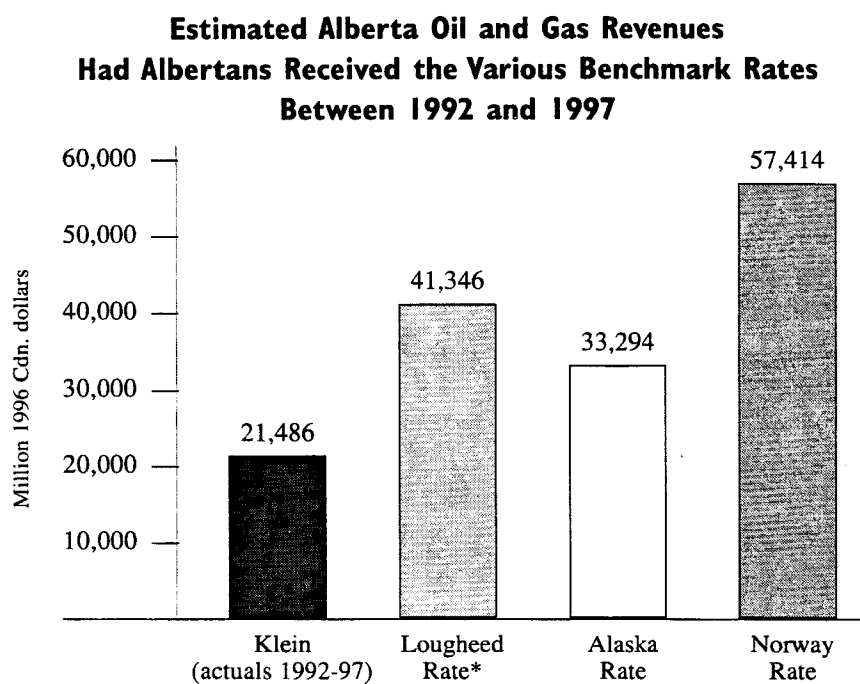
In terms of total petroleum production, Alberta actually produced 21% more oil, natural gas and byproducts by volume (barrels of oil equivalent) than Norway and 2.2 times more than Alaska between 1992 and 1997. Applying the international benchmark rates to Alberta's historical volume of production provided estimates of the additional oil and gas revenues that might have been realized under the Alaskan and Norwegian collection rates. Had Albertans received the average Alaska rate of energy rent collection, roughly \$2.0 billion per annum in additional revenues would have accrued to Alberta's coffers between 1992-1997. At the Norwegian rate, Albertans would have received roughly \$5.7 billion per annum in additional revenues over the same period.

Had the Klein administration continued to collect energy rents at the Lougheed rate, an additional \$3.78 billion per annum (in constant 1996 dollars) would have accrued to provincial coffers between 1992 and 1997.

To give these numbers perspective, consider that the Alberta Government spent an average \$3.96 billion per annum on health care and \$3.91 billion per annum

on the combined Education and Advanced Education & Career Development budgets between 1992/93 and 1997/98 (all figures are in constant 1996 Canadian dollars). Also, by 1996/97 total program spending by the Alberta Government (excluding debt servicing charges) had been reduced by \$3.38 billion compared with 1992/93.

When these comparisons are made, there is a very significant difference in what Albertans received from our oil and gas resources and what might had been collected if the Alberta government chose to collect resource rents at different rates.



* all figures, except the Lougheed Rate, include corporate income tax revenue estimates

Policy implications for the fiscal management and accountability of government.

The findings of this study have significant policy implications for fiscal management and accountability of government. The study points to the need for a regular assessment of energy rents and the share of these rents collected by government over time and in comparison with other international benchmarks. Currently, no such assessment exists. Just as investors receive annual reports from corporations that provide information on their return-on-investment, so should Albertans, as shareholders in natural resource assets, receive an annual account of the returns received from their development. This is simply part of good and accountable governance.

While preliminary, the benchmarking of Alberta against Norway and Alaska demonstrates the importance of such an exercise for informing public policy debate. The sheer magnitude of the differences in energy rent collection rates warrants greater scrutiny and accountability. Such accountability and benchmarking would create a level of awareness both within government and amongst Albertans that would lead to a more informed discussion of how Alberta's natural resources should be developed that achieves a balance between maximized fiscal returns to Albertans while ensuring a viable and internationally competitive energy industry.

The potential revenues that might have accrued to Alberta coffers had Alberta pursued rent collection at the Alaska and Norway benchmark rates could have made a significant difference to Alberta's revenue picture. Had such an analysis of energy rents been available, the nature of the budgetary debates since 1993 would most certainly have led to different outcomes. This study does not suggest that Alberta have the same rate of energy rent collection as other jurisdictions. Rather, Albertans need to understand their economy and fiscal environment relative to others in order to make more informed decisions. Moreover it is precisely this kind of information and knowledge that when revealed will empower decision makers to launch Alberta, as the Growth Summit articulated, "into a new period of economic and social development that is balanced, sustainable and aimed at creating the kind of province Albertans want in the year 2005."

Good and accountable governance necessitates an ongoing accounting of rent collection performance vis-à-vis other benchmarks. This study represents a starting point and an opportunity for all resource-based economies to conduct such analysis making it publicly available. Afterall, these are public resources or assets whose benefits from development belong to all Albertans. Albertans must continually ask of their government: *are we getting maximum returns from this valuable, nonrenewable resource?*

A. Introduction

Alberta is blessed with abundant oil and gas resources that contribute significantly to the quality of life of its citizens. The oil and gas industry generates employment for many Albertans, and will continue to do so as the development of the oil sands continues. This study questions whether Albertans' are receiving the maximum amount of resource rents for their oil and gas resources.

Why is this question critical? Because the collection of resource rents is directly linked to public services (e.g., health, education), as well as the government's need to collect revenue from other sources (e.g. via income taxes). In 1997-98 Albertans received \$3.78 billion in oil and gas resource revenues, a sum which constituted 21% of total government revenues. In many ways, resource rents allow Albertans a higher level of services and investment into the future than would be the case at current taxation levels. While the province needs to keep the industry financially viable, Albertans are entitled to the maximum possible return on their natural heritage assets as owners of these natural resources.

This study attempts to answer the following questions:

- How does Alberta compare with other international benchmarks, like Norway and Alaska?
- How does the collection performance of the current Alberta government compare with previous governments?
- What are the indications about Alberta's collection performance in the future?
- What is the financial impact of our current provincial policies on the collection of oil and gas revenues?
- What are the policy implications for the fiscal management and accountability of government?

What are the policy implications of our findings?

Resource rents measure the value of nature's free gift – oil and gas resources – to the people of Alberta. Rents can also be thought of as the difference between the international commodity price of oil and gas, less production costs (exploration, development/capital³ and extraction/operating costs) and a normal return on equity (profit). Ultimately, rents are a measure of the degree of scarcity of a resource.

The Alberta government collects resource rents through royalties, bonus bids, lease sales, fees, corporate income taxes and other tax instruments. In principle, the owners of these free gifts of nature – all Albertans – are entitled to 100% of the energy rents, assuming that the industry has covered its production costs and earned a normal rate of return on capital investment. In a perfect world, the entire resource rent could be collected through royalties, which are collected post-production and based on volume, price, and other operating conditions. In practice, governments' use a multitude of tax instruments to collect rents, and only a portion of rents are collected through royalties. Rents are collected prior to production through bonus bidding and Crown lease sales. Corporate income taxes, levied by both provincial and federal governments, also collect some rents based on taxable income. Besides collecting taxes, Alberta also provides the industry a royalty tax credit rebate.

There are reasons for allowing the industry to retain "residual", or "surplus" rents, meaning rents above a normal rate of return. Residual rents may be necessary to encourage investment in exploration and development of new resources. On the other hand, the oil and gas industry is highly concentrated, vertically integrated, and to a certain extent, able to set the terms for prices and rents. According to Copithorne, these industries can exercise "price leadership oligopoly", and "siphon the surplus (rents) out of the industry or out of the country by transferring natural resource products from their primary subsidiaries to their processing subsidiaries." (1979, p. 44-45). The highly concentrated oil and gas sector also has the capacity to capture monopoly profits arising from market power through artificially high production and labour costs.

³ Production costs are estimated from tables in the Canadian Association of Petroleum Producers' Statistical Handbook using Alberta exploration, development and operating costs for conventional crude oil, natural gas and gas-byproduct production as well as operating and capital expenditure data for oil sands production. In the estimation of rents we use a net price approach calculated from revenues (value of producer sales) less all costs, including exploration, operating, and capital/development cost, which are fully expensed at 100% of their annual value. Rents are estimated before royalties, bonuses and land acquisition (Crown lease sales) expenditures, and corporate income taxes which are considered separately in our analysis. Allowing for the 100% expensing of fixed capital expenditures (includes development costs) rather than using estimates of the opportunity cost of capital (i.e. depreciation and return to capital allowance) may be considered liberal and may tend to underestimate rents. Treating capital/development costs using depreciation charges on man-made capital plus a normal return to capital would be more in keeping with accounting conventions. We also estimate rents on this basis using the oil and gas rent estimates of Born (1992). The more liberal 100% expensing of fixed capital expenditures is how the new generic oil sands royalty regime introduced by the Alberta government in 1995 treats fixed capital investment by industry.

Governments must ultimately strike a balance between pursuing maximum rent collection, and allowing industry to retain a portion of the rents over and above a normal rate of return on their investments. The fundamental issue for Albertans is whether their government is realizing the maximum return on their inheritance, the free gift of nature's capital, while allowing the oil and gas industry to remain viable and healthy.

Methodological Considerations

Our analysis of energy rents covers the period 1972 to 1997. The government of Alberta's Public Accounts and budgets are used to assess energy resource rent collection performance of the government. We estimated rents generated from the production of all oil and natural gas resources, including conventional crude oil, synthetic/bitumen crude oil from oil sands, natural gas, and gas by-products (ethane, propane, pentane, butane, sulphur). Data for the international benchmark's, Norway and Alaska, came primarily from government sources.

We assumed that the costs and prices reported by industry are accurate and reflect competitive market conditions. The assumption of competitive market conditions is less tenable when there are conditions for monopoly profits, as discussed above. With imperfect competition, the size of the resource rent pie is potentially smaller, leaving less resource rents for Albertans. Under these conditions, surplus rents can be retained by the industry in the form of market access rents (monopoly profits, dividends that exceed international rates of return on capital) and possibly "gold-plated" (uncompetitively high) production costs (See Appendix 1 for more details).

Estimating resource rents and comparing the performance of governments in collecting these rents was no easy matter. In the absence of competitive markets, economic rents are not directly observable and require indirect measurement, such as comparing resource rents with other jurisdictions, or using historical comparisons (Copithorne, 1979). Given the considerable complexity involved in the analysis of rent collection, it should be kept in mind that this analysis is meant to provide a preliminary assessment of the current rent collection performance in Alberta. While our analysis cannot provide the final answer to the issue of rent collection in Alberta, our hope is to provide a useful starting point for a spirited public debate on the questions raised by our analysis.



B. The State of the Resource

Before accounting for resource rents and the public return on investment (e.g. in the form of royalties and taxes), we required an account of the physical state of oil and gas resources. More generally, an informed public discussion about oil and gas rents requires that the shareholders in nature's capital – every Albertan – have access to an annual report card on the current stock, rate of depletion, and reserve life of their nonrenewable energy resources. Information about the resource's sustainability, and the income generated are vital to informing the provincial government, and Albertans, of the scope of government revenues, and the public capacity to support spending on social programs.

Many petroleum companies report their reserve inventories in annual reports, and indirectly account for the reserve life of Alberta resources. Remarkably, the provincial government's public accounts and performance measures do not provide an annual account of the current inventory and reserve life of oil and gas, despite the economic importance of this resource⁴. In contrast, Norway publishes an annual resource account and analysis of the nation's energy and other natural resources.

Using government and CAPP data, we found that reserve life has been declining for both conventional crude oil and natural gas, the mainstay of government energy revenues, since 1972 (see Figure 1). In other words, production continues to outstrip replacement of reserves. In 1997 the reserve life (the ratio of reserves to current production) was 6.9 years for conventional crude oil and 10.5 years for natural gas. While these figures can change with new discoveries, extraction rates, and changes in the economic viability of the resource, reserve life is a key piece of information to consider in policy debates on the future of oil and gas, especially given the tremendous fiscal importance of this resource.

Breaking down the specific energy account components gives us a more complete picture of reserve life.

⁴ While the Alberta Energy Utility Board (EUB) does issue an annual report "Alberta's Energy Resources" these figures do not appear in either Alberta Energy's (the ministry) nor the Government's performance measurements (Measuring Up) nor does any discussion of the reserve life remaining as a key piece of information for Albertans, as shareholders in nature's capital.

Conventional Crude Oil

Once the mainstay of Alberta's energy industry, conventional crude oil has experienced a prolonged decline in reserves since production peaked in 1973 at 522 million barrels. By 1997, only 25%, or 2,278 billion barrels of the maximum recoverable reserves of 9,080 million barrels (1969) remained. At current rates of production (332 million barrels in 1997), the remaining conventional crude oil reserve will be exhausted in fewer than 7 years.⁵ While exploratory and development drilling continue to add to reserves, extending the reserve life of conventional crude oil, production continues to outstrip additions which results in a continuous decline in reserve life.

Oil Sands

Oil sands (both in situ and mining operations) are increasingly important to Alberta's energy sector. Currently, they amount to 38% of Alberta's crude oil production (207 million barrels) in 1997 (CAPP statistics). Alberta's oil sands are estimated to contain 300 billion barrels of recoverable bitumen crude oil, a source rivaling the reported oil reserves of Saudi Arabia (262 billion barrels).⁶ At 1997 rates of production the reserve life of Alberta's oil sands is roughly 1,500 years. The oil sands will undoubtedly become one of the most important strategic oil supplies in the world, and will become particularly important for the American market.

Natural Gas

Natural gas is the other significant asset in Alberta's nonrenewable resource inventory. Demand soars as the U.S. and Canada look for a cleaner, lower-carbon content fuel, and a means of reducing carbon dioxide emissions to meet the Kyoto emissions reduction objectives. Production of natural gas has more than doubled since 1987. Alberta's natural gas supply is roughly 1,400 billion cubic meters (down to roughly 73% of the maximum reserve of 1,900 billion cubic meters in 1984). At 1997 rates of natural gas production (133 billion cubic meters) Alberta's natural gas reserve life is roughly 10.5 years. The completion of the Alliance Pipeline will increase export capacity of Alberta's natural gas to

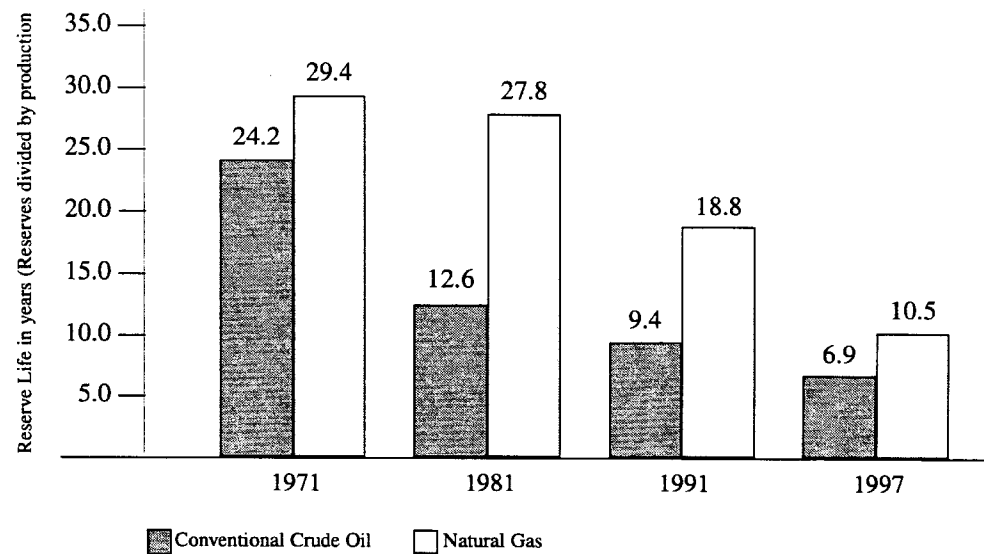
⁵ This assumes no increase in annual production nor any new additions to the recoverable reserves inventory.

⁶ CERA (Cambridge Energy Research)

the U.S. In 1997, gas sales to the U.S. accounted for 54% of Alberta's total natural gas sales. Just over 17% stayed in Alberta for heating, petrochemical feedstock, and electricity production.

Given the increased demand, and steady decline in reserve life for natural gas, we are left wondering about the prospects for clean energy security in Alberta – especially given the prospect of increased exports to the US with new pipeline capacity. Budget '99 forecasts that natural gas production will increase by 47% in 2001 (compared to 1996 levels). This figure has onerous implications for Alberta's environment and quality of life. Expanded demand and further depletion of natural gas reserves means a concomitant increase in exploration, drilling, and development activity in ecologically sensitive areas and in places near urban centres .

Figure 1: Years of Alberta Oil and Gas Production Remaining





C. International Benchmarks

Comparing Alberta with Alaska and Norway

Besides having accurate data on reserve life, an informed discussion on Alberta's record of rent collection requires international benchmarks. Norway and Alaska, resource-rich jurisdictions with similar resources and demographic situations to Alberta's, were compared over the 1992-1997 period. While international comparisons are challenging, especially given differences in oil and gas prices, production costs, and royalty and tax policies, sufficient information and careful analysis make such a comparison both possible, and useful.

Every attempt was made to ensure an 'apples-with-apples' comparison of energy revenue collection in each context. Each jurisdiction applies a slightly different suite of royalty and tax instruments to collect resource rents. For example, public accounts in Norway and Alaska include information on corporate income taxes paid by the petroleum industry, in addition to royalties and other fees. Alberta's public accounts do not provide data on the corporate income tax paid by Alberta's petroleum industry to either federal or provincial governments. However, in order to compare Alberta's rent performance with Norway and Alaska, we required an estimate of corporate income taxes paid by the petroleum industry.

In the absence of public data, we relied on industry sources. Rick Moss of Canadian Petroleum Perspectives (www.mossr.com/) compiles and analyses the financial statements of Canada's petroleum industry using data from roughly 110 firms. This data set provided statistics on "current taxes" paid by the industry (including corporate income tax, federal and provincial), as well as total production of oil and gas (measured in barrels of oil equivalent (boe)) between 1992 and 1997. This data allowed us to estimate average corporate income taxes paid per unit of oil and gas produced. While we could have split the federal versus provincial portion of corporate income taxes paid, we chose to consider both federal and provincial income taxes together.⁷ The federal corporate income tax rate is 28% of taxable income, plus a 4% surtax. The Alberta corporate income tax rate is 15.5% of taxable income.

Using the CPP data we estimated that the Canadian petroleum industry paid on average \$0.30 per boe produced in federal and provincial corporate income taxes between 1992 and 1997. Applying this figure (\$0.30/boe) to Alberta's actual production figures yields an estimated \$433 million, on average between 1992 and 1997, paid by the Alberta petroleum industry. Using the ratio of federal to provincial income tax rates would mean that roughly \$290 million (\$0.20/boe) in corporate income taxes accrued to the federal government while \$143 million (\$0.10/boe) accrued to the provincial government (see Table 16, Appendix 2). This means that a portion of our estimate of Alberta's share of oil and gas rents is actually accrued to the federal government. Given the nature of this exercise, and the lack of public data, we accept this complication. Most importantly, this analysis points to the need for full disclosure of corporate income taxes paid by the petroleum industry in Alberta's public accounts in order to conduct future oil and gas rent collection analysis.

⁷ The federal corporate income tax rate is 28% of taxable income plus a 4% surtax. The Alberta corporate income tax rate is 15.5% of taxable income. Thus 67% of the estimated \$433 million in corporate income taxes or \$290 million went to the federal government while 33% or \$142 million went to the Alberta government.

Our comparisons of Alberta with Norway and Alaska reveal the following results (see Table 1, Figure 2 and Figure 3). The differences in government revenues collected for every unit of oil, gas and byproducts produced are significant. For the benchmark period 1992-1997 the Klein government collected an average \$2.41/boe (including federal and provincial income taxes), while Alaska collected \$3.74/boe and Norway collected \$6.41/boe, all in constant 1996 Canadian dollars. These differences in revenue collection rates are significant, amounting to billions of dollars, when applied to the total volumes of Alberta oil and gas production. Details on Alaska and Norway follow in the next sections."

Figure 2: International Benchmarks: Government Oil & Gas Revenues per boe production

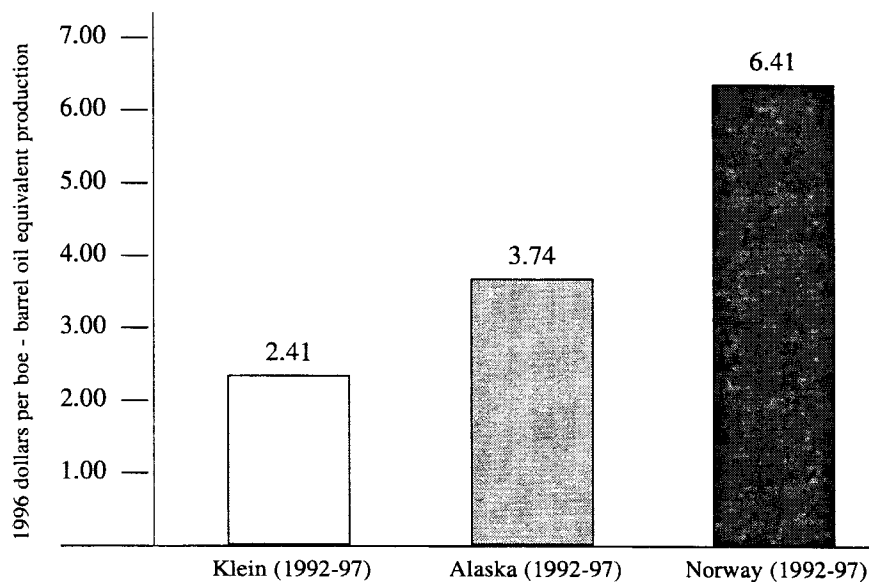
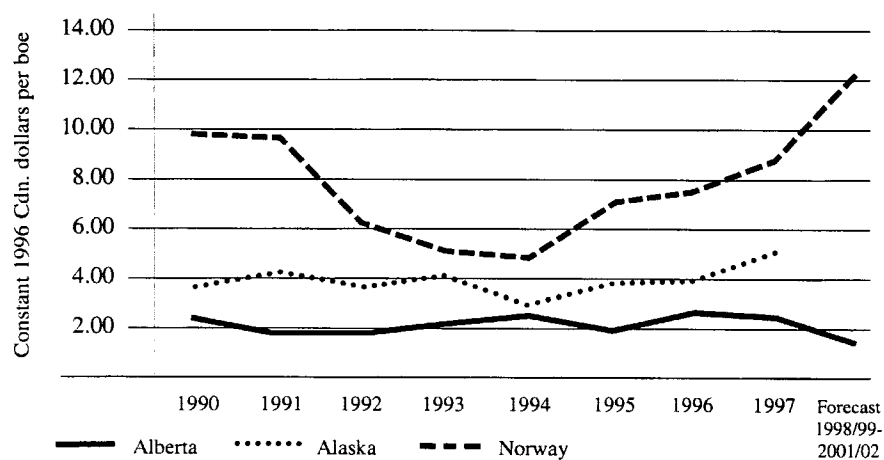


Figure 3: Government Petroleum Revenues per boe: Alberta, Alaska and Norway (Cdn\$)



Sources: Alberta Government; Norwegian Ministry of Petroleum and Energy; Department of Revenue, State of Alaska; CAPP

Table 1: Petro-wealth Comparisons: Alberta, Alaska and Norway (1992-1997)

	<u>1992 - 1997:</u>	<u>Alberta</u>	<u>Alaska</u>	<u>Norway</u>
<i>Government Petroleum Revenues</i>				
(Cdn 1996\$ millions, total)		21,484	14,767	47,440
(Cdn 1996\$ millions, average per annum)		3,581	2,461	7,907
<i>Oil and Gas Production Statistics (ave. per annum)</i>				
Oil (million barrels)		514	550	962
Natural Gas (billion mcf)		4,135	471	1,091
Total Oil, Natural Gas and Byproducts (b.o.e.)		1,447	663	1,201
<i>Government Revenues per unit production</i>				
per oil equivalent of production (Cdn 1996\$/m3 boe), average 1992-97		2.41	3.74	6.41
Forecast 1998/99 - 2001/02 (1996 Cdn\$/boe) (Alberta)		1.19	n.a.	n.a.
<i>Total Production Costs per barrel oil equivalent</i>				
(exploration, development/capital, operating costs), 1996				
Cdn\$ per b.o.e.		10.65	n.a.	10.08 - 15.85
US\$ per b.o.e.		7.46	n.a.	7.00 - 11.00
<i>Operating Costs, 1997</i>				
Cdn\$ per b.o.e. total industry		4.19	n.a.	5.76 - 7.20
US\$ per b.o.e. total industry		2.90	n.a.	4.00 - 5.00
Cdn\$ per barrel conventional crude oil		10.06	n.a.	
US\$ per barrel conventional crude oil		6.98	n.a.	4.00 - 5.00
Cdn\$ per barrel of oilsands crude oil		8.92	n.a.	5.76 - 7.20
US\$ per barrel oilsands crude oil		6.19	n.a.	4.00 - 5.00
<i>Petroleum Fund Savings</i>				
		<i>“Alberta’s Heritage Fund”</i>	<i>“Alaska’s Permanent Fund”</i>	<i>“Norway’s Petroleum Fund”</i>
(\$Cdn billions, 1997 balance		12.0	40.0*	29.43
* Alaska’s Fund as of April 1999				

Notes: 1. All dollar figures are in current dollars.

2. Government revenue figures include royalties, bonus fees, corporate income taxes (federal, provincial/state), and other taxes and fees levied.

Sources:

Canadian Association of Petroleum Producers, Statistical Handbook

Alberta Government, Public Accounts, various Budgets

Alaska Dept. of Natural Resources, Alaska Dept. of Revenue

Norwegian Ministry of Petroleum and Energy, Ministry of Finance, and Statistics Norway

CERA (Cambridge Energy Research Assoc.)

C.1 Norway

Similar energy resource endowments and demographics made the Norwegian case a productive point of comparison.⁸ Some differences should be noted:

- Norway's average annual production of crude oil is roughly two times that of Alberta. From 1992-97 Norway produced an average 962 million barrels per annum compared with Alberta's 514 million barrels per annum.
- Alberta produced over three times as much marketable natural gas as Norway. Between 1992 and 1997 Alberta produced 4.1 trillion mcf (thousand cubic feet) per annum, compared with Norway's 1.1 trillion mcf (average of 30.9 million m3 oe).
- Comparing total volume of oil, gas and byproducts, Alberta produced 21% more volume (1.45 billion boe) than Norway (1.2 billion boe) between 1992-1997.
- Norway's 4.3 million population compares with Alberta's 2.8 million.
- Norway's Troll gas field, which began production October 1, 1996, has exploitable reserves of an estimated 1.3 trillion cubic meters (1% of the world's known gas reserves and Europe's largest offshore gas field); Alberta's natural gas reserves as of 1997 are estimated at 1.39 trillion cubic meters (CAPP, 1998).

Norwegian revenues from petroleum resources are generated through two major sources:

1. The tax and royalty system;
2. The state's direct financial interest (SDFI) in the petroleum sector - including dividends and the rise in asset value for the state's holdings in Statoil (the national oil company) (Norwegian Ministry of Petroleum and Energy, 1998. odin.dep.no/html/nofavalt/depter/oed/publ/fakata/kap).⁹

The most important taxes on petroleum operations include the royalty on oil production,¹⁰ a special profit (rent) tax, corporate income taxes, as well as a carbon tax and area fees on all production. Based on petroleum revenue statistics between 1992 and 1997, an average \$6.41/boe was collected. This figure can be broken down into its various tax components as follows:

⁸ Data for Norway includes the period 1985 to 1997 and comes from the Norwegian Ministry of Petroleum and Energy annual reports, Ministry of Finance, and Statistics Norway. Respected Norwegian energy economist, Oystein Noreng's analysis of resource rents in the case of Norway and the UK (The Concept of Economic Resource Rent and its Application in UK and Norwegian Petroleum Taxation) provides excellent insights into energy rents.

⁹ Norway's government revenue figures include royalties, corporate taxes, special profit taxes, area fees, carbon taxes, net SDFI (state's direct financial interest) cash flow and dividends paid by Statoil, Norway's state-owned petroleum company.

¹⁰ No royalty is charged on natural gas.

Special Profit (Rent) Tax	\$1.66 (26%)
SDFI (State's Direct Financial Interest; Statoil)	\$1.60 (25%)
Royalties	\$1.31 (20%)
Corporate Income Taxes	\$1.30 (20%)
Carbon Tax	\$0.46 (7%)
Area Fee ¹¹	\$0.11 (2%)
Total	\$6.41/boe

The ordinary corporate tax rate in Norway is 28% on land and offshore production profits, plus a 50% tax levied on production situations of extraordinary profitability. Calculation of taxable income for both ordinary and special taxes is based on the linear depreciation of investments over six years from the date of investment. The state's direct financial interest (SDFI) in petroleum operations was established in 1985 by dividing Statoil's interest in offshore fields into an equity share for Statoil and a direct interest for the state. The state now has a direct interest in most offshore oil and gas fields.¹²

Key points of our comparative analysis can be summarised as follows:

- Norwegians received roughly 266%, or 2.7 times more for every unit (boe) of oil and gas produced.
- Norway collected an average \$6.41/boe produced from their energy industry while Alberta collected an average \$2.41/boe over the same time period.¹³
- Norwegians received roughly \$4.00/boe more in revenues for every barrel equivalent of oil and natural gas produced.
- Had Albertans received the Norwegian rate of energy revenue collection, an additional \$5.69 billion per annum would have flowed into provincial revenue coffers between 1992-1997 (based on actual volumes of oil and gas produced).
- Even though Alberta produced roughly 21% more oil and gas, Norwegians received an average \$7.9 billion per annum in oil and gas revenues, while Albertans received \$3.58 billion per annum between 1992 and 1997 (see Table 10 Appendix 2 for Norwegian data).

.....continued next page

¹¹ The area fee is NOK 4,000 per square metre during the exploration period, NOK 5,000 per square metre annually for an extension of this period. Once the exploration period has expired, the annual fee increases with time and varies from NOK 7,500 to NOK 61,000 per square kilometre annually over the subsequent decade. Thereafter the fee is NOK 121,500 per square kilometre annual. Carbon tax is levied at a rate of NOK 0.85 per thousand cubic metres of gas burnt or directly released and per litre of oil burnt. Note: 1 US\$= 7.17 NOK (kroner) in 1997.

¹² According to the SDFI arrangement, the state pays a share of all investment and operating costs in a project corresponding to the state's direct interest. The state also receives a corresponding proportion of production and other revenues. Statoil is responsible for operative and financial management of the state's direct interests.

¹³ In order to make the Alberta figures comparable with both Norway and Alaska required the inclusion of corporate income taxes paid by the Alberta energy industry to both federal and provincial (Alberta) governments. Unfortunately, Alberta's public accounts do not account for corporate income taxes paid by the petroleum industry. Instead, federal and provincial corporate income taxes had to be estimated based on industry financial statistics reported by Canadian Petroleum Perspectives. Based on financial data from an annual survey of some 110 Canadian petroleum companies, the CPP figures reveal that "current taxes" (includes federal and provincial corporate income taxes and municipal taxes) averaged roughly \$0.30 per barrel oil equivalent (boe) of oil and gas production between 1992 and 1997. Applying this figure to the average volume (boe) produced in Alberta would equate to an estimated \$433 million per annum (1996 constant dollars) paid by Alberta's petroleum industry between 1992 and 1997.

- The Norwegian Petroleum Fund had a 1997 balance of \$29.4 billion. In 1997 an estimated 41 billion kroner (\$8 billion Cdn.) was added to the fund from petroleum activities, and the Fund is projected to grow to \$270 billion kroner (\$54 billion Cdn.) by the year 2000.

What about the comparison of future rents? The forecast for the year 2000 for petroleum revenues is an impressive 100 billion kroner (\$20.5 billion) or an estimated \$12.42/boe. In stark contrast, Alberta's forecast for petroleum revenues in the year 2000/2001 is expected to drop to its lowest rate in decades – \$1.19/boe (based on Budget '99 figures). The sharp expected increase in Norwegian energy revenues is attributable to higher expected petroleum industry tax revenues, and sharply increasing operative revenues from the State's Direct Financial Interest in the petroleum activities of Statoil.

How can we account for the gap of \$4.00/boe between Norway's rate of revenue collection and Alberta's rate? Are Norwegians more aggressive at energy rent collection or are there more rents available for collection? The following factors stand out as critical:

- There are critical differences in corporate income taxes actually received by government. Alberta energy companies pay roughly \$0.30/boe in corporate income taxes (both federal and provincial), while the Norwegian industry pays \$1.30/boe.
- Norway levies a special profits (rent) tax and has a financial interest termed "State Direct Financial Interest (SDFI)" through the national energy company, Statoil. The special profits tax yielded an average \$1.66/boe for Norway while the SDFI returns from Statoil operations yielded an additional \$1.60/boe of production between 1992 and 1997; together these total \$3.22/boe.
- Norway has a carbon tax that earns on average \$0.46/boe.
- Norway has traditionally been aggressive in resource rent collection policies with the Norwegian Parliament explicitly setting out to collect 70% of available energy rents (Noreng 1999). By contrast, Alberta's new generic oil sands royalty regime expects to collect only 25% of net revenues, and only after covering all production expenses, 100% of capital, plus a normal return on capital.

Can the gap be explained by differences in prices and production costs between Norway and Alberta? "The Economist" recently reported that total production costs for North Sea oil are US\$11.00 per barrel.¹⁴ North American production costs were also reported at \$11.00 per barrel, with no distinction made between

⁸ According to the British publication *Energy Economist* (1998) current North Sea operating costs are roughly US\$ 4-5 a barrel or C\$6.00-7.50 per barrel (this would apply to both UK and Norwegian production in the North Sea). In personal conversation with Noreng Øystein, one of Norway's leading energy economists, he noted that average finding (exploration) costs are about US\$ 1.00 per barrel, development costs roughly \$US 5.00 per barrel and lifting (operating/production) costs range from US\$1.00 to \$4.00 per barrel.

U.S. and Canadian costs. Although there are most certainly variations in production costs for both cases, at least on an aggregate level it appears that production in Norway and Alberta are at least roughly comparable. In this light, it seems unlikely that the \$4.00/b.o.e. difference between Alberta and Norway is entirely due to differences in production costs. In terms of the price of oil, the average price of North Sea oil between 1992 and 1997 was roughly 15% higher than Alberta wellhead price. North Sea oil averaged US \$18.28 per barrel compared to \$US 15.95 for Alberta.

Without more detailed information on Norway, the discrepancies in revenue collection cannot be accounted for in an absolute sense. While international rent comparisons are complicated, the Norway benchmark suggests that the government is receiving significantly higher returns on their oil and gas assets. Moreover, many of the same transnational corporations operating in Norway are apparently willing to pay higher royalties and taxes than in Alberta for the right to develop these free gifts of nature.

C.2 Alaska

We also compared Alaska with Alberta. Again, certain differences in the two cases should be noted:

- Alaska produced slightly more conventional crude oil than Alberta. Between 1992-97 Alaska's average annual production was 550 million barrels compared with Alberta's 514 million barrels.
- Marketable natural gas production was significantly lower in Alaska (471 billion mcf) than in Alberta (4.2 trillion mcf).
- In terms of total production of oil, gas and gas byproducts, Alberta produced 2.2 times more volume per annum (1.45 billion boe) than Alaska (663 million boe) between 1992 and 1997.

Alaska's petroleum revenues have three major sources:

- Oil and gas royalties (in-value and in-kind);
- Bonuses and lease fees;
- Corporate income taxes.

Given that much of Alaska's natural gas is not marketed, only relatively minor revenues come from gas royalties.

Key points of our comparative analysis between Alaska and Alberta can be summarised as follows:

- Alaska received roughly 155%, or 1.6 times more for every unit (boe) of oil and gas produced.
- Between 1992 and 1997, the Alaska government collected an average \$2.5 billion Cdn. per annum.
- In terms of dollars per barrel, Alaska collected an average \$3.74/boe of production compared to Alberta's average \$2.41/boe.
- Alaskans received \$1.33 more / boe produced.
- Had Albertans received the Alaska rate of revenue collection, an addition \$1.97 billion per annum would have accrued to provincial revenue coffers between 1992 and 1997 (based on actual production volumes of oil and gas).
- Alaskans have a healthy oil and gas "Permanent Fund". As of April 19, 1999 the Alaska Permanent Fund contained assets of US\$26.3 billion (almost Cdn \$40 billion).¹⁵ In September 1998 roughly 564,000 Alaskans were eligible to receive a record dividend of US\$ 1,540.88 each (or Cdn \$2,210 per citizen). The \$40 billion (Cdn.) saved in Alaska's petroleum fund is even more impressive considering that the sum total of petroleum revenues collected between 1977 and 1997 by the Alaska government totaled US \$42.6 billion (Cdn. \$54.0 billion). In contrast, Alberta's oil and gas revenues between 1977-1997 have totaled \$65.3 billion (Cdn.) with only \$12.0 billion saved in the Alberta Heritage Trust Fund and paying no dividend.

In attempting to account for the differences between Alaska and Alberta, we found that conventional crude oil prices were actually lower in the case of Alaska. Between 1992 and 1997 average Alaska wellhead prices were only 76% of Alberta's comparable price. Alaskan crude oil earned US\$12.15 per barrel (current dollars), compared to Alberta's wellhead average price of US\$15.95 per barrel. We did not have Alaska production costs for comparison.

¹⁵ <http://www.ssb.no/www-open/english/yearbook/tab/t1511001.shtml>

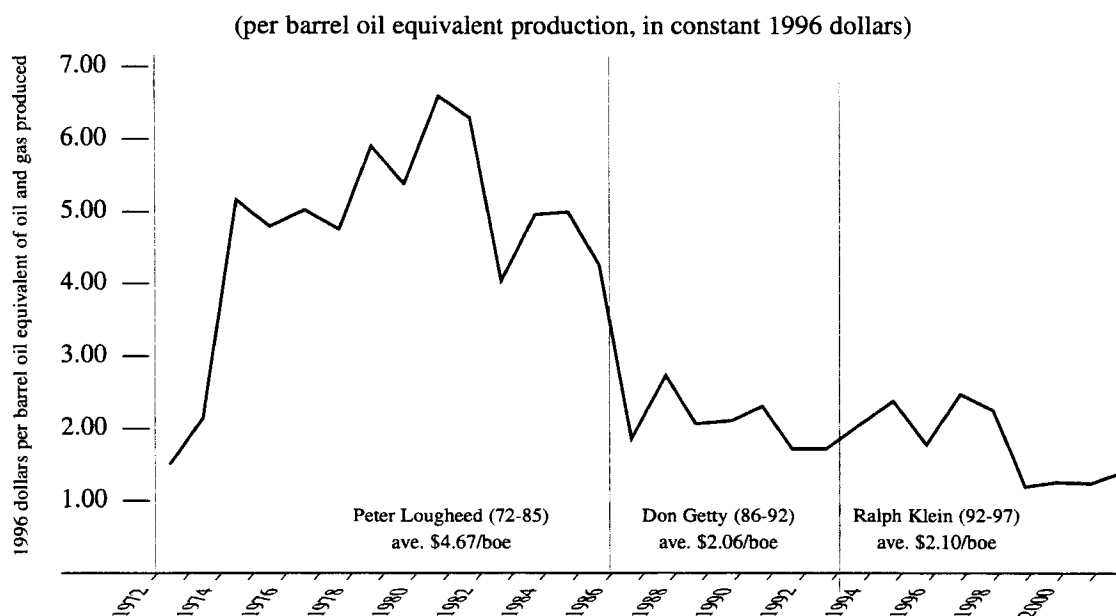
D. Alberta's Historical Rent Collection Record

Another way to assess Alberta's current energy revenue collection is to examine historical efforts by successive Alberta governments. How do the performances of the Lougheed, Getty and Klein governments compare?

To answer this question, we examined energy revenues collected from 1972 to 1997. Factors we included in the comparison included the following: oil and gas royalties, bonuses and sales of Crown leases, net of royalty tax credits on a per unit (boe)¹⁶ basis for conventional crude oil, bitumen/synthetic crude oil, natural gas, and gas-by-products. Corporate income tax revenue estimates are excluded from this historical analysis given the lack of publicly available information on provincial corporate income tax paid by Alberta's petroleum industry.

The results of our analysis are revealed in Tables 2 and 3 and Figure 4. Figure 4 also shows projected oil and gas revenues under the Klein administration extending to 2001/2002 based on Budget '99 forecast figures.

Figure 4: Alberta Government Oil & Gas Revenues



Source: Alberta Government Public Accounts and Budgets, and CAPP statistics

¹⁶

Throughout the document we use b.o.e. (barrel oil equivalent) units of production for all oil and gas products produced. CAPP (Canadian Association of Petroleum Producers) provides production statistics in cubic meters of oil equivalent which are converted to barrels of oil equivalent by the standard conversion of roughly 1 m3 oe = 6.29 barrels of oil equivalent.

Table 2: Alberta Government Oil and Gas Revenue Collection Performance

Fiscal Year	Calendar Year (1996 constant dollars)	Oil & Gas Revenues (\$ millions)	Oil, Gas and Byproducts Production million boe	Oil & Gas Revenues per boe produced 1996\$/boe
72/73	1972	1,345	921	1.46
73/74	1973	2,179	1,040	2.10
74/75	1974	5,254	1,028	5.11
75/76	1975	4,585	962	4.77
76/77	1976	4,580	921	4.97
77/78	1977	4,433	940	4.72
78/79	1978	5,416	925	5.86
79/80	1979	5,526	1,029	5.37
80/81	1980	6,474	988	6.55
81/82	1981	5,923	943	6.28
82/83	1982	3,779	940	4.02
83/84	1983	4,620	933	4.95
84/85	1984	4,976	1,000	4.98
85/86	1985	4,470	1,056	4.23
86/87	1986	1,836	995	1.84
87/88	1987	2,891	1,055	2.74
88/89	1988	2,384	1,166	2.04
89/90	1989	2,454	1,166	2.10
90/91	1990	2,724	1,197	2.28
91/92	1991	2,036	1,204	1.69
92/93	1992	2,187	1,283	1.70
93/94	1993	2,853	1,393	2.05
94/95	1994	3,398	1,444	2.35
95/96	1995	2,761	1,537	1.80
96/97	1996	3,884	1,580	2.46
97/98	1997	3,575	1,617	2.21
Forecast 98/99	1998	2,052	1,770	1.16
Forecast 99/00	1999	2,169	1,849	1.17
Forecast 00/01	2000	2,219	1,915	1.16
Forecast 01/02	2001	2,535	2,010	1.26
Averages				
Lougheed (1972-1985)		4,540	973	4.67
Getty (1986-1992)		2,359	1,152	2.06
Klein (1992-1997)		3,109	1,476	2.10
Klein (forecast 1998-2001)		2,244	1,886	1.19

Notes: boe (barrel oil equivalent) units of production

Sources: Canadian Association of Petroleum Producers and Government of Alberta

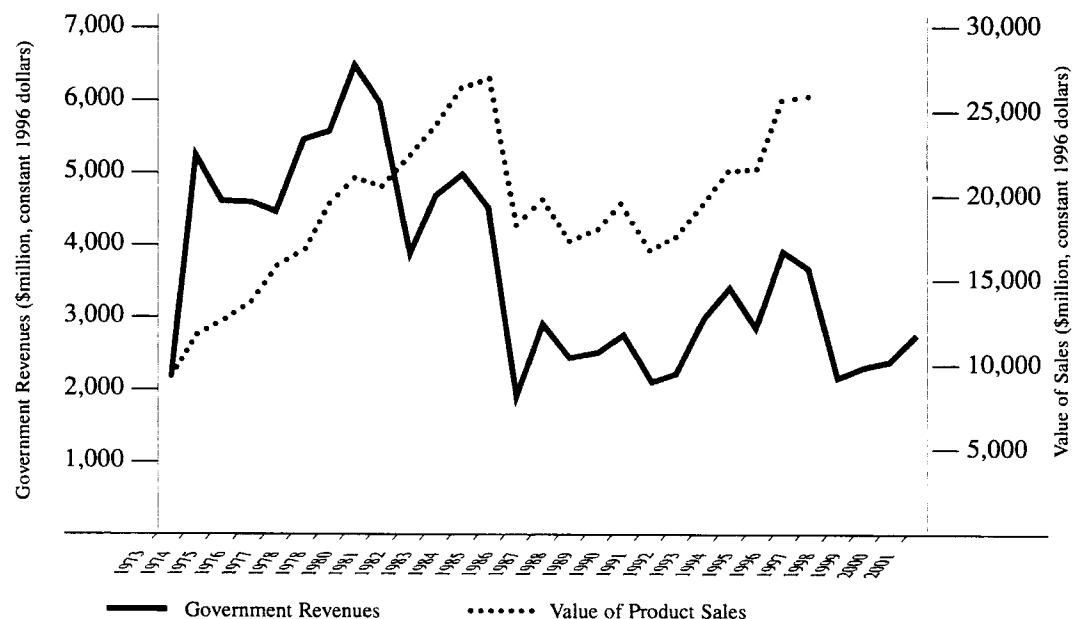
Table 3: Royalties per boe and Natural Gas in constant 1996\$

Year	conventional crude oil	oilsands bitumen/synthetic crude oil	natural gas & byproducts
1974	5.30	2.23	5.14
1975	5.50	2.17	4.50
1976	6.12	2.00	4.54
1977	6.91	2.41	3.62
1978	8.60	2.39	4.54
1979	7.33	2.08	4.48
1980	7.05	6.36	5.02
1981	7.87	6.73	4.69
1982	7.89	9.12	3.92
1983	8.95	5.19	3.52
1984	8.29	2.36	3.70
1985	7.36	2.90	3.04
1986	3.52	0.14	2.31
1987	4.53	0.25	2.00
1988	3.11	0.19	1.75
1989	3.78	0.27	1.58
1990	4.25	0.33	1.57
1991	3.34	0.23	1.28
1992	3.22	0.52	1.40
1993	2.39	0.52	1.65
1994	3.34	1.63	1.38
1995	3.09	2.11	1.03
1996	4.07	2.93	1.24
1997	2.72	0.82	1.40
1998 (f)	1.20	0.26	1.16
1999 (f)	1.00	0.18	1.26
2000 (f)	1.17	0.13	1.18
2001 (f)	1.16	0.08	1.26
Lougheed (1972-85)	7.26	3.83	4.23
Getty (1986-92)	3.68	0.28	1.70
Klein (1992-97)	3.14	1.42	1.35
Klein (1998-2001)	1.13	0.16	1.21
average 92-97	3.14	1.42	1.35
average 1998/99-2001/02	1.13	0.16	1.21
% change between 2 periods	-64%	-89%	-10%

Our historical analysis revealed the following data:

- Between 1972 and 1985 the Lougheed government collected more than twice as much oil and gas revenues per boe than either Don Getty or Ralph Klein.
- The Lougheed government collected an average \$2.57/boe more than the Klein government, and \$2.61/boe more than the Getty administration.
- The Lougheed government collected an average \$4.8 billion per annum or an average \$4.67/boe.
- The Getty government (1986/87-1992/93) averaged \$2.4 billion per annum or \$2.06/boe.
- The Klein government (1992/93-1997/98) averaged \$3.1 billion per annum or \$2.10/boe.¹⁷
- Budget '99 forecasts a significant drop in oil and gas revenues for 1998/99 to 2001/02 to an average historical low of \$1.19/boe or \$2.2 billion per annum.¹⁸

Figure 5: Government Oil and Gas Revenues vs. Value of Industry Sales



Source: CAPP and Alberta Government

¹⁷ In terms of dollar of government revenues collected per dollar of oil and gas industry (producer) sales Lougheed's average rent collection record from 1971-1985 average roughly \$0.27 per dollar of sales compared to Getty at \$0.13 per dollar sales and Klein at \$0.14 per dollar of sales.

¹⁸ The forecasts for 1998/99 to 2001/2002 uses a projected GDP implicit price index (1996=100) starting with 1997 actual index forecast to increase at a rate of 1.5% per annum (similar to the projected CPI index percent change in Budget '99 (Fiscal Plan, p. 44)

Figure 6: Crude Oil (Alberta Wellhead) and Natural Gas Prices

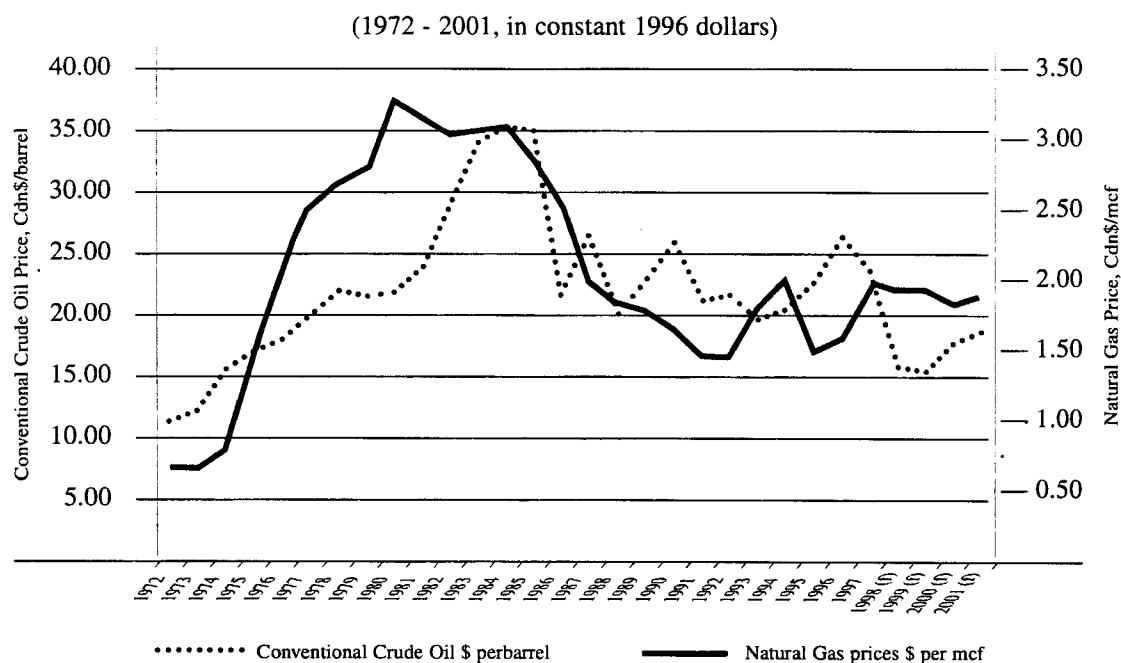
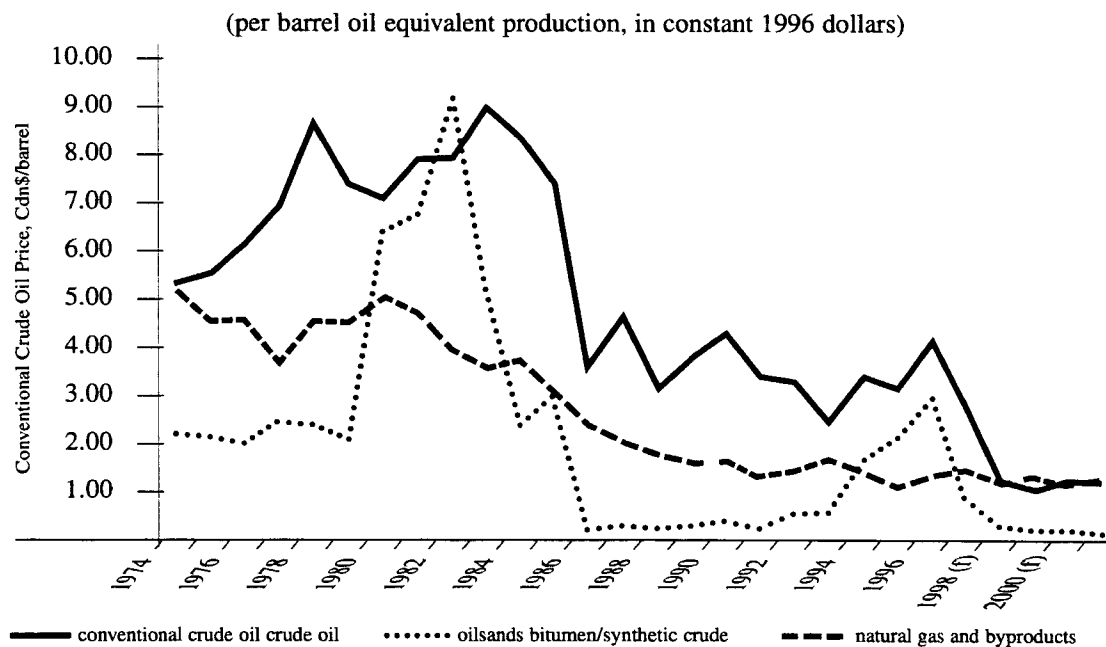


Figure 7: Royalties for Conventional Crude Oil, Oilsands (Bitumen/Synthetic oil), Natural Gas and Gas Byproducts

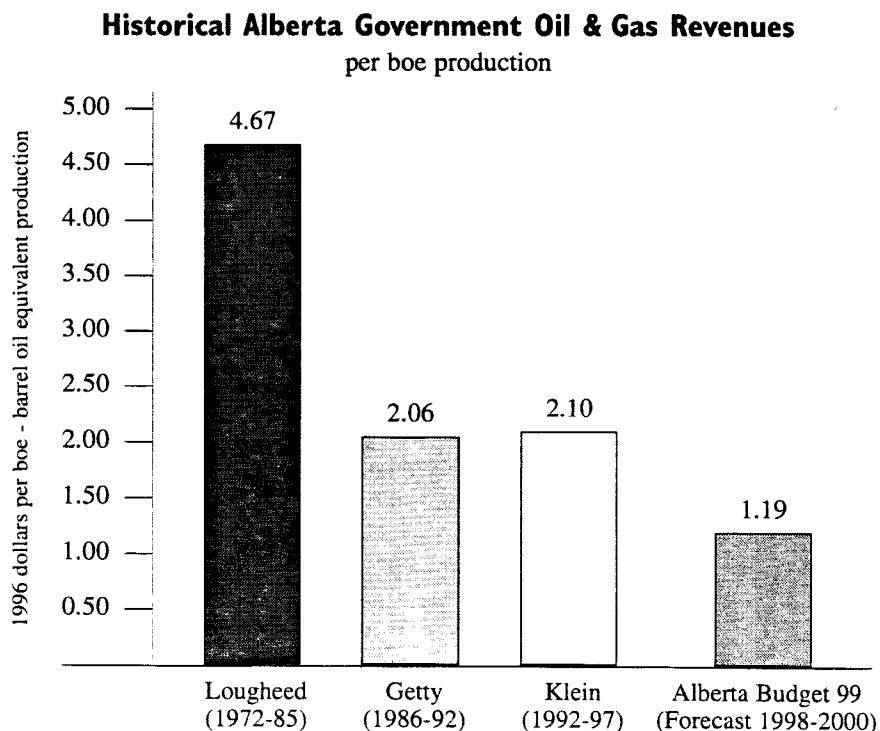


The historical analysis is particularly revealing when we examine the evolving revenue collection for conventional crude oil, bitumen/synthetic crude oil from oil sands, and natural gas and by-products. Figures 5, 6 and 7 show Alberta's history since 1972 with projections to 2001. Several points are particularly significant:

- There was a dramatic fall in conventional crude oil and oil sands royalties following the 1986 world oil price collapse; royalty rates have not recovered since 1986.
- Royalties for natural gas per unit of production have fallen steadily over time.
- There was a short-lived, but significant rise in oil sands royalties between 1995 and 1997. (see Section G for explanation)

A comparison of royalty rates under the Lougheed and Klein governments reveals a dramatic contrast in the amount of royalties collected:

- The Lougheed administration collected an average \$7.26 per barrel of conventional crude oil produced, \$3.83 per barrel on synthetic/bitumen crude oil from oil sands, and \$4.23/boe on natural gas and by-products.
- In stark contrast, the Klein administration (between 1992/93 and 1997/98) averaged \$3.14 per barrel on conventional crude oil, \$1.44 per barrel on oil sands production and \$1.37/boe on natural gas/by-products.



Of particular note is that royalties are projected in Budget 99 to decline dramatically between 1998-99 and 2001-02 compared to the study period 1992-93 to 1997-98. While part of this decline is due to the original lower oil price forecast, the government's figures suggest that the expected decline in royalties is greater than the forecast decline in prices. For example, while crude oil prices are forecast to be only 25% lower between 1999-2000 and 2001-02 than between 1992-93 and 1997-98, total oil royalties per barrel are expected to be 62% lower, with oilsands royalties expected to be 88% lower, over the same period. Natural gas and byproduct prices are expected to be 10% higher between 1999-2000 and 2001-02 yet royalties per unit of production of these products is forecast to be 7% lower compared to the 1992-1998 period. We might have expected a closer relationship between changes in price and royalties. The reason for these rather large discrepancies is of concern. Part of the discrepancy in the case of crude oil is presumably due to the effects of the generic oilsands royalty regime.

How do we account for the significant decrease in energy revenue collection per unit of production since the Lougheed era? We would expect that discrepancies in market conditions might have resulted in smaller energy rents available for governments to collect. Certainly, Lougheed's era enjoyed high energy prices and high energy rents, with relatively lower real production costs for conventional oil (but higher oilsands costs) than in later years. But despite this advantage, the Lougheed government was still more aggressive in collecting energy rents. To verify this conclusion we examined the historical changes in industry production costs and government oil and gas revenues¹⁹ as a share of the market value of oil and gas sales (see Figure 7). A "residual" value, the difference between the value of producer sales and production cost and government revenues, was also estimated. This residual could constitute either industry profits, retained earnings, dividends to investors, the Alberta royalty tax credit to industry, or federal and provincial corporate income taxes paid.

For every dollar of oil and gas producer sales, the Lougheed government collected on average \$0.26 per dollar in royalties and other oil and gas-related revenues (including bonuses, sale of Crown leases, net of royalty tax credits). This performance varied across time. From 1972 to 1981 the Lougheed administration collected an average \$0.32 per dollar value of producer sales while industry costs averaged \$0.48 of value of sales. The remaining residual averaged \$0.20 per dollar sales. Between 1982 and 1985, during robust oil and gas prices, Alberta government revenues dropped to \$0.19 per dollar value of sales, while industry production costs were also lower at \$0.39/dollar sales, leaving a significant residual of \$0.43/dollar sales, some of which was captured by the federal government. As oil prices collapsed in 1986, the new Getty government's share

¹⁹ Industry production costs include exploration, development/capital and operating; government oil and gas nonrenewable resource revenues include royalties, bonuses, sales of Crown leases, net of royalty tax credits but excluding federal/provincial corporate income taxes which are in a surplus rent (market access rent) or profit taxes.

of the value of producer sales plummeted to \$0.10/dollar sales while industry costs soared to \$0.63/dollar sales. The residual portion was \$0.27/dollar sales.

The dramatic decline in government revenues as a share of industry sales in 1986 was due primarily to the Getty government's combination of reduced royalties, royalty holidays and tax credits to help alleviate the industry's pain of world oil and gas price collapse. What is critical to emphasize is that since 1986, government resource revenues have languished at \$0.14/dollar producer sales values, industry costs have remained high at \$0.69/dollar of sales, while residual values were squeezed to \$0.17/dollar sales.

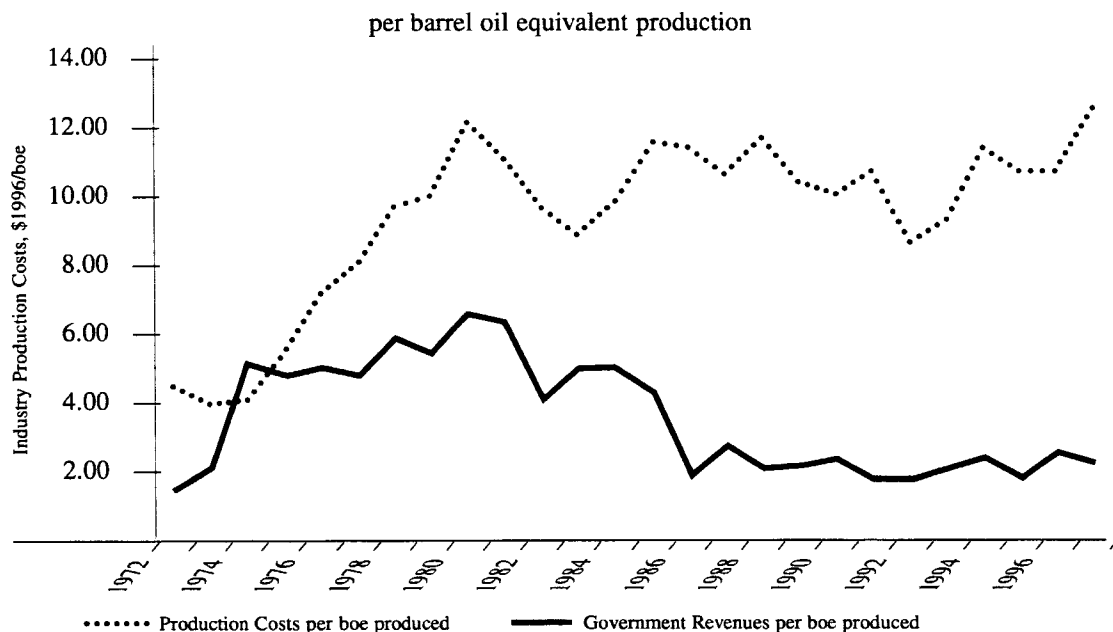
The Klein government (1992 – 1997) has managed to collect only \$0.14/dollar sales compared to Loughheed's average of \$0.26/dollar sales. This gap of \$0.12/dollar of sales equates to \$3.78 billion per annum less in oil and gas revenues (based on actual value of industry sales) between 1992-1997. This amount is comparable to the average amount spent on health care between 1992 and 1998 of \$3.96 billion (based on figures in Budget '99, p. 46). While comparison of historical rent collection rates can be problematic in a strict economic sense, this comparison does provide a basis for understanding the present fiscal situation, while reflecting on past aggressiveness in rent collection.

E. Industry Production Costs

The year 1986 proved to be a significant turning point in Alberta's rent collection history. The sudden collapse in oil prices caused a sudden contraction in the oil and gas industry. Intuitively, one might expect a corresponding reduction in production costs (including exploration, development and operating) as the industry struggled to remain competitive. We might also expect that industry would pressure government to provide royalty relief, since royalties are a significant cost to industry of doing business and government represented a single agent for efficient lobbying.

Figure 8 demonstrates how these expectations were only partially carried out. In short, the burden of market adjustment was carried out primarily through reduced royalties rather than diminished costs. With the collapse of oil prices in 1986, the government did in fact respond by relieving the industry of its royalty burden. At the same time, production costs remained relatively unchanged on a per boe basis. While government oil and gas revenues per barrel fell 49% from 1985 levels, industry production costs have risen an average 2%.

Figure 8: Industry Production Costs vs. Government Revenues



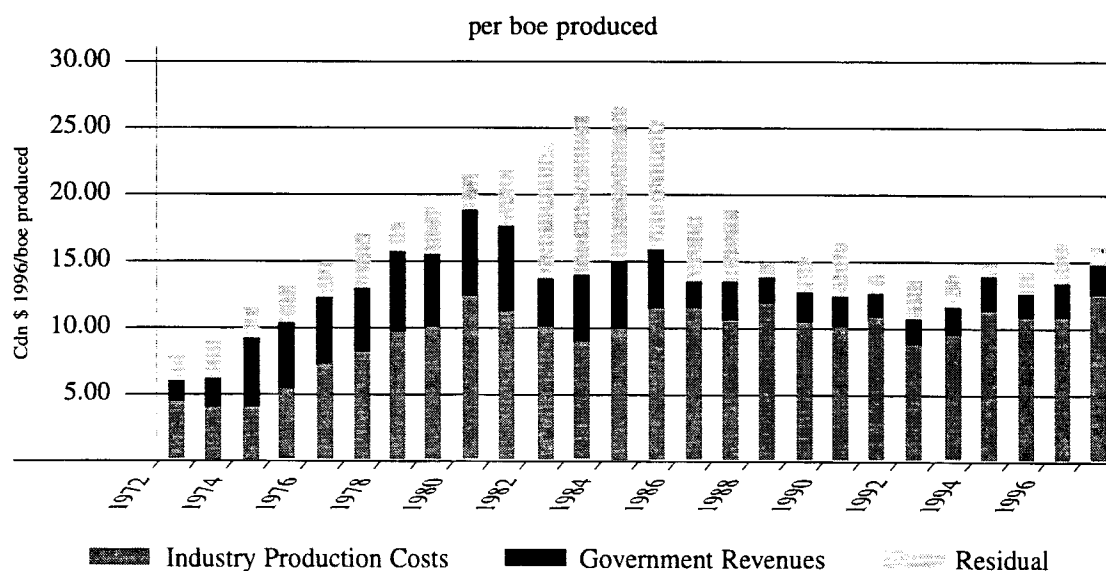
Source: CAPP and Alberta Government

While real industry production costs per unit production remained remarkably high after 1986, government revenues plummeted, as did residual rents:

- Between 1985 and 1986 the real value of producer sales/boe production fell from \$25.32/boe to \$18.12/boe – a drop of \$7.20/boe production.
- Real industry production costs declined only marginally from \$11.47/boe in 1985, to \$11.33/boe in 1986 – a net decrease of only \$0.14/boe.
- Alberta government oil and gas revenues collapsed from \$4.23/boe production in 1985, to \$1.84/boe production in 1986 – a drop of \$2.39/boe production. This drop is equivalent to a reduction of \$2.4 billion in government revenues in 1986 (based on 1986 oil and gas production).
- The residual fell from \$9.62/boe in 1985, to \$4.95/boe in 1986.

Figure 9 shows the change in the share of the value of production attributed to production costs, government oil and gas royalties/fees, and residual rents. These figures clearly demonstrate that industry costs per unit of total production have remained relatively high, while government revenues and residual rents remain permanently reduced. The reduced residual rent is significant since it shows that the market value per unit of production has been relatively low, averaging only \$15.38/boe since 1986, compared to \$25.32/boe in 1985, even though the volume of production has risen 59% since 1985. A reduced residual also means less room for governments to collect addition resource revenues and ultimately lower industry profit margins.

Figure 9: Industry Production Costs, Government Revenues and Residual “Rents”



Source: CAPP, Alberta Government Public Accounts

E.1 How much more rent could the government have collected?

Since 1986, how much of the estimated energy rents were collected by the Alberta government through royalties and fees? What share of the resource rents generated was collected by government, and what share was retained by industry, or captured in other factors of production? How much more rent could have accrued to provincial coffers?

While hindsight is usually 20-20, an examination of historical rents and rent collection performance does provide a rough sketch of the level of additional energy revenues that might have accrued to Albertans. Governments face an ongoing challenge in attempting to collect resource rents. While attempting to achieve a maximum share of resource rents, they must also be sensitive to operating conditions and investment requirements so as not to hinder sector activity and future investment. This is a continuous balancing act, requiring continuous negotiation between governments and industry to work out a suitable rent sharing arrangement.

There are many methods of calculating energy rents, and many ways of evaluating rent collection performance. The key variable to calculate is the share of resource rents collected by government, or in other words, the rate of resource rent collection. This is not always an easy calculation, given the lack of a transparent and comprehensive data on industry production cost and product prices. For example, CAPP statistics do not distinguish between conventional crude oil and natural gas production costs. In addition governments must build in assumptions about allowances of capital costs and profit margins in the determination of resource rents and royalty policy. This exercise is complex and ultimately requires a trusting relationship between government and industry, where government, as steward of the resource, effectively charges industry for the right to access and develop a public resource.

This analysis provides a starting point for future rent collection performance analysis and reporting. Others have made attempts to estimate Alberta energy rents including Smith (1992), Born (1992) and Anielski (1997) (See Appendix 1). The Smith (1992) and Anielski (1997) approaches are similar, but differ from the Born estimates in the treatment of capital. We believe the Born method used in estimating Alberta oil and gas rents in the development of oil and gas natural

capital accounts for Statistics Canada is the most appropriate approach to rent determination. Born depreciates the capital expenditures using straight-line depreciation methods and also includes an allowance for return on capital investments equivalent to long-term bond rates. However, the Born analysis only covers the period 1962 to 1989. Anielski (1997) extends the accounting to 1997, but treats capital as Smith did, allowing for the 100% expensing of capital against revenues with a provision for return on capital investment.

The simplest approach to estimating rents is to take a corporate "net cash flow" approach – the net of the market price of oil and gas produced, less all exploration, development and operating costs recoverable on 100% first-year basis (Kemp and Watkins, 1987). Government energy royalties and other fees collected relative to net cash flows can be used to assess what percentage of revealed rents were collected.

We used two approaches to estimate Alberta's energy rents: the "net cash flow" method and the "Born" method. The two methods differ in their treatment of fixed capital expenditures (development and capital).

1. The net cash flow method is simply the net of the value of producer sales and all production costs (no depreciation of capital and no provision for return on capital investment). This yields energy rents before profits, dividends, royalties (and fees), corporate income taxes, and royalty tax credits.
2. The "Born" method is adopted from the Born (1992) and Anielski (1992) estimates using the Born figures up to 1989, then projecting the Born figures forward to 1997 based on the Anielski estimates for 1992 to 1997. The Born method treats capital as accounting conventions would, by including a provision for the depreciation of fixed capital expenditures over the productive life of the asset (the oil and gas reserve). It also provides for a "normal" return on capital investment (using the average yield on long-term corporate bonds reported in the Bank of Canada Review, 1992, p. 31). The Born estimates are distinguished from the "net cash flow" method in that they include an allowance for a normal return on investment.

Both methods provide very crude estimates of energy resource rents generated from Alberta's oil and gas production. Only a more thorough analysis of energy production costs (by petroleum product) will yield a more accurate assessment of rents and rent collection performance.

Both methods yield slightly different estimates of surplus or residual energy rents before governments collect a share through royalties (net of royalty tax credits). These surplus rents include profits, investor dividends, and possibly market access or monopoly rents. Some would in turn be captured through federal and corporate income taxes on taxable income. Ideally, all energy rents could be collected through an ex ante bonus-bid system and an ex post system of a royalty tax.

Such an analysis is highly complex, and our analysis can contribute only tentative estimates. Ultimately, the issue of the equitable distribution of surplus resource rents between government and industry is a public policy issue requiring value judgements. There is no definitive answer to how energy resource rents should be shared. Certainly, the history of Western Canadian resource development has tended to encourage industrial expansion over maximum resource rent collection. Yet the issue is of critical importance to all Albertans in the year 2000, as owners of increasingly scarce, and strategically important oil and gas resources.

In part, we are seeking evidence of what Copithorne (1979) calls market access rents or monopoly profits retained by industry in the form of excessive dividends, excessive earnings, high profit margins, excessive industry salaries, transnational corporate out-of-province redistributions of earnings, or uncompetitively high production costs. Of course, finding such evidence is difficult given the vertically integrated, transnational nature of the oil and gas sector. Some rent dissipation may have already occurred through production costs that would include high salaries and possibly uncompetitively high operating and development costs. Only rigorous international comparisons might reveal whether Alberta's production costs are less competitive.

The treatment of capital expenditures in the determination of rents is probably the most important issue of debate. Are capital costs treated liberally, by allowing a 100% deduction as if these were annual operating expenses? Alternatively, are capital costs treated according to accounting conventions, depreciated either over the life of the asset or over the expected production life of the oil and gas reserve? The treatment used will make a significant difference in rent estimates. Certainly treating capital expenditures like operating costs is a very liberal treatment, yet we do so only for simplicity of the calculation. Future research and analysis should be conducted to assess rents under various capital depreciation scenarios.

Table 4: Oil and Gas Rent Estimates (in Constant 1996 Dollars)

	"Born" Rent Estimates (before royalties) \$ millions	"Net Cash Flow" Rent Estimates (before royalties) \$ millions	Government oil and gas revenues \$ millions	Estimated Residual before-tax Rents (Born) \$ millions	Estimated Residual before-tax Rents (Net Cash Flow) \$ millions
1972	3,441	3,331	1,345	2,097	1,986
1973	5,519	5,173	2,179	3,340	2,994
1974	8,750	7,495	5,254	3,497	2,241
1975	9,779	7,430	4,585	5,195	2,845
1976	10,416	7,014	4,580	5,835	2,434
1977	12,227	8,169	4,433	7,794	3,735
1978	11,881	7,798	5,416	6,465	2,382
1979	14,074	9,211	5,526	8,547	3,685
1980	14,524	9,106	6,474	8,050	2,632
1981	12,772	10,044	5,923	6,849	4,122
1982	15,023	13,104	3,779	11,245	9,326
1983	16,281	15,763	4,620	11,660	11,143
1984	18,277	16,450	4,976	13,301	11,475
1985	17,562	14,622	4,470	13,092	10,152
1986	6,568	6,762	1,836	4,732	4,926
1987	6,561	8,404	2,891	3,671	5,513
1988	2,180	3,617	2,384	(204)	1,232
1989	2,442	5,777	2,454	(12)	3,323
1990	7,921	7,466	2,724	5,197	4,742
1991	3,247	3,819	2,036	1,212	1,783
1992	6,471	6,291	2,187	4,285	4,104
1993	5,359	6,306	2,853	2,506	3,453
1994	2,154	4,998	3,398	(1,244)	1,600
1995	2,635	5,139	2,761	(126)	2,378
1996	7,130	8,644	3,884	3,245	4,760
1997	2,695	5,509	3,575	(880)	1,934
average (1992-97)	4,407	6,148	3,110	1,298	3,038

Source: Born, Alice (1992), *Development of Natural Resource Accounts: Physical and Monetary Accounts for Crude Oil and Natural Gas Reserves in Alberta*, Statistics Canada

Anielski, Mark (1997), *Is Alberta Running Out of Nature's Capital?*

Smith, Roger (1992), *Income Growth, Government Spending and Wasting Assets -- Alberta's Oil and Gas*. Canadian Public Policy - XVIII 4:387-412

Government of Alberta Public Accounts

Note: Born residual rates include a normal rate of return on capital investment. "Net Revenue, cash-basis" rents do not.

Taking our estimates of gross rents we then net out royalty payments, bonuses, and Crown lease sales, and adjust for the Alberta royalty tax credit as a benefit to industry. This leaves us with an estimate of "residual" rents, before income taxes.

We estimate that "residual" pre-tax energy rents (net of royalties and tax credits) averaged between \$1.30 billion ("Born" method) and \$3.04 billion ("net cash flow" method) per annum between 1992 and 1997 (see Table 4.) While the two figures are not entirely comparable, since the Born figure already makes an allowance for a normal return on investment, they provide a rough range of pre-tax resource rent estimates that have been retained by industry. Assuming the two estimates are comparable, the difference between the two estimates of \$1.7 billion would presumably include the "normal" return on investment to industry, plus provision for capital depreciation. Born's figures did not provide sufficient detail to distinguish how much of this amounted to a return on capital investment. Note that the Alberta government's oil and gas revenues over this period averaged \$3.1 billion per annum.

What would constitute a suitable proportion of resource rents collected by government is difficult to specify. Using the "net cash flow" rent figures (before-tax) in relationship to energy revenues collected, we estimate that between 1992 and 1997 the Alberta government captured roughly 51% of energy rents. Kemp and Watkins (1987) estimated that post-National Energy Program (up to 1986), the Alberta government's "take" of energy rents averaged between 38% for large reservoirs and 26% for smaller reservoirs. They also estimated that the Federal government's "take" at 25% of rents from both the larger and smaller reservoirs. Combined, this means that the Alberta/Federal government collected 63% of total energy rents from large reservoirs, and 51% for smaller reservoirs. Our figures are not necessarily comparable with Kemp and Watkins, given differences in data sources and methodologies.

Whether 51% of net cash flow energy rents collected is sufficient is debatable. Kemp and Watkins (1987) argue that "adopting a criterion of, say, two thirds to three quarters (of energy rents collected by government) would leave scope for efficiency incentives, allow for a margin of error, and provide a source of funds for resource companies." According to Noreng (1999) Norway set out to capture 70% of energy rents and the UK 77% of energy rents.

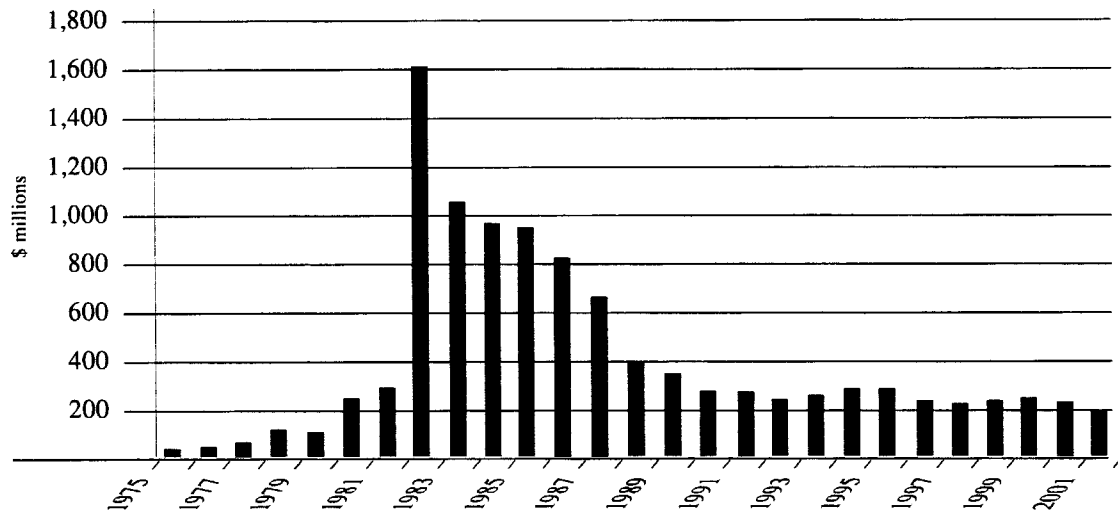
Our estimated "residual" rent is what might be considered as taxable income generated by the industry. This residual or surplus rent would include profits, and dividends to investors. Companies and investors are entitled to a reasonable, if not attractive rate of return on their investments. But these residual rents also represent Alberta energy rents that have not otherwise been collected through royalties and other energy rent collection instruments, and that could potentially accrue to the federal government (and the province) in the form of corporate income taxes.

As noted above, there is no record in Alberta's public accounts that identifies the amount of provincial or federal corporate income tax paid by the petroleum industry. Any such evidence must be specially requested from the government, or discerned by examining corporate annual reports for reported "current" and "deferred" income taxes. How much income tax is actually paid is difficult to determine, as case studies of the U.S. petroleum industry indicate.²⁰ Using reported "current taxes" paid by the Canadian petroleum industry (Canadian Petroleum Perspective), we estimated that Alberta producers paid an average \$0.30/boe production ("current taxes" include federal and provincial corporate income taxes and municipal taxes, but exclude royalties). On the basis of actual production volumes for the Alberta industry, this would amount to an estimated \$443 million/annum in corporate income taxes and other government taxes for Alberta producers from 1992 to 97.

Alberta's energy industry has benefited handsomely from direct subsidies and through various forms of tax credits over the years as the following figure shows. If one were to examine the public record of corporate income taxes paid to the province, one would undoubtedly find that the industry received more in tax credits, than they paid in corporate income taxes. The estimated \$433 million in federal/provincial corporate income tax paid between 1992 and 1997, compares to an average \$268 million in subsidies (royalty tax credits) per annum in the same period. In effect, the Alberta Royalty Tax Credit can be viewed as a tax subsidy or transfer payment from corporate income taxes paid by other corporations to the Alberta oil and gas industry.

²⁰ Using reported "current taxes" paid by the Canadian petroleum industry as reported by the "Canadian Petroleum Perspective" (a Canadian oil and gas research organization), we estimate that Alberta producers paid an average Cdn \$0.30/boe production ("current taxes" include federal and provincial corporate income taxes and municipal taxes, but exclude royalties). On the basis of actual production volumes for the Alberta industry, this would amount to an estimated \$443 million per annum in corporate income taxes and other government taxes for Alberta producers from 1992-97. Whether oil and gas producers actually pay income taxes in accordance to what is reported as a "payable" on their books has been questioned in the U.S. A recent report by Douglas Koplow and Aaron Martin (Industrial Economics Inc., Cambridge, Mass.) found that while "statutory tax levels required U.S. oil companies to pay 34.7% of their income during 1992-95, the average tax paid by the companies was only 8.7%." (Oil and Gas Journal, 1998). They also estimated that "subsidies (to the US oil and gas industry) are nearly \$ 12 billion" or "worth \$ 1.20-2.80/bbl consumed, which equates to 3-6.5% of U.S. consumer spending on petroleum products in 1995.

**Figure 10: Alberta Government Royalty and Other Tax Credits
in Alberta's Petroleum Industry**



Netting out the provision for corporate income taxes would leave between \$844 million ("Born" method; \$0.88/boe), and \$2.58 billion ("net cash flow" method) per annum (\$1.78/boe produced) in post-tax residual/surplus rents between 1992 and 1997. This is an estimate of how much energy resource rents were retained by industry and investors. The Born estimate is essentially the amount of rent retained by industry over and above a "normal" return on investment. Whether this is too much, too little or sufficient is debatable.²¹

These figures might be used as a very crude basis for comparing Alberta with both our historical, and international benchmarks which showed that Alaska collected on average \$1.33 more per unit of production, and Norway \$4.00 more per unit of production than Alberta.

Some of this surplus or residual rent would include dividends to investors, retained earnings and other possible monopoly profits retained through the integrated network of transnational oil and gas companies operating in Alberta. Investors are entitled to a reasonable return on investment, and firms entitled to returns on equity should be sufficient to encourage sustained investment in the industry. The question remains: how much profit is reasonable, and how much should Albertans expect to receive as their share of resource rents?

²¹ As noted earlier it would be useful to determine how much of the difference between the Born estimates and the net-revenue-cash-basis estimates are attributed to a normal return on investment.

We then examined financial statistics for the Canadian oil and gas industry to determine financial performance. We found a situation where industry profitability remains high, while provincial revenues deteriorate:

- Figures from the Canadian Petroleum Perspective of 110 Canadian oil and gas companies show that profit margins averaged 19% between 1992 and 1997.
- Examining Toronto Stock Exchange (TSE) financial statistics revealed that dividends paid to investors averaged \$356 million between 1992 and 1997, while corporate earnings (profits) averaged \$1.3 billion per annum.
- The TSE Total Return Index (TRI)²² for the Canadian oil and gas sector in 1997 was 145% higher, dividends were 65% higher, and earnings were 231% higher compared to 1985, our benchmark year.
- Dividends have risen steadily from \$281 million (current dollars) in 1985 to \$463 million in 1997, falling slightly to \$445 million in 1998 with the oil price slump.
- While dividends have risen since 1985, provincial oil and gas revenues per boe produced in 1997 have increased only marginally relative to 1985. Provincial oil and gas energy revenues in 1997 were 17% lower than in 1985, or 49% lower per boe (all figures in current dollars).

In the end, any estimate of rents is only a best guess estimate. Our analysis is certainly preliminary and illustrates the complexity of rent estimation. A more rigorous analysis of energy rents would require various alternative treatments of capital costs. Ultimately, informed by such information and analysis, it is Albertans who must decide whether they are receiving a fair return on their oil and gas resources. Without such information, an informed public policy debate cannot begin. Just like investors in corporate stocks, Albertans are entitled to an annual report on their natural wealth endowment and the return they are receiving. While no rent analysis can resolve the issue of equity and fairness, it can at least enlighten the debate.

²² Total Return Index is the broadest index of the performance of a sector. The TRI is a measure of the investment through time based on price appreciation of shares but also due to the reinvestment of dividends.

F. How much oil and gas rents would Albertans have received under various benchmark rates?

An enlightened debate about rent collection cannot be done without benchmarks. Our analysis estimated the amount of rent Albertans might have received using the benchmark rent collection rates of the Lougheed era, Norway, and Alaska (see Figure 11). Certainly, interpretation of these comparisons should be tempered by many caveats, especially since not all the factors that make up energy rents in each of the jurisdictions (production costs, prices, operating conditions) are necessarily equal. Nonetheless, the comparisons reveal significant differences that become part of a more informed discussion and inquiry into performance differences across time and jurisdictions.

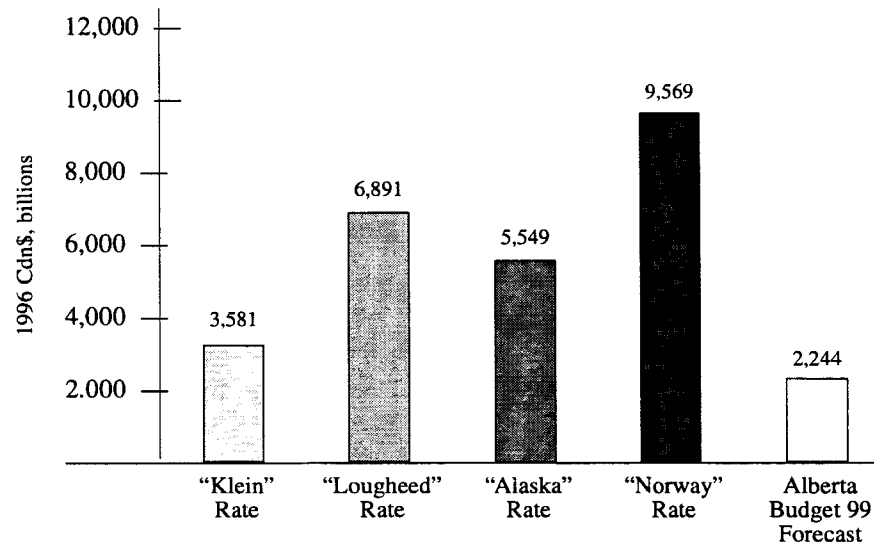
Using the "Lougheed", "Norway" and "Alaska" benchmarks, the amount of potential additional oil and gas revenues Albertans would have received between 1992 and 1997 can be estimated (see Figure 11.)

At the historical "Lougheed" rate of \$4.67/boe production, Albertans would have received \$6.89 billion per annum. This would have meant an additional \$3.78 billion per annum in oil and gas revenues between 1992 and 1997. In comparison, the average Alberta health care expenditures between 1992/93-1997/98 averaged \$3.96 billion (Budget '99). This means that under the Lougheed administration, Albertans received 1.55 times more per barrel of oil and gas than under Ralph Klein.

At the "Alaska" rate of \$3.74/boe production, during the period 1992-1997 Albertans would have received \$5.55 billion per annum. This would have meant an additional \$1.97 billion per annum in revenues. Alaskans received 1.55 times as much per barrel of oil and gas produced.

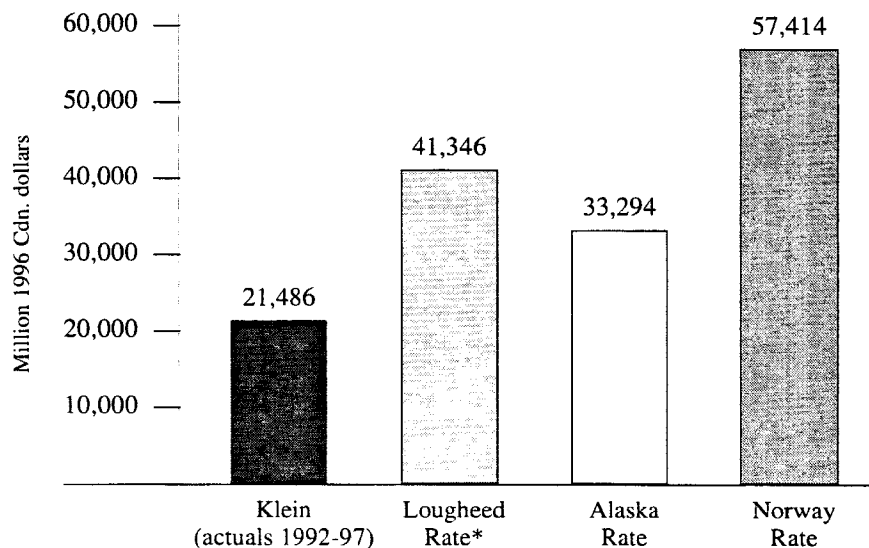
At the "Norway" rate of \$6.41/boe production, Albertans would have received \$9.57 billion per annum between 1992 and 1997. This would have meant an additional \$5.69 billion per annum in oil and gas revenues. Norwegians received 2.7 times more in oil and gas revenues per barrel of oil and gas produced.

Figure 11a: Estimated average annual oil and gas revenues Albertans would have received between 1992 and 1997 under various benchmark rates



Note: The "Loughheed" Rate and the "Alberta Budget '99" Forecast figures exclude corporate income tax revenue estimates. Source: Calculated based on Alberta Government, Norwegian Ministry of Petroleum and Energy, Norwegian Ministry of Finance, State of Alaska (Department of Revenue & Department of Natural Resources)

Figure 11b: Estimated Alberta Oil and Gas Revenues Had Albertans Received the Various Benchmark Rates Between 1992 and 1997



* all figures, except the Loughheed Rate, include corporate income tax revenue estimates

Alberta Government Program Expenditures

	Basic and advanced Education	Health	Total Program Spending	Total Expenses (include debt servicing costs)
92-93	4,079	4,164	16,176	17,595.00
93-94	4,147	4,033	15,123	16,777.00
94-95	3,794	3,829	13,497	15,243.00
95-96	3,662	3,654	12,780	14,463.00
96-97	3,682	3,842	12,796	14,258.00
97-98	4,101	4,235	13,873	15,195.00
average	3,911	3,960	14,041	15,589
Change between 1996-97 and 1992-93	(397)	(322)	(3,380)	(3,337)
Change between 1997-98 and 1992-93	22	71	(2,303)	(2,400)

Source: Budget '99 p.46

To put these foregone revenue estimates into perspective, consider that by 1996-97 the Alberta Government had cut program spending by \$3.38 billion compared to 1992-93 (excluding debt servicing expenditures) (see Table below). Consider that spending on health care averaged \$3.96 billion per annum, and \$3.91 billion on basic and advanced education between 1992/93 and 1997/98 (Budget '99, p. 46). The magnitude of the estimates of potential energy rent revenues foregone – \$1.97 billion (Alaska) to \$5.69 billion (Norway) – are given a sharp political perspective. This raises the following question: did Alberta squander revenue capacity by not pursuing its energy resource rents and royalty policies more rigorously?

G. Questions About Oil Sands

Former Energy Minister, the Hon. Pat Black (Nelson), once noted that the oil sands is the greatest strategic resource possessed by Canada. With an estimated 300 billion barrels of recoverable synthetic/bitumen crude oil, the oil sands is as significant a strategic reserve to the U.S. as Saudi Arabia's 262 billion barrels of light conventional crude oil (the world's largest conventional crude oil reserve). At current rates of production, the Alberta oil sands could continue to produce for 1,500 years.

Until recently, oil sands production yielded relatively small royalty revenues, averaging only \$0.31 per barrel of oil produced from 1986 to 1993, compared to an average \$3.52 per barrel for conventional crude oil. Low rent collection could be justified on the basis that the oil sands was a frontier, high-risk and capital intensive resource development.

In 1993, however, oil sands royalties began to rise dramatically peaking at \$2.93 per barrel in 1996. This rise was presumably due to the old oil sands royalty formula, which collected higher rents as capital costs were amortized and as production costs declined. Indeed, operating costs per barrel of oil sands production in 1997 had fallen dramatically to an average \$8.83 per barrel (1996 dollars) compared to \$24.00 per barrel in 1979. Based on CAPP statistics, in 1997 average operating costs for oil sands production were 13 % lower than for conventional crude oil (\$9.96 per barrel).

Falling operating costs were the result of years of public and private investment in research and development of oil sands technology. As a result, production costs on what is effectively a mining operation are now significantly lower than 10 years ago. This resource source has apparently become more competitive than conventional crude oil production. Some developers (C.S. Resources of Calgary) of insitu oil sands (the next frontier of oil sands development) expect extraction costs to fall to roughly Cdn \$5.00 per barrel in the near future (Energy Economist, 1998).

Historically, oil sands royalty regimes varied according to the producer: Suncor, Syncrude and Imperial Oil at Cold Lake had all negotiated different royalty regimes. This all changed in 1995 with the introduction of the generic oil sands royalty regime (see Masson and Remillard, 1996; Western Centre for Economic Research (1995)).²³

²³

Prior to the generic oil sands royalty regime introduced in 1995, Suncor paid a net royalty calculated as the greater of 30% of net revenues or a minimum 5% of gross production. Suncor was allowed capital and operating costs to be grossed up by 1% and 10% respectively, for determining net revenues. Syncrude paid 50% of the project's deemed net profit as a royalty and also had a minimum royalty on gross production. Capital spending was amortized rather than deducted as spent in calculating deemed net profit. Imperial Oil's insitu Cold Lake project consisted of a 1% royalty on gross revenue at startup, increased by 1% every 18 months to a maximum of 5%. Imperial's royalty remained at 5% of gross production until payout (when gross revenue exceeds cumulative operating costs, capital costs, gross royalty, and 10% return allowance on unrecovered costs), at which point it converts to the greater of 30% of net revenues or 5% of gross production. Capital and operating costs were grossed up by 1% and 10%, respectively.

In a symposium on "Competitiveness and Resource Taxation: A Case Study of the Oilsands" held in October 1995, then Energy Minister Pat Black stated that the government could no longer offer subsidies, royalty waivers, tax breaks, or take an equity position in oil sands projects.

On November 30, 1995, Premier Klein announced a new generic oil sands royalty system for Alberta's oil sands. The new royalty systems had four main objectives:

1. Accelerate the development of the oil sands;
2. Facilitate development of the oil sands by private sector companies;
3. Ensure that oil sands development is competitive with other petroleum development opportunities on a world scale, and
4. Create a standard set of royalty terms.

Notice that not one of the objectives was the maximum return to Albertans from this significant global energy resource.

The basic elements of the new resource rent royalty system included the following two options:

1. A 25% royalty payable on net project revenues after the developer has recovered ALL project costs (including 100% of capital/development costs in the year incurred), plus a return allowance set at the Government of Canada Long-term Bond Rate plus inflation (roughly 10%);
2. Or, if the first condition could not be met, the industry would pay a minimum 1% royalty payable on all production.

History of Alberta's "Generic" Oilsands Royalty Regime

"In the spring of 1995, the Task Force released a comprehensive report outlining a detailed list of recommendations for the oil sands industry. The Task Force proposed a uniform oil sands royalty system based on a specified percentage of net project revenues after all costs are recovered. This type of resource rent royalty had been used in the ad hoc oil sands agreements for decades. By the end of 1987, all existing oil sands projects that held royalty agreements had some form of a net revenue royalty. Alberta's experience with net revenue royalty agreements provided a foundation for the Task Force's recommendations and for the new royalty system to promote investment in oil sands development.

The National Oilsands Task Force recommended that the net revenue royalty rate be set at 25%. Based on the analysis the Task Force completed, this rate was viewed as providing an appropriate incentive for oil sands development, while still providing a sufficient return to Alberta from the oil sands resource. In combination with federal and provincial income taxes, after project payout, a 25% net revenue royalty results in the developer receiving marginal project income of 38%, with the balance of 62% going to the federal and provincial governments through royalties and corporate income taxes. Analysis based upon net present value of corporate and government revenues discounted at 10%, based upon a typical grassroots project economics estimated by the National Task Force on Oil Sands Strategies (1995). Developers pay other taxes, such as municipal property taxes, as well.

In theory, Alberta could attempt to capture to 100% of the economic rent from an oil sands project. This could mean that when the developer recovered his costs, including a return equal to his risk adjusted cost of capital, Alberta would receive 100% of incremental project revenues. This would have been inappropriate because:

Cost reduction has been a key factor in making oil sands development more attractive. A royalty rate that captured too much marginal cashflow would have resulted in a reduced incentive for cost reduction and innovation. This is the "gold plating" argument that if marginal tax rates are too high there is an incentive to spend additional cashflow rather than seeing it go to governments through royalties and taxes which provide no tangible benefit to the project. The measurement of project costs is a difficult matter, particularly when project related activities are performed at corporate offices located away from the project and when there are inadequate systems to allocate corporate overheads such as management and computing cost.

The federal corporate income tax system is not integrated with Alberta's royalty system -- rather than providing for the deductibility of royalties in the calculation of federal taxable income, the system allows for a "resource allowance" which is 25% of defined "resource profits". This resource allowance could result in double taxation if the royalty rate is set too high.

If the net revenue royalty rate is very high, the return allowance rate would have to equal a developer's risk adjusted cost of capital in order to ensure that royalty is only collected on the project's economic rent rather than on the return to capital. Even if accurate identification and measurement of all project costs could

occur, each project would still have a unique risk adjusted cost of capital. The simpler approach chosen is to establish a single return allowance rate for all projects. Alberta chose to set the return allowance rate below developers' cost of capital, and the net revenue royalty rate below the level that would capture 100% of the project's rent.

By not trying to measure all project costs exactly, and leaving the potential for developers to capture some of the economic rent of successful projects, Alberta's royalty system encourages developers to innovate to maximize the efficiency and resource recovery from their projects."*

The new formula minimizes government resource rent revenues for new developments as well as existing production. It does this by providing generous capital cost right-off provisions until project payout, and after a rate of return on capital investment equivalent to the long-term bond rate plus 2% (roughly 10%). The province will collect 25% of the net rents or net revenues generated by production, but only after all project costs are paid out and an equivalent of almost 10 % return is achieved. The treatment of capital costs is generous. It allows full expensing of fixed capital costs, rather than amortizing these costs over the life of the project as per regular accounting conventions. According to the Energy Economist, this treatment is "attractive, greatly reducing front-end burdens and overall risk" for the industry. **In effect Albertans are assuming most of the risk of these huge capital investments through this provision. Even in the most liberal interpretation of economics, this treatment of capital costs amounts to a subsidy to industry, with Albertans sharing a disproportionate amount of the risk.**

While the new system was based on the technical merits of a resource rent royalty structure, it represented a departure from the historical oil sands royalty regimes, particularly in the treatment of fixed capital in the determination of net revenues or rents. The new system was intended to encourage the \$18 to \$25 billion in new capital investment that had been predicted by industry in 1997. The system clearly reduced the risk of these capital investments to the industry, while Albertans forego significant royalty revenues. While the new system is intended to encourage new capital investment, existing oil sands producers would also fall under the new generic regime, even though it is not clear how existing production should be treated from a royalty perspective.

* Source: extracted from "Alberta's New Oil Sands Royalty System" by Richard Masson and Bryan Remillard Royalty and Tenure Branch, Policy Division, Alberta Department of Energy, Edmonton, Alberta, Canada. www.energy.gov.ab.ca/sands/royalty/oilsand1.htm

As a result of these changes, royalty revenues for oil sands followed an unusual path in the 1990s. After languishing at \$12 to \$67 million between 1986-87 and 1993-94, oil sands royalties suddenly surged to \$512 million in 1996-97, presumably as a result of the historical royalty regimes which began to collect higher rents on net revenues. Since the introduction of the generic oil sands royalty regime, royalties from oil sands production has dropped dramatically to \$192 million in 1997-98 and is forecast to fall to \$63 million in 1998-99 and to a dramatic low of \$22 million in 2001-2002. Some of this drop of almost \$490 million (between 1996/97 to 2001/2002) can be attributed to a fall in oil prices, but not all of it. We must ask why royalties would fall so dramatically on existing production that was just beginning to yield healthy net revenues?

The Alberta Energy Minister, Dr. Steve West, has indicated that Albertans will only begin to realize higher oil sands royalties by 2015 as the huge capital costs associated with these investments are written off. But why should Albertans wait 15 years before realizing a reasonable return on their investment in the free gift of nature? Why should such a valuable and strategic resource, while capital intensive, receive such a generous allowance for capital costs vis-à-vis other industries in the determination of royalties? Why have oil sands royalty revenues fallen so dramatically, even before the new oil sands production comes on stream under the new generic oil sands royalty regime? Why now, after years of public investment in oil sands technology development, are Albertans receiving so little in return from their investment? The generous treatment of capital costs, while undoubtedly encouraging maximum capital investment, also ensures a sustained meagre royalty revenue stream based on a minimum 1% of production royalty – a trend that will continue so long as there are capital costs to be expensed.

The fundamental issue affecting future royalty revenues is the treatment of capital, which will take different forms depending whether you taken the position of an economist, or an accountant. Depreciation is simply an accounting instrument that represents an allowance for the decrease in value of property through wear, deterioration or obsolescence. Depreciation allowances for various assets have a significant impact on the determination of taxable income for corporations. In accounting conventions the depreciation provisions effectively constrain a corporation from expensing its capital costs as if they were current operating expenses, and thus ensures governments collects adequate corporate income taxes. In principle, the treatment of capital costs should be consistent whether it is for tax purposes, or royalty purposes.

Depreciation allowances can have a significant impact on investment decisions. Undoubtedly, the generous treatment of capital costs in the case of oilsands will have the desired effect of encouraging expansion of oilsands infrastructure. Firms will be encouraged to maximize capital costs to ensure the minimum 1% royalty payable on production. It may be years until the 25% of net revenue royalty rate of rent collection comes into effect.

Ironically, the allowance of 100% or full expensing of capital is similar to how public infrastructure assets are treated. In Canada, public assets such as bridges, roads, hospitals, or other infrastructure investments, are fully written-off in the public accounts in the year they are constructed, and assigned a nominal value of \$1 in the public books. Attempts are being made, notably by Alberta and the U.S. government, to correct this public accounting anomaly.

Contrasting the oilsands' capital cost allowance formula with public utilities, and corporate taxation standards provides useful benchmarks. The Mintz report on Business Taxation released in December 1997, recommended major changes to the write-off allowances for capital that related to corporate taxation. The report made two recommendations related to oil and gas and mining operations:

1. The first recommendation was that "maximum rate of write-off on development costs in both mining and oil and gas should be reduced from 30% to 25% on the declining balance for expenses incurred after a three-year period of advance notice."
2. Secondly, related to oilsands "mining" operations, the report recommended that "capital costs incurred in connection with new mines or major expansions of existing mines should not be immediately claimable in full against the income from the project. Rather such costs should be placed in a new class and only be deductible up to a maximum of 25 % of the declining balance."

Although the recommendations apply to corporate income taxation, they would presumably be relevant to royalty policy of provincial governments. Allowing full expensing of oilsands capital costs in determining royalties payable goes directly against the Mintz reports' recommendations.

Some might argue that such treatment of capital is a necessary "carrot" to attract

these apparently high-risk investments. Yet it is not entirely clear that such investments would not otherwise occur without such generous allowances. For example, Norway is expected to see massive investment of some US\$11 billion in offshore natural gas and oil development, and yet expects to collect significantly more in resource revenues per unit of production (over Cdn. \$12.00/boe forecast for the year 2000) without the generous capital cost treatment (Norwegian Ministry of Petroleum and Energy).

Certainly the creation of employment opportunities in Alberta's petroleum industry are important. Yet according to the free-market logic (logic frequently cited by the Klein administration), industry should be making these investment decisions on the basis of free and competitive market conditions, without the generous support of government royalty regimes. To reiterate this key point, it could be argued that the treatment of capital constitutes a subsidy to industry and Albertans ultimately are bearing a disproportional amount of the risk of these capital investments. Paradoxically, the generous treatment of Alberta's oil and gas industry government may unwittingly leave the industry less competitive, and Albertans with less resource revenues than might otherwise be the case. Compared to other jurisdictions like Norway, it appears that Alberta government policy favours expanded resource development over maximum rent collection.

What is the price of this strategy in terms of lost future earnings? It is to this question that we now turn.

H. Future Energy Rents...

According to Budget '99, the resource rents from oil and gas will continue to decline (see Figure 12.) Based on forecasts from the Alberta Government's Budget '99, rent collection (i.e. royalties and fees) per unit of oil, gas and gas byproduct production is expected to reach its lowest level in four decades, reaching an unprecedented average low of \$1.25/boe (converted to 1996 constant dollars this equates to \$1.19 boe, according to the government's projected inflation rate) between 1998 and 2001. Albertans have never realized a lower rate of return on their oil and gas resources. The previous record low was recorded in 1991 at \$1.69/boe.

The forecast rate of \$1.19/boe (constant 1996 dollars) between 1998 and 2001 is even lower than the already low average of \$2.10/boe (excluding corporate income taxes paid) realised between 1992 and 1997. Part of this decline is due to the forecast decline in oil prices (which have since increased), as well as an expected fall in bonuses and Crown lease sales of \$357 million (\$0.17/boe) in 2001-2002 compared with 1996-97.

However, not all of the decline in conventional and oilsands royalty revenues can be attributed to the forecast oil price decline. The decline in oilsands royalties is due largely to the generic oilsands royalty regime. On a positive note, Alberta royalty tax credits are forecast to fall to \$191 million by 2001-2002 compared with \$240 million in 1996-97 (a reduction of \$50 million). Even so, the projections for future resource revenues, broken down into greater detail, do not look promising:

Oil and gas revenues are forecast to decline from \$3.88 billion in 1996-97, to \$2.10 billion in 1998-99, then recover marginally to \$2.72 billion by 2001-2002 (a decline of \$1.17 billion from 1996-97).

Royalties from conventional crude oil were expected to decline by 70% (or \$973 million) from \$1.39 billion in 1996/97 to \$413 million by 2001-2002. On a per barrel basis, conventional crude oil royalties were expected to fall 70% from \$4.17/barrel in 1996-97, to \$1.24/barrel by 2001-2002. This decline will occur despite the fact that the forecast price of oil in 2001-2002 (Cdn \$19.99/barrel, Alberta Wellhead) was expected to fall only 28% compared to the 1996-97 average price.

The drop in oil sands royalties is most significant. Compared to 1996-97 oil sands revenues (\$512 million), the forecast for 2001-2002 is only \$22 million, a drop of some \$490 million. This decrease will occur in spite of an expected doubling of oil sands production in the next few years. The decline in royalties on a per barrel of production basis is even more significant. From \$2.93/barrel in 1996-97, royalties will fall to a meagre \$0.08 per barrel, the lowest rate ever realized in the history of oil sands production.

Total crude oil royalties were expected to fall to \$1.46 billion by 2001-2002 relative to 1996-97, a drop of 77%. This decrease is substantially greater than the forecast 28% decline in the price of conventional crude oil. Also, this decline in revenue will come despite a 7% forecast increase in the production of oil from both conventional and oil sands reserves from 563 million barrels per annum (1,544,000 barrels per day) in 1996-97 to 601 million barrels per annum (1,647,000 barrels per day) by 2001-2002.

Natural gas royalties are expected to offset some of the significant decline in oil royalties rising 47% from \$1,299 million in 1996-97 to a forecasted \$1,904 million by 2001-2002. This expansion is partly fuelled by a 29% expected increase in production from 4,865 billion cubic feet in 1996-97 to 6,278 billion cubic feet, and a 14% increase in the price of natural gas from \$1.77/mcf in 1996-97 to \$2.01/mcf in 2001-2002.

We estimate that if Albertans received the average "Lougheed" rate (\$4.67/boe) versus the forecast rate of \$1.25/boe over the next three years (1998/1999-2001/2002), an additional \$6.55 billion/annum would be collected. This amount is equal to 91% of the combined 1997-98 spending on Health (\$4.24 billion) and Education (\$2.93 billion). Even at the historical "Klein" rate (1992-97) of \$2.10/barrel oil equivalent (boe), Albertans would receive an additional \$1.6 billion per annum in oil and gas revenues than is forecast for 1999/2000 to 2001/2002.

The need for public debate and regular resource rent collection accounting is even more important when one considers what remains of Alberta's gifts of nature. The bad news is that at 1997 levels of production, there are only 6.9 years of conventional crude oil production remaining and 10.5 years of natural gas. Both are mainstays of Alberta's oil and gas revenues. Reserve life has been declining steadily since 1973, as reserves are drawn down and new discoveries do not keep pace with annual production volumes. The good news is that there is 1,500 years of oil sands production remaining at 1997 production levels, Alberta's long-term source of energy rents.

Even with the optimistic projected production from the oilsands, it is far from clear that the royalties from this long-term source of energy rents will be maximised to expand the quality of life for Alberta's citizens. The implications of this analysis of future resource rents are perhaps more significant than the preceding discussion of historical rent collection. Indeed Budget '99 provides even more reason for debating whether Albertans could, or should be receiving a higher return on nature's free gift of oil and gas resources.

I. Policy Implications and Recommendations

The study points to the need for a regular assessment of energy rents collected by government over time, and in comparison with other international benchmarks. As such no such assessment or account exists. Just as investors receive return-on-investment annual reports from corporations, Albertans, as shareholders in natural resource assets, should receive an annual account of the returns received from resource development. This is simply part of good and accountable governance.

The royalty policy of the government should be the concern of all Albertans, especially given the magnitude of energy rents. How much rent should be collected from the industry in royalties and taxes is a policy decision that must be informed by public debate. This requires full disclosure and knowledge of the state of this nonrenewable asset, its potential value, and how much could be collected from industry for the right of access and development. This disclosure seems logical, given that the resource belongs to all Albertans and Canadians, who are both shareholders and stewards of nature's wealth. Albertans must realize that foregoing maximum rent collection means that someone else is retaining these rents in the form of profits. The issue of fair distribution cannot be easily resolved, though transparency of resource rents generated from these nonrenewable resources must be a prerequisite for resolving the issue of equitable distribution.

In terms of future sustainable income streams from Alberta's Heritage Trust Fund stagnates, there is cause for concern, particularly in comparison with the growth and increasing dividends in the funds of Alaska and Norway. It is unlikely that future Albertans will benefit from the extraction of non-renewable resources in the way that their Alaskan and Norwegian counterparts will.

While preliminary, the benchmarking of Alberta against Norway and Alaska demonstrates the importance of such an exercise for informing public policy debate. The sheer magnitude of the differences in energy rent collection rates warrants greater scrutiny and accountability. Such accountability and benchmarking would create a level of awareness both within government and amongst Albertans. This awareness could lead to a more informed discussion of how Alberta's natural resources should be developed to achieve a balance between maximum fiscal returns to Albertans, and viability and competitiveness for the energy industry.

Had Alberta pursued rent collection at the Alaska and Norway benchmark rates, the potential revenues could have made a significant difference to Alberta's revenue picture. Had such an analysis of energy rents been available, the nature of the budgetary debates since 1993 would most certainly have led to different out-

comes. This study does not suggest that Alberta have the same rate of energy rent collection as other jurisdictions nor that these benchmarks are achievable, all things being equal. Rather, Albertans need to understand their economy and fiscal environment relative to others in order to make more informed decisions. Moreover it is precisely this kind of information and knowledge that when revealed, will empower decision makers to launch Alberta, as the Growth Summit articulated, "into a new period of economic and social development that is balanced, sustainable and aimed at creating the kind of province Albertans want in the year 2005."

Good and accountable governance necessitates an ongoing accounting of rent collection vis-à-vis other benchmarks. This study represents a starting point and an opportunity for future analysis making such accounts publicly available to all Albertans, as shareholders in this natural heritage. Albertans must continually ask of their government: are we getting the maximum return from our most valuable nonrenewable resource?

J. Postscript *The Impact of Rising Oil Prices*

Since the oil and gas rent study was completed in June 1999 the international price of oil has risen dramatically to C\$35.61/barrel (U.S. \$24.54) as of October 2, 1999 (Edmonton par price – Imperial Oil; NYMEX price as reported in the *Edmonton Journal*, Business Section). That represents a dramatic 82% increase or U.S. \$11.04 per barrel (C\$19.69/barrel) more than the *Budget '99* forecast price of U.S.\$13.50/ barrel (C\$15.92 /barrel) for 1999-2000 fiscal period.

The last time the real (adjusted for inflation) price of oil topped C\$35 per barrel was in 1984 when the price of oil averaged C\$35.37 per barrel. Also, in 1984 oil and gas royalties hit an all-time high of \$4.69 billion.

The government forecasts that, for every U.S.\$1.00 change (increase/decrease) in a barrel of oil, oil royalty revenues will increase/decrease by C\$135 million. While we cannot accurately reforecast the *Budget'99* expected oil royalties for 1999-2000 and beyond, rough estimates of the potential impact to government revenues is possible.

For example, based on the Government's formula, a price of U.S. \$24 (C\$35) per barrel relative to the *Budget* 1999-2000 forecast price of U.S. \$13.50 (C\$15.92) per barrel would add an additional \$1.5 billion in oil royalty to the \$389 million in royalties forecast for 1999-2000 revenues (based on 1999-2000 production estimates in *Budget '99* and assuming the new market price applied throughout the fiscal year).

The following table, from *Budget '99*, shows oil royalty and oil price forecasts. The current market price of C\$35.61 stands in stark contrast to the forecast of C\$15.92 assumed for 1999-2000:

Table 1: Oil Royalties and Oil Prices

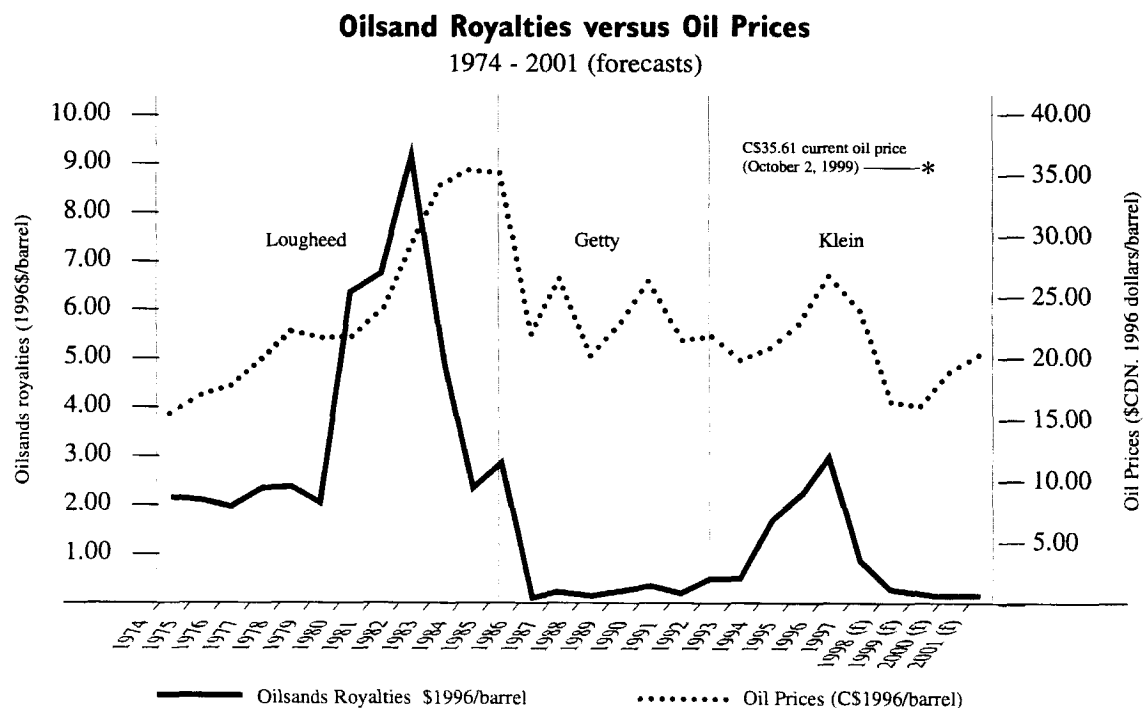
Year	<i>Budget '99</i> Total Oil Royalty Forecast (\$ millions)	<i>Budget '99</i> Crude Oil Royalty (\$ millions)	<i>Budget '99</i> Oilsands (synthetic/ bitumen) royalty (\$ millions)	<i>Budget '99</i> Oil Price Forecast (\$C/barrel)	Current Oil Price (Oct.2.99) (\$C/barrel)
1996-97 (actual)	1,898	1,386	512	27.91	
1997-98 (actual)	1,106	914	192	22.25	
1998-99 (actual)	472	409	63	16.20	
1999-2000	389	346	43	15.92	35.61
2000-2001	443	410	33	18.57	
2001-2002	435	413	22	19.99	

Of total oil royalty revenues forecast in *Budget '99* only a small portion is expected from oilsands production despite oilsands representing over 40% of total oil production. For example, in 1999-2000, of the \$389 million oil royalty revenues forecast only \$43 million or 11% was expected from oilsands production. This is a considerable drop from only 1996-97 when \$512 came from lesser volumes representing 27% of total oil royalty revenues. By 2001-2002 oilsands royalties are expected to fall to \$22 million (based on C\$20 oil prices) which will then represent only 5% of total oil royalties. This is significant given that we estimate oilsands production to reach 45% of the total volume of oil produced by 2001-2002 or almost 270 million barrels. Oilsands production will continue to increase while conventional crude oil production will either stagnate or decline.

The decline in oilsands royalties is even more dramatic on a per barrel basis. In 1996-97 every barrel of oil extracted from the oilsands yielded roughly \$2.93 per barrel (when oil was C\$27.90/barrel). By 2001-2002 the Government forecasts oilsands royalties of only an estimated \$0.08/barrel (based on \$22 million in royalties and an estimated 270 million barrels of production). That is a dramatic difference of \$2.85/barrel in royalties.

The following graph illustrates the dramatic changes in oilsands royalties relative to the price of oil since 1974 (notice where the current market price of oil sits today):

This dramatic fall in oilsands royalties is undoubtedly a consequence of the intro-



duction of the generic oilsands royalty regime and its favourable treatment of capital costs. If all things were equal and the 1996-97 per barrel oilsands royalty rate applied in 2001-2002 at the forecast oil price of \$C20/barrel, we would expect oilsands royalties of \$2.10/barrel. That is a far cry from the \$0.08/barrel suggested by *Budget '99* forecasts. Based on forecast volume of oilsands production (270 million barrels) this **represents \$567 million in foregone revenues**. This amount could be viewed as part of the value of capital cost provisions in the generic oilsands royalty.

Despite a 28% forecast increase in the oil price for 2001-2002 at C\$20 (compared with \$15.92/barrel price projected for 1999-2000), *Budget '99* actually forecasts a 58% decline in the oilsands royalties per barrel of production.

How much did oilsands royalties yield the last time oil was in the \$20/barrel range? In 1994-95 oil prices averaged C\$21.50/barrel (1996 dollars) and oilsands royalties averaged \$1.87/barrel. That's \$1.80/barrel or 22 times more than the \$0.08/barrel forecast for 2001-2002! During the Lougheed years 1977-1981, the formative stages of oilsands development, the average price of oil averaged \$21.96/barrel (in 1996 dollars) and oilsands royalties averaged \$4.00/barrel produced. This at a time when capital expenditures per barrel produced were significantly higher than today.

What might Albertans expect from C\$35/barrel oil? If the Government's *Budget '99* can be used as a guide, most of the benefit from a higher price will come from conventional crude oil production, assuming the ratio of conventional crude to oilsands royalties stays relative the same as is forecast for 2001-2002.

Historically, the last time oil prices exceeded in \$35/barrel (in 1996 dollars) was in 1984 when conventional crude oil royalties were \$2,935 million and oilsands royalties \$135 million. The oilsands royalties equate to an average of \$2.36/barrel (in 1996 dollars) production.

Let us assume oil prices remain at C\$35/barrel in 2001-2002 then we estimate \$141 million or only \$0.52/barrel in oilsands royalties, based on the *Budget '99* structure. That is a far cry from \$2.36/barrel collected in 1984 and \$4.00/barrel collected between 1977-1981. And it certainly is a far cry from the \$2.93/barrel collected in 1996-97 when the price of oil was only \$27.90/barrel. The differences are not trivial. Based on an estimated 270 million barrels of oilsands production by 2001-2002, the opportunity cost (the difference between the forecast and 1984 and 1977-81 benchmark rates) would amount to an estimated \$490 million (1984 benchmark), \$567 million (1996-97 benchmark) or \$930 million (1977-81 benchmark).

Even for conventional crude oil royalties, the comparisons with 1984 with the

same oil price scenario, are unsettling. In 1984 conventional crude oil royalties per barrel production were 7.3 times greater than the forecast for 1999-2000; in 1984 an average \$7.63/barrel was collected compared to a forecast \$1.04/barrel in 1999-2000.

When we compare oilsands (see Table 2) to conventional crude oil royalties on a per barrel basis the decline in oilsands royalties is dramatic since the introduction of the generic oilsands royalty structure. In 1996-97 the gap between conventional crude oil royalties per barrel produced and oilsands royalties was only 1.4 times. By 2001-2002 the gap widens considerably to 15.5 times as oilsands royalties fall to a mere \$0.08/barrel compared with conventional crude oil royalty of \$1.24/barrel. Even the conventional crude oil royalties forecast for 2001-2002 based on C\$20/barrel oil would appear unusually low relative to 1996-97.

Table 2: Conventional Crude and Oilsands Oil Royalties per barrel

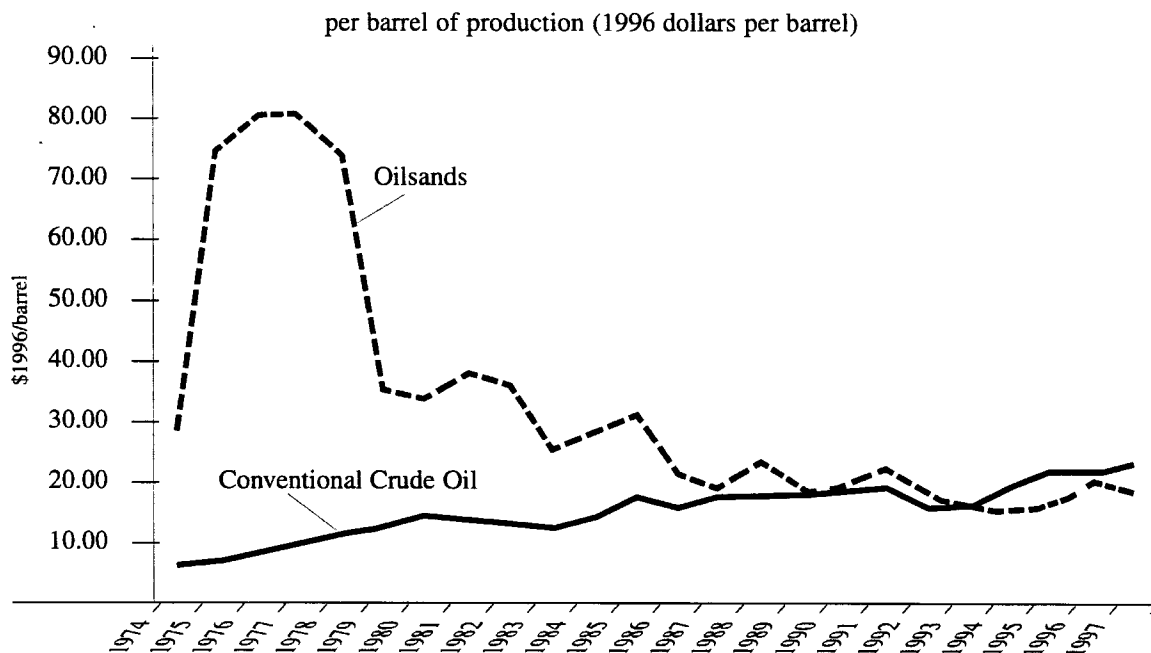
Year	Budget '99 forecast conventional crude oil royalties (\$/barrel)	Budget '99 forecast oilsands crude oil royalties (\$/barrel)
1996-97	4.07	2.93
1997-98	2.70	0.81
1998-99		1.20
1999-2000	1.04	0.19
2000-2001	1.23	0.14
2001-2002	1.24	0.08

The growing gap between conventional crude royalties per barrel and oilsands royalties is more problematic when considering that oilsands production and capital costs are comparable if not lower than conventional crude oil production costs. Figure 2, based on industry cost data, shows that real oilsands production and capital expenditures per barrel produced are actually lower than conventional crude oil production (operating, exploration, and development) costs. Conventional crude oil production costs are trending upwards as less productive oil reserves are extracted, while the economies of scale of oilsands mining are now being realized.

No wonder the British *Energy Economist* described Alberta's generic oilsands

royalty regime as "canny" with "the benefits substantial." By most accounting conventions used for resource industries and public utilities, the treatment of capital in the case of oilsands is generous. The current and future costs in terms of royalties foregone amount to millions of dollars over the next 10 to 15 years of oilsands development. The question for Albertans is why, under the circumstances and given the evidence, would we forego millions from our most important nonrenewable natural legacy?

Conventional crude oil vs. oilsands operating and capital expenditures



In conclusion, despite soaring oil prices in the third quarter of 1999, the picture painted in our original analysis has not changed. While oil royalty revenues can be expected to rise, almost doubling, in accordance with the oil price increase, Albertans are expected to earn significantly less than they would have in the past, under similar price conditions.

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Appendix I *Resource Development and Economic Rent: Theory and Application*

Resource development in Canada has traditionally been characterized by generous incentives to develop regional economies, including government financing of infrastructure, job creation, loan guarantees and liberal resource rent collection policies. Aitken (1959), a prominent economic historian characterized economic policy as the "promotion of economic growth by subsidized infrastructure and unrestricted access to natural resources" (Gunton and Richards, 1987). Such policies have been justified on the basis of encouraging the development of industries including agriculture, mining, petroleum and forestry. The development of Alberta's oil and gas industry has been no exception to this rule.

Many would argue that the policy history in natural resource development in Canada has been often at odds with widely accepted economic theory. The notion of economic rent in relation to scarce natural resources is long established in economics. The following discussion is designed to provide a brief background of economic rent in theory, as well as to introduce the reader to some of the many challenges facing policy makers in their attempts to collect economic rent in the real world.

A brief background on economic rent

Economic rent is the basis behind royalty collection in the oil and gas industry. David Ricardo (1817) defined economic rent as "that produce of the earth which is paid to the landlord for the original and indestructible powers of the soil." Another definition is the net revenue or surplus that remains after the revenues from natural resource extraction have been disbursed to pay all costs of production – including a normal rate of return for capital, labor and materials. In principle, the government, as owner and steward of the public resource, is entitled to collect the full economic rent. In practice, however, rents are usually distributed amongst government and industry, primarily because rents are difficult to determine and full rent collection by government may actually discourage industry production and investment in the long term.

Efforts to collect royalties are based on the idea that oil and gas are valuable resources, which in the vast majority of cases, are publicly owned. Constitutionally, the provinces are the owners of the resources within their boundaries and thus Albertans should be assured of the best possible return

(Gunton and Richards, 1987). Put another way, they represent valuable assets owned by all Albertans. As "landlord" of these resources, Albertans are due compensation from a company that has received exclusive rights to extract a certain portion of our valuable natural assets. A convenient way to view resource rents is that they are the result of free gifts of nature in the form of scarce natural resources.

In more concrete terms, economic rent refers to the difference between the sales value of oil and gas, and the costs to the company in looking for, developing, and extracting the resource. Of course the costs do not include anything related to the creation of oil or gas. The oil and gas was always there, as a gift of nature, which all Albertans were fortunate in having inherited as part of our portfolio of valuable assets. The difference between revenues from sales and costs, can be thought of in terms of the profits resulting from the production of resources. The challenge then, lies in determining the amount of these profits (rents) which go to oil and gas companies, and the amount that goes to Albertans as landowners of the resources.

Producers require a necessary return on their investments of capital, labor, and materials. They must effectively pay for the opportunity costs – the profits that would have been earned had they invested their money in other enterprises. For example, the money which goes to investments in oil and gas production could have been invested in an enterprise with a similar level of risk, such as the stock market, and achieved a certain level of profits. Seen this way, economic rent is the profits left over, after including both the explicit extraction costs, and the necessary return to "pay" for the opportunity costs of the investment.

The "extra profits" or net revenues over and above the amount necessary to justify the investment may be thought of as economic rent. As owner of the oil and gas resources, Albertans have a right to a large share, if not all, of the resulting rent. The reality of economic rent collection is that some may go to the company shareholders, or to company employees in higher wages. That a company receives some of the rent is not inherently a bad thing, however, it still represents foregone royalties that would have otherwise gone to the landlord of the resource (Albertans).

In the hands of the landlord, extra profits could be a means to finance services such as health care or education. These profits could also be used fund investments designed to contribute to the current and future prosperity of Albertans.

Oil and natural gas are gifts of nature which are non-renewable. As such, there may also be a desire to put at least some of the resource rents into a fund which ensures that after the gifts are effectively used up, our descendants are also able to reap some of the benefits. This is of particular importance, when we consider that some of the gifts which contribute to our natural wealth as Albertans, will have been spoken for long before our descendants have a voice in their use.

Some authors have also suggested that foregone rents can also lead to significant inefficiencies within the industry. Gunton and Richards note that "failure to collect rent can act as a subsidy which distorts both prices and hence a firm's production decision. The subsidy allows firms to earn normal returns without due regard for costs and to retain within the sector the income that could more productively be invested elsewhere." The authors further note that aggressive rent collection by the government can actually improve efficiency of industry and consequently the amount of rent generated.

The actual collection of rent presents many challenges, which will be discussed below. The challenges and limitations in actual rent collection, however, do not detract from the fact that as landlords, we should seek to get the most from those gifts of nature that have been bestowed upon us.

Rent Collection in Practice

Estimating economic rents is complex. It requires accurate data on prices, production costs, and capital costs. The complex nature of the oil and gas sector makes the government's task assessing and collecting rents a difficult one. In practice, governments use a variety of techniques to collect rents, including intensive bargaining and negotiating with industry to determine what is a fair share of the resource rents generated.

The absence of complete information upon which to estimate rents hinders the government, and thus makes efficient rent collection extremely difficult. Cost data of firms is not freely available to government, nor is there a legal requirement that requires firms to report their cost information. This is generally the case in all countries. Without such information, governments have several options. One is to estimate average industry rents and attempt to collect this rent through a royalty and other tax structures. Governments may also attempt

to discern industry costs by participating directly in the industry through a government agency or crown corporation, such as in the case of Norway through Statoil. Government may also simply levy a royalty tax based on the value of production. Finally, some governments, including Alberta, may combine a resource rent sensitive royalty tax along with ex ante bonus bidding for the rights of access to resources. Regardless, governments are ultimately at a disadvantage in negotiating resource rent collection regimes since industry maintains confidential cost data for reasons of competition.

A government must rely on the best cost and revenue data available on the industry operating in their jurisdiction. The only way to determine whether a government is collecting a fair share of a diffusely defined resource rents is to test the industry's willingness to accept certain royalty or other rent collection regimes. Testing the industry's willingness to pay a portion of the rent in the form of royalties is only determined through continuous negotiation and bargaining.

In the case of Alberta, the government's efforts to discern energy rents available is hampered by access to industry cost information. Government must rely, as we did in our analysis, on data that is publicly available, including cost data reported by the industry itself through the Canadian Association of Petroleum Producers. The alternative would be to legislate a requirement by industry to report their cost data to an independent auditor who would provide, in confidence, aggregate industry cost data to discern both average and marginal costs of production and a reasonable allowance for returns on capital.

When dealing with Alberta alone, it may be possible to compare rent collection over time to discern how efficient the current government is at collecting rents compared to previous administration. Such an analysis should be sensitive to changes in the conditions of the industry, prices, costs of production, capital costs, and other factors.

Another way to determine whether the province is doing a reasonable job at rent collection is to compare Alberta with other countries that are producing oil and gas under comparable conditions. In our analysis, we compared Alberta with Norway and Alaska. Direct comparisons are complicated by differences in the nature of the resource (North sea oil in Norway, versus oil sands and conventional crude oil in Alberta), operating conditions, prices and costs of capital. Nevertheless, comparisons are possible on the basis of royalties and taxes collected per value and production volume of oil and gas, remaining sen-

sitive to differences in market value and product costs. International rent collection benchmarks of this fashion provide a rough yet relevant reference point or "mirror" in which Alberta can be compared with others.

Somewhat ironically, the only measure of rent collection is the actual royalties and other taxes collected by the government. There is no requirement on the part of the government to account for the actual rent calculation upon which it theoretically levies royalties to collect a portion. The only way to estimate these rents is to construct a rent equation using what scant publicly available sales, production, exploration, development and capital costs which exist for the industry. We are dependent on only one source of data, the Canadian Association of Petroleum Producers statistical handbook, which provides industry aggregate value of production and cost data. Unfortunately, this aggregation makes it extremely difficult to assess rents specific to natural gas production versus conventional crude oil production, because of the fashion in which the data is reported. This ultimately hinders the reliability of our economic rent analysis. Without transparent figures from the government, our estimates are best guesses based on a single data source, namely, the industry.

The specific distribution of rent between the landowner (in our case the government of Alberta), and the company investing in the oil extraction is a complex issue which should be subject to intense public scrutiny. Nevertheless, there is general support for the notion that a government should attempt to collect as much of the extra profits as possible. While a detailed treatment of economic rent collection is beyond the scope of this paper, a brief overview of some of the relevant issues will provide some necessary background for further steps in the analysis. Some of the key issues to consider when considering resource rent analysis are as follows:

Uncertainty about costs: Estimating economic rent requires complete knowledge of both revenues (value of sales) and costs of production, including capital costs. In order for government to be efficient rent collectors, they must have access to industry cost data. However, for numerous reasons, including issues of competition, industry is reluctant to share cost information. As such, there is always some uncertainty on the cost side of the equation, which complicates rent collection efforts.

"Gold plating": The "gold plating" argument is based on the idea that if the rent take is too high, there will be little incentive for the company to invest in cost reduction or innovation. Gold plating of operating and capital expendi-

tures can also occur if cost deduction allowances in the determination of rent are too generous. Moreover, at very high rates of rent collection, the company may have incentives to spend additional net revenues rather than hand them over as royalties.

Incentives to investment: A key component of all rent collection initiatives is the requirement that they remain neutral. In other words, the investment decisions should not be affected by the chosen method of rent collection.

The dynamics of negotiations: Some commentators have stressed the ebb and flow in the bargaining power of governments and industry as being a major factor in the amount of the rent that governments can effectively capture in practice. In this light, the government may want to capture as much rent as possible, though not to the point where it discourages future investment.

While a fairly simple concept in theory, in reality, rent collection is a complex policy issue characterized in no small part by uncertainty. The complexity of rent collection may preclude a definitive answer to the question of efficient rent collection in Alberta. Nevertheless, the question of whether or not Albertans are receiving a reasonable rate of return on their valuable natural resource heritage is still of vital importance. Government is ultimately accountable to the citizens for demonstrating that it has exhausted the fullest extent of resource rent collection from public natural capital.

Resource Rent Studies

Resource rent collection studies were predominant during the latter days of the oil and gas price boom of the mid 1980s. Studies of Canadian resource rents by Thomas Gunton and John Richards (1987) and the international petroleum rent studies of Campbell Watkins and Alexander Kemp (1987) attest to the interest in resource rents at a time of a booming energy industry. Kemp & Watkins (1987), Smith (1992), Born (1992) and Anielski (1997) provided an important contribution to energy sector rent analysis for Alberta. Other than these few studies, there has been relatively little discussion in the energy economics literature since the collapse of oil and gas prices in 1986 despite considerable improvement in both natural gas and oil prices from 1992 to 1997.

Gunton and Richards' (1987) work on resource rents and public policy in Western Canada provides important insights into the resource rent issue. They conclude that Canada has traditionally done a poor job of assuring that citizens were receiving the full value of resource rents available to them from a rich endowment of natural capital.

Smith (1992) commented on the issue of whether the Alberta government exercised a savings rate (Solow's rule of thumb) of nonrenewable resource revenues in the Heritage Trust Fund that would yield a sustainable income stream when nature's capital was gone. He concluded that between 1963 and 1988, "the province was spending an amount from oil and gas revenues that may well have been inconsistent with maintenance of the stock of wealth over time." He noted that in 1988 alone, an additional \$1.9 billion should have been channeled into the Heritage Fund. With the collapse of oil prices in 1986, contributions to the Fund effectively ceased. Smith also estimated petroleum resource rents, using a rather liberal treatment of capital costs (fully expensing capital as if it were an annual operating cost, rather than adopting the accounting convention of amortizing these expenditures over the life of the manufactured capital or the life of the resource stock).

Anielski (1997) assessed the reserve life of existing stocks of oil and gas resources, as well as the resource rents generated, using Smith's liberal treatment of capital costs. Both the Smith and Anielski analyses suffered from reliance on a limited data set with only industry data available from the Canadian Association of Petroleum Producer's Statistical Handbook and Government of Alberta public accounts data. The lack of transparency in the industry cost data profile for conventional crude oil and natural gas production necessitated heroic assumptions about the allocation of production, exploration and development costs in the determination of resource rents. Precise estimates of resource rents are virtually precluded without access to accurate industry cost data. It is uncertain whether the Government itself has access to industry cost data. If so, it does not make such information public.

Appendix II *Tables and Data Sources*

Table 5

Alberta Oil, Gas, and Gas By-Products Production Summary Production Statistics (million m3 oe)

Year	Conventional Grude Oil	Synthetic & Bitumen Grude Oil	Natural Gas	Ethane	Butane	Pentane	Propane	Sulphur	TOTALS cubic meters millions	TOTALS barrels of oil equivalent (millions)
1962	26.3	-	17.5	-	-	-	-	-	43.8	275.3
1963	26.8	-	19.5	-	-	-	-	-	46.3	291.6
1964	27.8	-	24.4	-	-	-	-	-	52.3	328.8
1965	28.2	-	24.0	-	-	-	-	-	53.2	335.0
1966	32.2	-	25.4	-	-	-	-	-	57.6	362.4
1967	36.7	-	27.4	-	-	-	-	-	64.1	403.2
1968	40.0	-	31.0	-	-	-	-	-	71.0	448.9
1969	45.6	-	36.7	-	-	-	-	-	82.3	517.8
1970	52.4	-	42.9	0.0	2.1	6.8	3.2	4.3	111.7	702.7
1971	56.8	2.5	47.5	0.0	2.4	7.2	4.6	4.6	124.7	784.8
1972	67.5	3.0	52.2	0.0	3.0	9.4	4.6	6.6	146.3	920.8
1973	83.0	3.0	55.5	0.0	3.1	9.2	4.7	6.7	165.2	1,039.6
1974	78.1	2.7	56.8	0.5	3.2	9.2	4.9	6.9	163.4	1,028.0
1975	87.5	2.7	58.1	0.7	3.4	8.6	5.3	6.5	152.9	981.9
1976	60.8	3.3	59.5	0.5	3.4	7.5	5.1	6.2	146.3	920.7
1977	60.5	3.1	62.7	0.3	3.5	7.3	5.4	6.5	149.3	939.6
1978	60.0	3.7	61.7	0.5	3.2	6.6	5	6.3	147.0	925.0
1979	68.5	5.9	66.2	1.5	3.5	6.5	5.5	5.9	163.5	1,028.9
1980	63.2	8.0	62.1	3.6	3.3	5.9	5.3	5.7	157.1	988.5
1981	57.0	7.0	62.0	4.5	3.1	5.7	5.2	5.4	149.9	943.1
1982	54.4	7.3	64.1	4.7	3.1	5.6	5.2	5	149.4	940.0
1983	55.3	10.1	60.6	4.2	3	5.3	4.7	5.1	148.3	933.2
1984	59.9	9.7	65.6	4.7	3.1	5.5	5.1	5.1	158.9	1,000.1
1985	57.0	12.6	72.8	5.6	3.4	5.8	5.5	5	167.7	1,055.6
1986	53.1	16.1	64.9	5.8	2.8	5.8	4.7	4.9	158.2	985.4
1987	55.2	17.2	69.9	6.1	3	6.2	5	5	167.6	1,055.0
1988	57.7	19.2	81.0	7.1	3.3	6.4	5.6	5.1	185.4	1,166.4
1989	54.8	19.4	83.5	7.6	3.2	6.4	6	4.7	185.4	1,166.4
1990	53.0	19.9	89.3	7.3	3.2	6.3	6.4	4.8	190.2	1,197.1
1991	52.1	20.2	89.3	8.0	3.5	6.8	6.4	5	191.3	1,204.0
1992	53.2	21.1	88.9	8.3	3.7	6.8	6.7	5.2	203.9	1,283.1
1993	54.5	21.8	110.7	8.2	4.1	8	8	6	221.3	1,392.7
1994	55.2	23.0	117.6	9.0	3.9	8.1	6.3	6.4	229.5	1,444.2
1995	58.7	24.8	127.3	9.9	3.5	8.4	7.6	6.1	244.3	1,537.5
1996	54.8	28.1	131.0	10.9	3.6	8.7	7.8	6.2	251.0	1,579.7
1997	52.8	32.9	132.7	11.0	3.8	9.3	8.2	6.2	258.9	1,616.9
Totals	1,920.4	348.5	2,352.6	130.5	91.4	199.3	157.1	157.4	5,357.1	33,711.9

Source: Canadian Association of Petroleum Producers, Statistical Handbook, 1998

Note: Conversion from m3 oe to b.o.e. (barrels of oil equivalent) is 1 cubic meter = 6.29 barrels

Note: Natural gas production is marketable natural gas as opposed to raw natural gas. Figures for 1994-1997 are from the Alberta Energy Utilities Board. For example, in 1994 raw natural gas production was 141.4 million cubic meters versus marketable production of 118.6, or marketed gas was 84% of raw natural gas production by volume.

Table 6.

Value of Alberta Petroleum Industry Producers' Sales (\$ millions)

Year	Crude Oil & Condensate	Oil Sands **	Natural Gas	Pentanes Plus	Propane	Butane	Sulphur	Ethane	TOTAL
1962	388.5	-	78.9	23.1	4.1	2.3	8.3		505.1
1963	424.8	-	96.6	51.0	4.5	3.1	12.1		592.0
1964	450.3	-	113.2	60.2	5.9	5.9	16.8		652.4
1965	472.3	-	122.5	67.4	10.8	7.2	24.1		704.3
1966	522.7	-	135.5	71.1	15.8	9.7	37.2		791.9
1967	588.8	1.2	150.6	73.5	21.0	11.8	65.0		911.8
1968	644.7	15.7	171.0	84.0	21.7	13.3	76.3		1,026.8
1969	712.6	27.8	200.4	97.6	21.3	13.1	58.9		1,131.6
1970	844.1	32.8	243.9	114.4	26.9	15.0	27.4		1,304.5
1971	1,011.8	48.9	266.3	130.8	35.0	19.4	19.3		1,529.4
1972	1,210.5	62.3	307.3	173.3	44.1	26.5	17.7		1,841.7
1973	1,822.5	72.2	367.6	222.9	78.6	41.0	22.8		2,627.7
1974	2,878.9	108.9	594.3	352.5	177.1	108.4	67.5		4,287.6
1975	3,086.7	123.4	1,267.2	395.1	220.5	144.4	86.2		5,323.4
1976	3,262.1	162.3	2,101.0	403.1	233.3	171.1	69.3		6,402.2
1977	3,895.2	207.7	2,863.0	481.1	284.3	211.5	79.3		8,021.9
1978	4,617.3	297.5	3,241.4	513.2	260.1	198.7	99.6		9,227.8
1979	5,693.2	792.1	3,962.7	545.9	345.8	319.7	155.3		11,814.6
1980	6,185.1	1,716.6	5,121.1	586.2	466.3	423.3	433.6		14,932.3
1981	6,744.6	1,548.4	5,401.5	677.7	530.3	478.9	626.1		16,007.5
1982	8,800.4	2,072.5	6,046.4	885.9	492.6	524.2	551.4		19,373.4
1983	11,099.8	2,625.8	6,082.6	1,021.9	575.9	551.1	406.6		22,353.8
1984	12,601.9	2,385.3	6,923.8	1,123.0	661.7	580.9	582.9		24,759.5
1985	12,897.6	2,806.5	7,212.1	1,229.0	613.4	511.8	677.2		25,947.6
1986	6,268.1	1,710.0	5,048.9	709.4	405.4	297.4	683.2	331.4	15,453.8
1987	7,846.8	2,203.5	4,195.3	872.9	316.5	320.4	596.1	309.7	16,661.3
1988	6,087.8	1,696.1	4,373.6	700.0	286.9	260.2	583.1	312.6	14,300.3
1989	6,896.7	2,161.1	4,572.1	860.6	307.2	201.1	396.7	213.1	15,608.7
1990	8,209.9	2,799.3	4,667.0	1,061.8	564.3	332.3	368.1	351.6	18,354.3
1991	6,632.9	2,254.6	4,343.8	926.3	501.3	347.5	329.5	340.8	15,676.6
1992	6,834.7	2,362.2	4,812.5	1,018.3	499.3	332.9	100.4	387.4	16,347.7
1993	6,428.5	2,376.5	6,648.3	1,081.9	710.4	366.6	(7.7)	559.1	18,163.5
1994	6,868.2	2,672.1	8,091.1	1,178.1	614.1	371.6	77.8	491.8	20,364.8
1995	7,579.3	3,257.3	6,200.0	1,423.3	797.8	433.1	149.2	716.7	20,556.6
1996	9,124.5	4,033.1	7,759.7	1,865.9	1,306.1	544.4	76.5	733.5	25,463.7
1997	7,995.1	4,037.3	9,454.9	2,114.6	993.9	486.6	73.9	761.3	25,917.6
Totals	177,619	46,669	123,138	23,217	12,454	8,686	7,648	5,509	404,940

Source: Canadian Association of Petroleum Producers (1998) Statistical Handbook Table 4.17a and 4.17b

Does not include experimental crude and ethane until 1986. Experimental crude oil included with crude oil in 1986.

** does not represent the true value of all synthetic crude oil

Table 7

Net Cash Expenditures of the Alberta Petroleum Industry

(Does not include oil sands expenditures)

Million Dollars

	Exploration	Development *	Operating	Total Expenditures	Govt. Royalties & Fees
1962	177.5	143.6	109.0	430.1	130.0
1963	184.2	172.6	123.5	480.3	158.0
1964	239.0	171.8	131.0	541.8	213.0
1965	309.7	188.0	136.7	634.4	257.0
1966	313.8	178.8	144.9	637.5	250.0
1967	330.0	240.8	162.2	733.0	230.0
1968	349.0	246.5	179.5	775.0	294.0
1969	355.8	270.6	196.4	822.8	267.0
1970	280.7	327.7	219.5	827.9	235.0
1971	272.2	376.1	276.4	924.7	274.0
1972	297.7	333.0	323.8	954.5	333.0
1973	346.4	350.7	388.5	1,085.6	612.4
1974	416.2	455.4	488.4	1,360.0	1,926.7
1975	456.0	562.0	640.2	1,658.2	1,932.9
1976	657.5	845.6	826.1	2,329.2	2,158.5
1977	1,298.0	861.2	910.9	3,070.1	2,252.7
1978	1,735.3	1,129.2	1,103.4	3,967.9	2,993.2
1979	2,521.9	1,538.3	1,373.4	5,433.6	3,357.2
1980	3,250.4	2,340.7	1,679.2	7,270.3	4,593.0
1981	2,617.2	2,418.3	1,834.5	6,870.0	4,623.0
1982	1,867.0	2,408.2	2,185.3	6,460.5	3,309.0
1983	1,955.2	1,801.4	2,431.8	6,188.4	4,307.0
1984	2,392.8	2,136.0	3,137.1	7,665.9	4,694.0
1985	2,869.9	2,879.9	3,645.9	9,395.7	4,339.0
1986	1,917.5	2,246.5	3,674.5	7,838.5	1,573.0
1987	2,271.9	2,037.1	3,494.3	7,803.3	2,467.0
1988	2,286.8	2,729.1	3,919.3	8,935.2	1,990.0
1989	1,818.2	2,418.6	4,375.3	8,612.1	2,149.0
1990	2,016.4	2,566.7	4,445.4	9,028.5	2,574.4
1991	1,714.5	2,967.9	4,753.9	9,436.3	1,922.0
1992	1,249.4	2,415.3	4,524.7	8,189.4	2,064.6
1993	1,958.2	3,619.8	4,643.0	10,221.0	2,699.0
1994	3,346.5	5,304.9	4,874.0	13,525.4	3,249.0
1995	2,909.6	5,435.5	4,852.6	13,197.7	2,647.0
1996	3,172.1	5,195.2	5,033.3	13,400.6	3,884.5
1997	3,855.5	7,814.3	4,922.0	16,591.8	3,611.7

Source: Canadian Association of Petroleum Producers Statistical Handbook (1996) Table 4.3b

Exploration costs include geological & geophysical, drilling, land acquisitions and rentals and others

Development costs include drilling, field equipment, secondary recovery & pressure maintenance, natural gas plants, and other.

Operating costs include wells including flow lines and related facilities, natural gas plants, taxes (excluding income tax), and other

* Before P.I.P. grants; ** Net of incentive credits where applicable.

Royalties reported in CAPP Table 4.3b are net of incentive credits

Expenditures exclude oilsands expenditure which are shown in Table 14a+A24

Table 8

Alberta (Canada) Oil Sands Expenditures

Million Dollars

	Capital Expenditures	Operating Costs	Subtotal
1962	25.0	-	25.0
1963	40.5	-	40.5
1964	80.4	-	80.4
1965	81.6	-	81.6
1966	131.5	-	131.5
1967	72.5	-	72.5
1968	38.8	9.5	48.3
1969	16.9	36.7	53.6
1970	24.8	36.3	61.1
1971	26.9	46.5	73.4
1972	13.7	48.7	62.4
1973	27.5	60.7	88.2
1974	102.0	76.9	178.9
1975	442.5	90.6	533.1
1976	623.0	144.6	767.6
1977	550.3	251.0	801.3
1978	399.8	550.3	950.1
1979	245.2	540.0	785.2
1980	430.5	771.3	1,201.8
1981	541.1	756.0	1,297.1
1982	386.1	1,051.5	1,437.6
1983	422.6	1,048.2	1,470.8
1984	510.3	1,064.3	1,574.6
1985	1,131.5	1,225.6	2,357.1
1986	612.8	1,208.3	1,821.1
1987	539.5	1,146.7	1,686.2
1988	863.6	1,483.0	2,346.6
1989	422.4	1,515.3	1,937.7
1990	730.7	1,539.4	2,270.1
1991	1,090.5	1,544.1	2,634.6
1992	639.1	1,579.2	2,218.3
1993	340.8	1,636.3	1,977.1
1994	272.6	1,787.7	2,060.3
1995	571.9	1,859.7	2,431.6
1996	1,286.3	2,132.6	3,418.9
1997	1,914.5	1,845.5	3,760.0

Source: Canadian Association of Petroleum Producers. Statistical Handbook -1998

Table 9

Alberta Government, Natural Resource Revenue (millions of dollars)

Years Ended March 31 1974 to 1998

Fiscal yr	Calendar year	Oilseeds				Bonuses & Sale of Crown Leases	Gross Non-renewable Resource Revenues	Credits	Royalty Tax Credit	Total Credits	Net Non-Renewable Energy Revenue (net of credits)	Net Oil and Gas		Oil & Gas Revenues (1998 constant dollars)
		Conventional Crude Oil	Bitumen & Heavy Crude	N. Gas & Byproducts	Coal & Rentals and fees							Energy Revenues (less coal, rental & fees)	Oil & Gas Revenues (1998 constant dollars)	
1961														
1962														
1963	1962													
1964	1963													
1965	1964													
1966	1965													
1967	1966													
1968	1967													
1969	1968													
1970	1969													
1971	1970													
1972	1971													
1973	1972													
1974	1973	302.1	6.2	302.1										
1975	1974	956.4	13.9	956.4										
1976	1975	975.4	15.4	975.4										
1977	1976	1,094.3	16.1	1,094.3										
1978	1977	1,323.2	23.8	1,323.2										
1979	1978	1,775.7	30.8	1,775.7										
1980	1979	1,999.9	46.2	1,999.9										
1981	1980	1,969.0	226.0	1,969.0	102.0									
1982	1981	2,176.0	230.0	1,956.0	115.0									
1983	1982	2,336.0	362.0	1,974.0	116.0									
1984	1983	2,973.0	304.0	1,994.0	102.0									
1985	1984	2,916.0	135.0	1,942.0	97.0									
1986	1985	2,534.0	221.0	1,906.0	102.0									
1987	1986	997.0	12.0	1,097.0	86.0									
1988	1987	1,320.0	23.0	1,097.0	85.0									
1989	1988	933.0	19.0	989.0	92.0									
1990	1989	1,126.0	28.0	961.0	92.0									
1991	1990	1,326.0	39.0	1,080.0	113.0									
1992	1991	1,023.0	27.0	892.0	120.0									
1993	1992	1,008.5	64.9	1,069.3	116.5									
1994	1993	787.0	67.0	1,410.0	119.0									
1995	1994	1,097.0	223.0	1,242.0	129.0									
1996	1995	1,047.0	312.0	1,004.0	138.0									
1997	1996	1,306.3	512.0	1,299.4	149.5									
1998	1997	914.0	192.0	1,660.0	166.3									
Forecast 1998/1999	1998	844.0	63.0	1,426.0	160.0									
Forecast 1999/2000	1999	346.0	43.0	1,695.0	158.0									
Forecast 2000/2001	2000	410.0	33.0	1,672.0	157.0									
Forecast 2001/2002	2001	413.0	22.0	1,904.0	162.0									
TOTALS		37,901.7	3,314.1	38,705.9	2,681.3	12,433.3	95,049.0	3,759.6	7,019.6	10,779.2	84,269.9	81,586.5	104,399.9	

Source: Alberta Public Accounts, various years. Total revenue figures are from General Revenue Fund figures prior to 1980-81; thereafter shown on consolidated fiscal basis as per Budget '97 (p. 50).

Note: Royalty holidays and other credits do not appear in the Public Accounts but are shown netted out of non-renewable resource revenues.

We are uncertain what these additional credits to industry amount to, however, some discussions with government officials suggests that these benefits might amount to as much as the royalty tax credit for 1995.

Figures for 1961-1973 are from Statistics Canada, Provincial Government Finances: Revenues and Expenditures (Ottawa: Statistics Canada, various years) 68-207 and 68-207a.

Mineral Freehold Taxes are payments by landowners with rights of access to sub-surface resources; the tax is levied on the landowner to recapture part

of the premium paid by oil and gas companies for the right to access petroleum resources. The Crown simply recovers part of the resource rent through this fashion.

(2) Federal corporate tax payable is estimated based on the basis that federal tax rate is 28% of taxable income plus 4% surtax, Alberta's corporate tax rate is 15.5% of taxable income

Therefore, the ratio of federal tax to provincial tax is 2.06 times the provincial corporate tax payable.

Table 10

Norway Data Set

	Production			Norwegian Government Oil and Gas Revenues (billions of NOK, 1996 constant value)										Norwegian Oil and Gas Revenues Oil and Gas Revenue In 1996 Cdn dollars per boe (1993 Cdn)		Had Alberta received the Norway Energy Rent Collection Rate \$ millions, 1996 Cdn	
	Crude Oil million m3 oe	Natural Gas million m3 oe	NGL Cond. million m3 oe	TOTAL million m3 oe	TOTAL million boe	Corporate tax	Special Profit (Rent) Tax	Royalties	Area Fee	Carbon tax	Subtotal	SDF	Total (incl SDF)	Exchange Rates \$102m-Krone	Total Norwegian Oil and Gas Revenue In 1996 Cdn dollars	Oil and Gas Revenues per boe (1993 Cdn)	Had Alberta received the Norway Energy Rent Collection Rate \$ millions, 1996 Cdn
1985	44.6	26.2	2.0	72.8	459.7	34.00	20.29	10.12	0.34	-	72.75	(27.16)	45.59	6.43	6,396	16.30	19,322
1986	46.8	26.1	2.0	74.9	487.4	25.17	14.54	11.88	0.29	-	51.88	(17.39)	34.49	6.43	6,423	13.18	13,117
1987	57.0	26.2	2.6	87.9	553.0	9.54	4.26	10.65	0.32	-	24.17	(14.32)	9.85	4.78	2,058	3.72	5,973
1988	64.7	26.3	3.3	98.4	608.1	6.43	1.34	6.87	0.23	-	14.87	(11.43)	3.42	5.52	870	1.02	1,192
1989	66.0	26.7	3.3	116.0	743.5	5.79	1.85	6.74	0.27	-	16.65	0.80	17.55	5.71	3,074	4.14	4,828
1990	64.5	25.5	3.4	123.4	776.4	14.24	5.72	9.78	0.30	-	30.02	8.48	38.48	5.09	7,560	9.74	11,656
1991	108.5	25.0	3.3	136.8	860.8	18.73	7.50	9.86	0.65	0.80	35.74	6.55	42.29	5.17	8,180	9.50	11,441
1992	124.0	25.8	3.4	153.2	983.6	8.22	7.91	8.35	0.59	2.08	27.73	3.84	31.67	5.48	6,800	6.07	7,723
1993	131.8	24.8	4.2	160.8	1,011.4	8.82	10.14	8.35	0.59	2.42	28.32	0.17	28.49	5.68	5,034	4.98	6,931
1994	148.3	26.8	7.1	180.3	1,133.9	8.54	9.41	6.92	0.15	2.69	25.70	0.01	25.71	4.82	5,334	4.70	6,764
1995	156.8	27.6	8.4	192.9	1,213.2	8.16	11.03	6.02	0.56	2.82	28.38	7.44	35.80	4.63	8,315	6.85	10,538
1996	175.5	37.4	9.2	222.1	1,397.2	6.70	8.00	6.30	1.00	3.00	25.80	22.80	47.90	4.70	10,192	7.29	11,623
1997	183.3	43.6	10.7	238.0	1,484.4	n.a.	n.a.	n.a.	n.a.	n.a.	34.80	58.00	65.10	5.10	12,765	8.80	13,903
2000 (forecast)	186.0	55.0	12.0	253.0	1,654.3	n.a.	n.a.	n.a.	n.a.	n.a.	42.00	58.00	100.00	5.00	20,000	12.08	23,148
Average (1992-97)	152.9	30.9	7.2	190.9	1,203.7	7.3	9.30	7.29	0.59	2.58	28.34	10.78	39.58	5.41	7,907	6.41	9,559
Total 1992-1997	917.5	165.3	43.1	1,145.3	7,203.7	36.4	48.5	36.4	3.0	12.8	170.0	64.7	237.4		47,440		67,413

Source: Statistics Norway, Ministry of Industry (figures for 1985-1996) and Energy and Ministry of Finance (figures for 1997 and 2000)

http://econ.dep.no/norim/industrial/energy/industrial/industrial_0001.htmexchange rate information: http://www.ssb.no/norim/energy/energy/energy/energy_0001.htm

Notes: SDF (state's direct financial interest) through Statoil, Norway's national energy company.

n.a. - not available

Table 11

Alaska Data Set

	Production		Revenues						
	Crude Oil million barrels	Natural Gas (net marketable) billion cubic feet	Oil, Gas and Byproduct Production million barrels of oil equivalent	Total Petroleum Revenue US \$ millions	Royalties (oil and gas) US \$ millions	Petroleum Revenues		US/Cdn dollar exchange rate	Alaska average crude oil wellhead price per barrel US\$/barrel
						per b.o.e equivalent production US\$	per b.o.e equivalent production Cdn \$1996		
1977	171.4	189.3	205.6	477.8	36.3	2.32	4.86	1.063	6.14
1978	447.8	216.1	487.1	441.5	150.6	0.91	1.87	1.141	5.23
1979	511.5	228.0	552.7	821.8	250.2	1.49	2.87	1.171	10.25
1980	591.6	230.9	633.5	2,256.5	689.4	3.56	5.87	1.169	16.52
1981	587.3	247.2	632.4	3,304.3	1,119.7	5.23	8.03	1.199	23.8
1982	618.9	261.9	666.6	3,574.8	1,174.4	5.36	7.56	1.234	20.08
1983	625.6	283.1	676.7	3,026.6	1,105.6	4.47	5.91	1.232	17.92
1984	630.4	300.7	684.7	2,861.6	1,058.5	4.18	5.74	1.295	18.13
1985	686.6	328.6	726.2	2,743.5	1,042.2	3.78	5.32	1.366	17.12
1986	681.6	314.7	739.3	2,657.4	845.0	3.59	5.83	1.389	8.71
1987	715.7	380.7	786.6	1,394.5	448.3	1.75	2.72	1.326	10.83
1988	738.6	400.4	831.1	1,949.8	701.5	2.35	3.46	1.231	8.43
1989	684.6	403.9	775.5	1,840.4	611.5	2.37	3.21	1.184	11.93
1990	847.5	412.1	736.1	2,121.3	753.7	2.87	3.54	1.167	15.6
1991	858.4	442.3	759.1	2,571.8	956.7	3.39	4.11	1.146	10.16
1992	627.3	445.9	733.7	2,007.4	708.2	2.74	3.50	1.209	10.95
1993	577.9	456.4	686.1	1,967.8	716.7	2.87	3.93	1.286	10.81
1994	569.0	469.5	678.5	1,292.7	516.1	1.91	2.76	1.387	9.87
1995	541.6	482.2	657.2	1,617.2	631.8	2.46	3.63	1.413	11.24
1996	510.8	490.6	631.4	1,684.8	642.2	2.84	3.78	1.427	15.07
1997	473.0	478.2	593.1	2,010.2	759.2	3.39	4.83	1.441	14.84
1998	n.a.	n.a.	n.a.	1,332.8	480.4				
average 92-97	549.9	470.6	663.3	1,760.0	662.4	2.67	3.74	1.36	12.15

Sources: Energy Information Administration/Annual Energy Review 1997;
Revenue Sources Book Forecast and Historical Data, State of Alaska, Department of Revenues

Table 11.2

Norwegian									
Resource Rents Collected: Royalties and Taxes									
(millions Cdn\$, 1998 values)									
	Corporate tax	Special Tax	Profit	Royalties	Area Fee	Carbon tax	Subtotal	SDFI Net Cash Flow	Total (incl. SDFI)
1985	6,281.51	3,738.65	3,337.02	82.62	-	-	13,397.79	(5,001.84)	8,395.95
1986	4,687.15	2,707.84	2,212.29	54.00	-	-	9,661.08	(3,238.36)	6,422.72
1987	1,991.65	889.35	2,098.12	66.81	-	-	5,045.93	(2,989.56)	2,056.37
1988	1,164.88	242.75	1,244.57	41.67	-	-	2,693.84	(2,074.28)	619.57
1989	1,014.01	323.99	1,530.65	47.29	-	-	2,915.94	157.62	3,073.58
1990	2,797.84	1,123.77	1,917.49	58.94	-	-	5,897.84	1,662.08	7,559.92
1991	3,235.98	1,450.68	1,928.50	125.73	174.08	-	6,912.96	1,266.82	8,179.88
1992	1,505.48	1,448.72	1,620.88	122.71	380.95	-	5,078.75	721.61	5,800.37
1993	1,204.95	1,791.52	1,475.27	104.24	427.58	-	5,003.53	30.04	5,033.57
1994	1,358.65	1,952.28	1,435.68	31.12	558.02	-	5,331.95	2.07	5,334.02
1995	1,762.42	2,382.29	1,300.22	120.95	565.87	-	6,131.75	1,606.91	8,315.33
1996	1,425.53	1,702.13	1,340.64	212.77	638.30	-	5,319.38	4,872.34	10,191.70
1997 -	-	-	-	-	-	-	6,843.14	5,921.57	12,764.71

Note: 1997 tax revenue details were not available though gross figures were.

Table 11.3

Norway									
Resource Rents Collected: Royalties and Taxes									
(millions Cdn\$/boe produced, 1996 values)									
	Corporate tax	Special Profit Tax	Royalties	Area Fee	Carbon tax	Subtotal	SDFI Net Cash Flow	Total (incl. SDFI)	
1985	13.95	8.15	7.28	0.14	-	29.21	(10.90)	18.30	
1986	9.92	5.56	4.54	0.11	-	19.82	(6.64)	13.18	
1987	3.90	1.61	3.79	0.12	-	9.12	(5.41)	3.72	
1988	1.92	0.40	2.05	0.07	-	4.44	(3.42)	1.02	
1989	1.37	1.80	2.06	0.08	-	3.93	0.21	4.14	
1990	3.80	1.45	2.47	0.08	-	7.60	2.14	9.74	
1991	3.76	1.69	2.24	0.15	0.20	8.03	1.47	9.50	
1992	1.56	1.50	1.68	0.13	0.40	5.27	0.75	6.02	
1993	1.18	1.77	1.46	0.10	0.42	4.85	0.03	4.98	
1994	1.20	1.72	1.27	0.03	0.49	4.70	0.00	4.70	
1995	1.45	1.86	1.07	0.10	0.47	5.05	1.32	6.85	
1996	1.02	1.22	0.96	0.15	0.46	3.81	3.49	7.29	
1997						4.81	3.00	8.81	

average 1985-1992
average 1992-1997

Percentage of total revenues
average 1885-1992
average 1992-1997

Note: 1997 detail tax revenue statistics are not available

Sources: Statistics Norway, Ministry of Industry (figures for 1985-1996) and Energy and Ministry of Finance (figures for 1997 and 2000)

http://odin.dep.no/odin/hofoval/deptler/oe/publ/taekte/kap_0001.htm

Table 12

Comparison of Government Revenues from Petroleum Production

Cdn 1996\$ per boe

	Alberta	Alaska	Norway
1977	4.72	4.86	
1978	5.86	1.87	
1979	5.37	2.87	
1980	6.55	5.87	
1981	6.28	8.03	
1982	4.02	7.56	
1983	4.95	5.91	
1984	4.98	5.74	
1985	4.23	5.32	18.30
1986	1.84	5.83	13.18
1987	2.74	2.72	3.72
1988	2.04	3.46	1.02
1989	2.10	3.21	4.14
1990	2.28	3.54	9.74
1991	1.69	4.11	9.50
1992	1.70	3.50	6.02
1993	2.05	3.93	4.98
1994	2.35	2.76	4.70
1995	1.80	3.63	6.85
1996	2.46	3.76	7.29
1997	2.21	4.83	8.60
Forecast 1998/99-2001/02	1.19		12.09
averages (1992-97)	2.10	3.74	6.41

Source: calculated from various source tables

Table 13

Alberta Government: Budget '99

(current \$)	Conventional Crude Oil				Oilsands		Oilsands Royalties		Oilsands Royalties		Oil Royalties	
	Royalties \$ millions	Total Oil Productio barrels per day	barrels per annum million barrels	Alberta Wellhead \$/barrel	Royalties \$ millions	per barrel producti per barrel producti	per barrel producti	per barrel producti	per barrel producti	per barrel producti	per barrel producti	per barrel producti
96-97 actuals	1386	1,544	563.6	27.91	512	2.21	3.37					
1997-98 actuals	914	1,544	563.6	22.25	192	0.83	1.96					
1998-99 forecast	409	1,558	568.7	16.20	63	0.27	0.83					
1999-2000 forecast	346	1,531	558.8	15.92	43	0.19	0.70					
2000-2001 forecast	410	1,569	572.7	18.57	33	0.14	0.77					
2001-2002 forecast	413	1,647	601.2	19.99	22	0.08	0.72					
decline 2001 from 1996-97	-973	103	37.6	-7.92	-490	(2.13)	(2.64)					
% change	-70%	7%	7%	-28%	-96%	-96%	-79%					
	Natural Gas		Production		NG Production In		Estimated NG		Natural Gas price		Projected Total Oil, Gas &	
	Royalties \$ millions	billion cubic ft.	boe	byproducts	boe	C\$/mcf	byproducts	C\$/mcf	byproducts	C\$/mcf	million boe	million boe
96-97 actuals	1,299	4,865	886.52	225.30	1.77						1,655	1,655
1997-98 actuals	1,660	5,216	929.04	241.55	1.86						1,734	1,734
1998-99 forecast	1,426	5,355	953.80	247.99	1.97						1,770	1,770
1999-2000 forecast	1,695	5,748	1,023.80	266.19	2.02						1,849	1,849
2000-2001 forecast	1,672	5,980	1,085.12	278.93	1.93						1,915	1,915
2001-2002 forecast	1,904	6,278	1,118.20	290.73	2.01						2,010	2,010
decline 2001 from 1996-97	605	1,413	251.67	65.44	0.24						355	355
% change	47%	29%	29%	29%	14%						21%	21%
	Bonuses and sales of Crown leases		Royalty Tax Credit		Total Revenues (forecasts/estimates)		Oil, oilsands, natural gas revenues		Total Revenues (forecasts/estimates)		Oil, oilsands, natural gas revenues	
	\$ millions	\$ millions	\$ millions	\$ millions	\$ millions	\$ millions	\$ millions	\$ millions	\$ millions	\$ millions	\$ millions	\$ millions
96-97 actuals	927	-240	3,884	2.35								
1997-98 actuals	1,071	-225	3,612	2.08								
1998-99 forecast	448	-242	2,104	1.19								
1999-2000 forecast	430	-256	2,258	1.22								
2000-2001 forecast	470	-241	2,344	1.22								
2001-2002 forecast	570	-191	2,718	1.35								
decline 2001 from 1996-97	(357)	49	(1,166)	(0.99)								
% change	-38%	-20%	-30%	-42%								

Table 14

Toronto Stock Exchange '300' Total Return Index

(closing values)

	TSE Oil & Gas		TSE Oil and Gas		Dividends per year		Earnings (12 mths)	
	Total Return Index	Annual% change	Index	Annual% change	(\$,000)	Annual% change	(\$,000)	Annual% change
(TRI)								
1970	774		950					
1971	956	24%	1,159	22%				
1972	1,370	43%	1,643	42%				
1973	1,184	-14%	1,403	-15%				
1974	625	-47%	725	-48%				
1975	867	39%	979	35%				
1976	1,000	15%	1,097	12%				
1977	1,397	40%	1,489	36%	140,075		566,928	
1978	1,773	27%	1,846	24%	158,288	13%	641,135	13%
1979	3,653	106%	3,745	103%	163,308	3%	725,494	13%
1980	4,311	18%	4,358	16%	225,962	38%	1,109,627	53%
1981	3,707	-14%	3,697	-15%	215,518	-5%	833,703	-25%
1982	2,748	-26%	2,683	-27%	197,064	-9%	146,325	-82%
1983	3,642	33%	3,469	29%	183,643	-7%	163,917	12%
1984	3,197	-12%	2,990	-14%	73,537	-60%	420,584	157%
1985	3,606	13%	3,298	10%	281,505	283%	778,286	85%
1986	3,418	-5%	3,053	-7%	223,012	-21%	48,266	-94%
1987	3,736	9%	3,280	7%	245,645	10%	599,252	1142%
1988	4,204	13%	3,619	10%	238,226	-3%	555,929	-7%
1989	5,302	26%	4,475	24%	236,488	-1%	354,504	-36%
1990	4,794	-10%	3,973	-11%	248,528	5%	429,531	21%
1991	3,970	-17%	3,206	-19%	254,477	2%	27,547	-94%
1992	4,194	6%	3,327	4%	227,847	-10%	595,893	2063%
1993	5,658	35%	4,433	33%	278,851	22%	487,596	-18%
1994	5,304	-6%	4,117	-7%	299,232	7%	1,226,808	152%
1995	6,181	17%	4,748	15%	401,649	34%	1,185,315	-3%
1996	8,520	38%	6,487	37%	414,719	3%	1,579,316	33%
1997	8,824	4%	6,670	3%	463,463	12%	2,578,112	63%
1998	6,190	-30%	4,643	-30%	445,432	-4%	192,473	-93%
Change over	245%		202%		165%		331%	
% change	145%		102%		65%		231%	

Notes:

Total Return Index is a measure of the investment performance through time based on price appreciation but also due to the reinvestment of dividends. It is a more robust index than the TSE O&G stock price index

Source: "The Toronto Stock Exchange '300' Total Return Index"

Table 15

Exchange Rates & Conversion Factors

Exchange Rate (US/Cdn) US/Cdn Norway/Cdn\$

1972	0.991	1 Cdn = x Krone
1973	1.000	
1974	0.978	
1975	1.017	
1976	0.986	
1977	1.063	
1978	1.141	
1979	1.171	
1980	1.169	
1981	1.199	
1982	1.234	
1983	1.232	
1984	1.295	
1985	1.368	5.43
1986	1.389	5.37
1987	1.326	4.79
1988	1.231	5.52
1989	1.184	5.71
1990	1.167	5.09
1991	1.146	5.17
1992	1.209	5.46
1993	1.296	5.66
1994	1.387	4.82
1995	1.413	4.63
1996	1.427	4.70
1997	1.441	5.10
1998	1.434	

(source: Canadian Economic Observer)

Norwegian exchange rates are from:

<http://www.ssb.no/english/yearbook/1998/1511001.shtml>

Alberta GDP Implicit

Price Index

1986=100 1996=100

1972	28.9	24.8
1973	32.8	28.1
1974	42.8	36.7
1975	49.2	42.2
1976	55.0	47.1
1977	59.3	50.8
1978	64.5	55.3
1979	70.9	60.7
1980	82.8	70.9
1981	91.1	78.1
1982	102.2	87.6
1983	108.8	93.2
1984	110.1	94.3
1985	113.3	97.1
1986	100.0	85.7
1987	99.6	85.3
1988	97.4	83.5
1989	102.2	87.6
1990	110.3	94.5
1991	110.2	94.4
1992	110.2	94.4
1993	110.4	94.6
1994	111.6	95.6
1995	111.9	95.9
1996	116.7	100.0
1997	117.9	101.0
1998 (e)		102.5
1999 (e)		104.1
2000 (e)		105.6
2001 (e)		107.2

Source: Alberta Treasury, Statistics Unit

Note: 1997 and 1996 dollar deflators are derived from the 1986 GDP Implicit Price Index Deflator Series. Deflators for 1998-2001 are estimated assuming a 1.5% per annum increase in the GDP implicit price index deflator which is similar to the forecast CPI for Alberta (see Budget '99).

Norwegian Krona values

Volume conversions

	cubic feet	barrels	cubic meters
1 cubic foot	1.000	0.178	0.028
1 barrel	5.615	1.000	0.159
1 cubic meter	35.315	6.293	1.000

Source: Appendix E, Conversion Factors, Historical and Projected Oil and Gas Consumption, Alaska Dept. of Natural Resources, Oil and Gas Division

Table 16

Canadian Petroleum Industry reported taxes paid (corporate, municipal property, excludes royalties)

	Current Taxes (\$ millions)	Production boe (millions)	Current taxes per boe production current dollars	1996 dollars
1992	422	2,397	0.18	0.19
1993	507	2,813	0.18	0.19
1994	1,122	3,426	0.33	0.34
1995	1,086	4,223	0.26	0.27
1996	2,037	4,973	0.41	0.41
1997	2,537	5,291	0.48	0.47
average			0.31	0.31

Source: R. Moss, CFA, Canadian Petroleum Perspectives

based on sample of roughly 110 Canadian oil and gas companies

Consolidated Statement of Income and Retained Earnings

Table 17

International Oil Prices

(\$/bbl)

	Alberta Wellhead Price		North Sea Brent Sea Oil		Difference (Alberta-NorthSe	
	Cdn\$	US\$	US\$	Cdn\$	Cdn\$	%
1962	2.26					
1963	2.47					
1964	2.55					
1965	2.56					
1966	2.57					
1967	2.54					
1968	2.56					
1969	2.48					
1970	2.83					
1971	2.83					
1972	2.84	2.87	1.90	1.88	0.96	34%
1973	3.48	3.48	2.83	2.83	0.65	19%
1974	5.77	5.90	10.41	10.18	(4.41)	-76%
1975	7.25	7.13	12.80	13.02	(5.77)	-79%
1976	8.50	8.62	13.92	13.73	(5.23)	-62%
1977	10.21	9.60	14.02	14.90	(4.70)	-46%
1978	12.20	10.69	31.61	36.07	(23.87)	-196%
1979	13.18	11.25	36.61	42.87	(29.69)	-225%
1980	15.52	13.28	36.83	43.05	(27.53)	-177%
1981	18.78	15.66	35.93	43.08	(24.30)	-129%
1982	25.67	20.80	32.97	40.68	(15.02)	-59%
1983	31.80	25.81	29.55	36.41	(4.60)	-14%
1984	33.36	25.76	28.66	37.11	(3.75)	-11%
1985	34.06	24.93	27.51	37.58	(3.52)	-10%
1986	18.73	13.48	14.38	19.97	(1.24)	-7%
1987	22.57	17.02	18.43	24.44	(1.87)	-8%
1988	16.75	13.60	14.96	18.42	(1.67)	-10%
1989	20.01	16.90	18.20	21.55	(1.54)	-8%
1990	24.57	21.05	23.81	27.79	(3.22)	-13%
1991	20.17	17.60	20.05	22.98	(2.80)	-14%
1992	20.35	16.83	19.37	23.42	(3.07)	-15%
1993	18.65	14.39	17.07	22.12	(3.47)	-19%
1994	19.68	14.19	15.98	22.16	(2.49)	-13%
1995	21.63	15.31	17.24	24.36	(2.74)	-13%
1996	26.31	18.44	21.00	29.97	(3.66)	-14%
1997	23.88	16.57	19.00	27.38	(3.50)	-15%
1998	16.20	11.30				
1999	15.92					
2000	18.57					
2001	19.99					
Lougheed (71-85)	15.90	13.27	22.54	26.67	(10.77)	-74%
Getty (86-92)	20.45	16.64	18.46	22.65	(2.20)	-11%
Klein (92-97)	21.75	15.95	18.28	24.90	(3.15)	-15%

Born (1992) Alberta Oil and Gas Resource Rent Estimates

Source: Born, Alice. 1992. Development of Natural Resource Accounts: Physical and Monetary Accounts for Crude Oil and Natural Gas Reserves in Alberta. Statistics Canada.

Table 19

Oil and Gas Rent Analysis and Estimates - Details (in Constant 1996 Dollars)

Market Value of Petroleum Sales	Rent Estimates		Born	Anielski (1997) (conv. crude oil and nat. gas only) 1962-97	Born estimates (conv. Oil and NG only) 1962-97	Born estimates for total industry	Net Cash Flow (NCF) Rent estimates	Government oil and gas revenues
	\$ millions							
	1962-88	1962-89						
\$ millions	\$ millions	\$ millions	\$ millions	\$ millions	\$ millions	\$ millions	\$ millions	\$ millions
1972	7,437	1,647	2,836	1,647	2,836	3,441	3,331	1,345
1973	9,350	2,920	4,600	2,920	4,600	5,519	5,173	2,179
1974	11,691	4,779	7,088	4,779	7,088	8,750	7,495	5,254
1975	12,828	5,514	7,998	5,514	7,998	9,779	7,430	4,585
1976	13,585	5,778	8,725	5,778	8,725	10,416	7,014	4,580
1977	15,788	7,234	10,301	7,234	10,301	12,227	8,169	4,433
1978	16,697	6,652	10,118	6,652	10,118	11,881	7,798	5,416
1979	19,448	7,149	11,502	7,149	11,502	14,074	9,211	5,528
1980	21,047	8,793	10,997	8,793	10,997	14,524	9,106	6,474
1981	20,507	4,818	9,691	4,818	9,691	12,772	10,044	5,923
1982	22,124	7,394	11,513	7,394	11,513	15,023	13,104	3,779
1983	23,979	10,492	12,507	10,492	12,507	16,281	15,763	4,620
1984	26,246	11,832	14,340	11,832	14,340	18,277	16,450	4,976
1985	26,728	10,310	13,610	10,310	13,610	17,562	14,622	4,470
1986	18,036	3,618	4,810	3,618	4,810	6,568	8,762	1,836
1987	19,523	4,451	4,742	4,451	4,742	6,561	8,404	2,891
1988	17,135	1,553	1,595	1,553	1,595	2,180	3,617	2,384
1989	17,824	-	1,794	3,008	1,794	2,442	5,777	2,454
1990	19,421	-	-	4,393	5,557	7,921	7,466	2,724
1991	16,802	-	-	1,798	2,274	3,247	3,819	2,036
1992	17,313	-	-	3,645	4,610	6,471	6,291	2,187
1993	19,201	-	-	3,050	3,858	5,359	6,306	2,853
1994	21,297	-	-	1,251	1,582	2,154	4,998	3,398
1995	21,440	-	-	1,396	1,766	2,635	5,139	2,761
1996	25,464	-	-	3,737	4,728	7,130	8,644	3,884
1997	25,853	-	-	1,434	1,814	2,695	5,509	3,575
average (1992-97)	21,728	-	-	2,419	3,060	4,407	6,148	3,110

Source: Born, Alice (1992). *Development of Natural Resource Accounts: Physical and Monetary Accounts for Crude Oil and Natural Gas Reserves in Alberta*. Statistics Canada.

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