FINAL REPORT

—Northern Oil and Gas Directorate—

Indian and Northern Affairs Canada

Comparative Analysis of Fiscal Regimes

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Prepared for

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Executive Summary

The Oil and Gas Directorate administers the petroleum regime in the Northwest Territories (NWT), Nunavut and the northern offshore. This is the northern portion of Canada's "Frontier Lands" as defined in the Canada Petroleum Resources Act. The royalty regime prescribed by the Frontier Lands Petroleum Royalty Regulations (Frontier Lands regime) is designed to address the long lead times and high cost of petroleum development in the North.

After several years of experience in administering the regime for producing fields in the southern NWT, and recognizing that fiscal regimes in other jurisdictions have evolved, the Directorate was interested in reviewing the relative efficacy of the Frontier Lands regime.

As well, there has been a recent publication of the Pembina Institute providing comparison of economic rent captured by the fiscal regimes of Frontier Lands, Alberta, British Columbia, Saskatchewan, Alaska and Norway. The Pembina Report concluded that the fiscal regimes of the Canadian jurisdictions capture less of the available economic rent than those of Alaska and Norway. The Directorate was also interested in obtaining an assessment of the Pembina Report's conclusions.

The objectives of this report are:

1. Comparative analysis of the efficacy of the fiscal regimes of Frontier Lands, Alberta, British Columbia, Alaska and Norway; and

2. Assessment of the Pembina Report's conclusions.

Analysis of Fiscal Regimes

The Frontier Lands fiscal regime uses a combination of a *Resource Rent royalty* (royalty as a share of net cash flow after payout) and a minimum *Ad Valorem royalty* (royalty as a share of wellhead revenue). Alberta, British Columbia and Alberta use cash bids combined with an Ad Valorem royalty type; however, Alberta and British Columbia have some added features such as price sensitivity. Norway uses an Accounting Profits royalty enacted as a special income tax from oil and gas companies.

An in-depth assessment of the fiscal regimes was done using two well-established methods—qualitative and play economics. For the former, we provided a framework.

The following is a summary of the assessment of the fiscal regimes using the criteria in the qualitative framework that shows the most significant differences.

Assessment of Fiscal Regimes

Criteria \ Regions	Frontier Lands	Alberta	British Columbia	Alaska	Norway
Neutrality	●	◐	◐	○	●
Cost Recovery	●	○	○	○	◐
Robustness	●	◐	◐	○	●
Optimizing Rent Extraction	●	◐	◐	○	●
Mitigation at the Margin	●	◐	◐	○	●
Minimum Royalty	●	●	●	●	○
Administrative and Compliance Efficiency	○	◐	◐	●	◐
Certainty	○	◐	◐	●	○

LEGEND ● = High Rating ○ = Low Rating

The assessment of fiscal regimes was also done using play economics, which showed the extent of available economic rent captured by fiscal regimes.

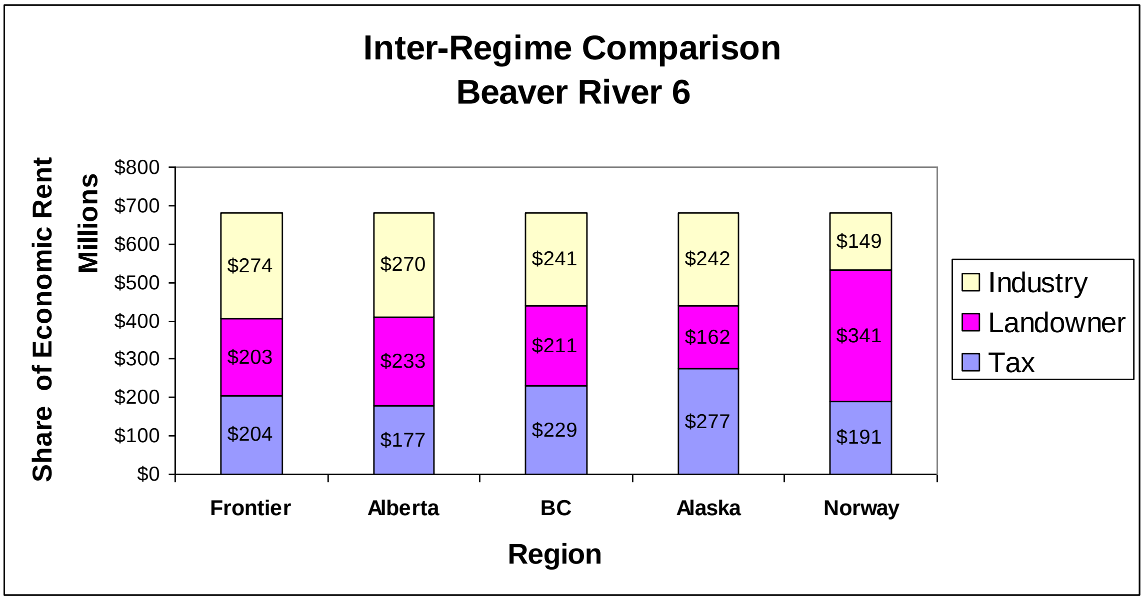
Economic rent is what can be extracted by a resource owner without impairing industry's ability to earn the minimum return required to attract investment. In a fully competitive market, the expected amount of economic rent would be the maximum amount that a potential developer is willing to pay the land owner for the right to develop the resource.

The amount of available economic rent is related to site-specific factors and general economic factors. The former affects the costs of exploration, development and production and the latter includes resource price and cost of attracting investment capital. The available economic rent is calculated for a prospect.

The analysis in the report is based on four established gas plays of the NWT—Beaver River, Windflower, Colville and Upper Keg River. The available economic rent in these prospects was determined using two price scenarios, \$4.5/mcf and \$6.00/mcf (Canadian \$ real 2005). Available economic rent for these eight cases was established using a cash flow model—Regime Economic Analysis Model. Then fiscal regimes of the jurisdictions under review were applied to establish the rent captured by industry and governments, and also the tax collected by the governments.

The following are examples of the results of the analysis. It shows the share of economic rent captured in dollars and percentages under various regimes for the most profitable case considered (the Beaver River 6 case).

Economic Rent Captured ($)



Percentage of Rent Captured

Region / Prospects	Inter-Regime Comparison				
	Frontier Lands	**Alberta**	**B.C.**	**Alaska**	**Norway**
Industry	40%	40%	35%	35%	22%
Land Owner	30%	34%	31%	24%	50%
Tax	30%	26%	34%	41%	28%

The following table summarizes the total take by government, royalty plus tax, as a percentage of the available economic rent for the six cases with positive economic rent.

Total Take By Government

Prospects	Government Share of Pre-tax Rent					
	BR 6	**BF 4.5**	**Colville 6**	**Colville 4.5**	**Windflower 6**	**Windflower 4.5**
Frontier Lands	60%	59%	59%	58%	52%	45%
Alberta	60%	61%	64%	68%	62%	65%
B.C.	65%	65%	67%	70%	64%	65%
Alaska	65%	65%	62%	65%	65%	68%
Norway	78%	78%	79%	81%	78%	79%

It is generally accepted that fiscal regimes should capture between 60% and 80% of the available economic rent. This range provides a compromise between two objectives; maximizing the collection of economic rent and encouraging development. The analysis shows that the Frontier Lands regime captures around the lower end, while Norway's regime captures around the high end of the range. We found that the Frontier Lands regime was most favourable to industry of the regimes considered. This greater share of economic rent taken by industry may be necessary to attract industry to the North, which is relatively unexplored, lacks infrastructure and has harsh physical conditions.

Pembina Report

The Pembina Report (Report) based its conclusions regarding the effectiveness of fiscal regimes of the jurisdictions considered on the extent of economic rent captured by them.

After an in-depth review of the Report, we conclude:

- Although the Pembina Report presents its results in terms of economic rent, it measures cash flow, and not economic rent. Its methodology is flawed;
- In some cases where government's take is above 100%, the report states the share as 100%. This obscured its use of flawed methodology; and
- The jurisdictions chosen for the comparison were inappropriate because of a number of factors including proximity, the nature of geology and the stage of development.

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1.0 Introduction

The passage of the Frontier Lands Petroleum Royalty Regulations in the late 1980s, established a generic royalty regime consisting of a combination of Ad Valorem and Resource Rent Royalty. Since that time, a number of prospects have been developed. Due to the lack of transmission facilities, the development has generally been restricted to the southwest part of the Northwest Territories (NWT). However, significant changes in the business environment are taking place which would increase the pace of resource development. These include the construction of one or two transmission pipeline systems providing northern resources access to the southern markets, declining U.S. domestic production of oil and gas and necessary appetite for energy, settlement of First Nation land claims and the desire of First Nations to participate in resource development.

Appendix 1 provides further background regarding the resources of the Frontier Lands and the jurisdictions used for comparison.

As well, there has been a recent publication of the Pembina Institute providing a comparison of the economic rent extracted by fiscal regimes of Frontier Lands, Alberta, British Columbia, Saskatchewan, Alaska and Norway. The Pembina report's conclusions include that economic rent extracted by the fiscal regimes of Canadian jurisdictions including the regime of Frontier Lands, captures much smaller economic rent than the regimes of Alaska and Norway.

The objectives of this report include:

1. Comparative analysis of the efficacy of fiscal regimes of Frontier Lands, Alberta, British Columbia, Alaska and Norway; and

2. Assessment of the Pembina Report's conclusions.

This report provides an in-depth comparative analysis, qualitative and quantitative analysis of fiscal regimes of the jurisdictions considered and an assessment of the assumptions, methodology and conclusions of the Pembina report.

The report is divided into eight sections:

- Section 1.0 provides an introduction to the report;

- Section 2.0 provides an overview of the core concepts including economic rent, various royalty types and a framework for assessing the various royalty types;

- Section 3.0 summarizes the fiscal regimes of the jurisdictions under review;

- Section 4.0 provides an assessment of the fiscal regimes of jurisdictions under review using the framework developed in Section 3.0;
- Section 5.0 provides an overview of the methodology used in the comparative economic analysis;
- Section 6.0 provides the comparative assessment of fiscal regimes of jurisdictions when applied to the four prospects of the NWT;
- Section 7.0 provides the assessment of the Pembina Report; and
- Section 8.0 provides the conclusions.

2.0 Concepts

2.1 Royalty and Tax

In most countries, ownership of hydrocarbon resources as they exist in situ, is publicly[1] owned. However, the exploration, development and production, are in most cases not undertaken by a government, but by a private sector company. In return of the right to explore, drill, produce and sell these non-renewable resources, the government demands compensation or a purchase price. This compensation is called “royalty.”

The distinction between a royalty and tax is important. A tax is a general revenue raising measure levied on economic activities to fund government spending. However, a royalty represents the compensation for the depletion of an asset. The critical issue for a royalty is thus not the amount of government revenues required in any period, but the appropriate price to charge for the depletion of this capital asset. It follows that royalty should be calculated independently of the revenue needs of the government.

2.2 Economic Rent

The approach most commonly used to provide community returns from a resource with an unknown initial value, but with some probability of a future high value, has been to require payment in the form of royalties after resource delineation and production has taken place. If this approach is to have any of the benefits of a market price mechanism, it follows that the royalty paid should bear some relation to the real value of the resource.

The real value of a resource to the resource owner is defined as its economic rent. While this rent can only be known with certainty at the end of a project life, it can be estimated during the development phase. In principle, the calculation of economic rent provides a way to establish a compensation price which relates directly to the realized economic value of the resource.

Economic rent is what can be extracted by a resource owner without impairing industry's ability to earn the minimum return required to attract investment. A positive amount of economic rent exists for any resource where revenue from sales exceeds the cost of development by a margin that compensates the developer for the risks incurred. In a fully competitive market, the expected amount of economic rent would be the maximum

[1] In Canada, “publicly owned” may refer to the Federal government, an Indian government, a provincial government, or a municipal government.

amount that a potential developer would be willing to pay the landowner for the right to develop the resource.

Whatever methods the owner of the mineral resource uses to collect payments from the developer, the total payment collected is limited by the economic rent available. An owner that attempts to collect too much will adversely affect the continuing development of the resources and offers inadequate incentives for future investment.

The amount of economic rent available from a particular resource is related both to site specific characteristics and to general economic factors. Site specific factors include such things as how much resource is there, how deep it is, how much can be recovered, how fast it can be recovered, and how far it is from infrastructure and markets. General economic factors include resource prices, the cost of attracting investment capital from other investment opportunities, and uncertainties relating to government policy.

The normal methods available to the resource owner for collecting economic rent include initial payments for a lease (bonus bids), annual lease rentals, and royalty on production. Also, a government, as a resource owner who does not engage in the recovery of oil and gas, needs to transfer the mineral rights to a private enterprise at a price which will reflect the fair market value. It is extremely difficult to ascertain the correct present value of resources. Where information on the resource is substantial, a cash bonus bidding system has proven to be an effective method of resource conveyance. In frontier areas, where information about the quantity and value of hydrocarbon resources is minimal, cash bids are at best a guess as to the value of the resources. Hence, the government may choose another approach.

There are a number of bidding alternatives including a cash bonus bidding with a fixed royalty requirement and cash bidding without a royalty requirement (Pure Bid). The former system is popular as a conveyance and rent collection system in many jurisdictions such as Alberta, British Columbia, and Alaska. The cash bonus bidding with a fixed royalty system allows the bidding system to overcome some of the difficulties, in accurately calibrating royalty formulas to the economic rent that varies by site. A resource developer will adjust the bid consistent with their estimate of the available economic rent given the royalty and tax obligations.

The cash bonus bid with a fixed royalty system has many advantages. However, it poses a number of problems including removal of significant front-end money paid to the government from exploration and development and failure to capture windfall profits. The first problems can be addressed using work commitment bidding instead of cash bids. Work commitment bidding can be used as a vehicle to rectify the weaknesses of the cash bidding system. With the work commitment bidding, the resource developer directs cash into additional exploration and development. The additional expenditures will increase future production to such an extent that the government will be able to recoup the foregone cash bonus in the form of increased royalty, taxes and ancillary benefits of increased employment. The problem of windfall profits requires some type of royalty that is sensitive to changes in price or other factors that affect profit.

Where a government is the resource owner, there are additional considerations related to how to collect rent and how much to collect. Public policy normally considers long term economic development impacts and issues such as employment, environmental impacts, and public perception of fairness.

A government, as resource owners, must address the following issues:

1. How much economic rent is available?

2. What portion of available economic rent should the resource owner take?

3. What should be the method of extracting the economic rent?

2.3 Measurement of Available Rent

Ideally, for the fiscal devices to collect the rent efficiently, the resource owner should accurately measure the available economic rent.

In practice, the measurement of rents is not straightforward. It requires knowledge of the costs of finding, developing and operations; transportation and processing costs; production profiles; prices; and investor's discount rates. Moreover, the uncertainty associated with estimates of revenues and costs is itself a cost factor, and an economic cost must be assigned to this uncertainty. This is a demanding list of requirements, but if inaccurate measures are employed, economic distortions can then arise.

Knowledge of finding costs is, at best, elusive, requiring knowledge of prospectivity, as well as the actual necessary costs.

2.4 How Much Rent Should Be Taken

As a resource owner, in deciding how much rent it should take, the government should focus on optimizing the long term public interest. If too little rent is collected, part of the economic rent will be forfeited as excess profit to the industry. If too much rent is extracted, there will be an inadequate incentive for future investment.

Public policy should provide incentive for industry to find and develop resources efficiently and recognize the need to provide for the margin of error in establishing the available rent.

Recognizing the uncertainties inherent in estimating economic rent, the resource owners should adopt the more modest aim of obtaining a preponderance of, rather than all, the apparent and uncertain long-run economic rent. It is difficult to specify a precise amount; however, a target of two-thirds to a three-quarter of the available rent would leave scope for incentives and allow for a margin of error. It may also allow for higher eventual long term revenues for the resource owners by attracting new investments.

2.5 Method of Rent Collection

The method of acquiring the rents may be divided into three categories:

a) A up-front payment (e.g. bonus bid);
b) A stream of payments based on production (e.g. royalty); and
c) A combination of the above two.

Up-front payment method captures quality-type rents provided (1) there is good knowledge regarding the quality of resources (including the amount, value, and cost of development) and (2) there is good competition for the acquisition of the mineral rights. However, up-front payment method is not effective if the foregoing is lacking, and for collecting rents due to unexpected variations in prices. Furthermore, it does not satisfy a government's need for stable future revenues. Also, a large, up-front payment increases the investor's risk. Therefore, a need to have flow type mechanisms, royalties, is paramount.

The lack of good knowledge of the quality of resources also makes it difficult to design a royalty system to extract the desired rent. There are a number of rent extraction options with different attributes available to a resource owner. A resource owner should choose the option that helps it to achieve long term public interest.

Following are the options generally used:

i) *The Specific Royalty (SR):* This is an amount per unit of production; for example, $0.60 per barrel of crude oil. (Used in Alaska as a minimum severance tax.)

ii) *The Ad Valorem Royalty (AVR):* This is an amount based on a percentage of value of resources; for example, 5% of gross revenues from the sale of natural gas. (Used in Alaska with flat rates. Used in Alberta and British Columbia with sliding scales. Used on Frontier Lands as a minimum, with step scales.)

iii) *The Accounting Profits Royalty (APR):* This is an amount based on a percentage of the accounting profits of a company. This can be designed to be site specific. It permits depreciation and annual costs to be deducted from gross revenues. The resource owners receive rent once the company is profitable. The costs are those generally allowed for income tax purposes. (Used in Norway.)

iv) *The Resource Rent Royalty (RRR):* This is an amount based on net cash flow after allowing the investor to achieve a specified rate of return on a project before royalty becomes payable. The resource rent royalty is payable only after the project payout occurs; when cumulative gross revenue first equals the sum of total allowed capital costs, operating costs, overhead allowances, and the cumulative return allowance. (Used on Frontier Lands, in combination with a minimum ad valorem royalty.)

The costs are project specific and may include exploration, discovery and delineation wells, development drilling and production. The specified rate of return should represent the investor's discount rate.

v) *Pure Bid (one up-front cash bid):* This is an amount paid at the time of resource allocation in an auction among competitive bidders. The amount is based a net present value estimate of the expected economic rent in a project and on expectations regarding competitive bids. (Used in Alberta, British Columbia, and Alaska, in combination with an ad valorem royalty.)

There are other options such as net carried interest and Production Sharing Agreements (PSA). The feasibility of these instruments cannot be divorced from the terms and conditions under which resources are held—the land-tenure system. For example, if the period for which a resource license is held is seen as too short to allow a reasonable chance to recover costs, then schemes relying heavily on percentage of gross revenues would be unattractive to developers.

The government also extracts revenues from developers in the form of income and property taxes. For a company as a developer, the overall government takes is what matters most, irrespective of its derivation, from government's role as owner, or as general tax authority.[2]

[2] *For a private owner of freehold mineral rights, tax is considered a cost, so that economic rent is calculated after the taxes that are paid by the developer. For a government owner that may also be the tax authority, there can be confusion as to what payments are collected as compensation rent from the development of the resource and what payments are collected as taxes for the general purpose of government. In our analysis, we explicitly distinguish between the portions of the fiscal regime that are payments of tax and those portions that are payments to the owner of the resource.*

2.6 Framework for Evaluation of Royalty Options

The effectiveness of royalty options should be assessed against a government's policy objectives. Following are a number of criteria which may be used to evaluate various royalty options; these are neither exhaustive nor independent:

1. Acceptability

The royalty payers should perceive the royalties to be fair and consistently applied. The government's policy should be aimed at full-cycle economics rather than short-run rents. Therefore, prior to implementation, buy-in from industry should be obtained.

2. Neutrality

Royalties should avoid distorting the workings of the market mechanism. Royalties must not deter exploitation of the full range of reservoirs and influence the pace, timing and ranking of development reservoirs.

A project offering positive returns before royalty should not be discouraged by royalty. To the extent royalties are focused on the economic rent, they will tend to be non-distortionary.

3. Mitigation at the Margin

Royalties should leave the return on the marginal investment, and on marginal output, unimpaired. The royalties should not inhibit development of a poorer quality, higher cost, reservoirs. High cost, marginal resource deposits are those which are characterized by:

- A high number of wells drilled per successful, commercial discovery;
- Small, rather than large, discovered reserves;
- High drilling costs per well; and
- Poor or low grade oil and gas deposits in the reserves.

The royalties should not result in early abandonment.

4. Consistency

The principle of consistency rests on two points: first, equality of treatment of resources of equal quality; and second, treatment of different quality resources with an appropriate degree of inequality. For example, high royalties should be taken from the resource with higher quality. The proportion of rent paid by a high quality field should be at least as high as that paid by a low quality field; the proportion paid when prices are low should be no more than when prices are high.

5. Robustness

A royalty system would be able to respond to the changes in the economic environment, particularly prices and costs. It is a challenging task to design a royalty system which would be able to withstand changes in the economic environment over time.

6. Cost Recovery

A royalty system should allow recovery of full cycle costs; that is, exploration, development and production. It should allow both direct and indirect costs. Otherwise risky ventures would be avoided.

7. Sharing the Risk

An effective royalty system should provide an acceptable division of risk between the producers and government. Different royalty systems embody different risk characteristics. Pure bid systems shift risks to producers. Resource Rent Royalty with generous return allowances shift risks to government.

8. Optimizing Rent Extraction

The principle of optimizing rent extraction is preferred to the principle of maximizing rent extraction when the latter is defined as raising royalty rates to the point of undermining investor confidence. Also, maximization would leave little margin for error in the design of a royalty system.

In practical terms, the Crown needs to show some restraint in resource pricing in order to sustain investor confidence, and it means that the royalty should be sensitive to variations in the profitability of site-specific operations over the entire business cycle. It also means that the resource owner’s share of economic rent should be variable to reflect market conditions such as changes in commodity prices, inflation and costs.

9. Competition

A resource owner should be sensitive to the royalties in the competing jurisdictions, both domestically and internationally. This is because the risk capital needed for hydrocarbon development moves freely across national and provincial boundaries.

However, comparisons among regimes are not easy, requiring adjustments to account for differences in resource endowments and other elements of the overall tax and land tenure system.

10. Fiscal Interaction

A royalty regime should not be designed without regard to the land tenure system and other fiscal instruments. A producer is concerned with the total take of the government rather than its parts.

11. Imposition of Minimum Royalty

This principle provides that a government as a resource owner should receive a minimum royalty as a basic participation fee in industry. Such a floor levy can be seen as compensation to owners for any costs they incur. However, this fee should be small so as not to inhibit activity.

12. Consistency of Flow

A government's financial planning requires predictability of revenues. Therefore, fiscal regimes should facilitate predictability and steady flow.

13. Administrative and Compliance Efficiency

The proportion of royalties dissipated by collection and compliance costs should be modest. These costs are not only borne by the government but also by royalty payers. A simple and well understood royalty would tend to be administratively efficient.

Principal costs are:

- The information costs associated with determination of the royalty to be paid;
- The cost of actually collecting the royalty, including any negotiation costs and court costs resulting from disputes over the amount owed;
- The cost of assurance that the right amount of royalty has been paid and the process and control system are efficient and effective;

- The costs of policy and legislation reviews required when government deems it necessary to review the current royalty system; and

- The costs associated with enacting and implementing any changes to the royalty system.

14. Certainty

There should be certainty as to who are the royalty payers, what are their obligations and the timing for discharging these obligations. The higher the uncertainties, the greater will be the inefficiencies in the system and possibly loss of rents to the government. For example, in resource rent royalty, the eligible costs should be defined comprehensively in order to avoid inefficiencies and higher costs of providing assurance. Complex rules or vague interpretations reduce certainty even if the direct administrative cost of the complex rule is small.

3.0 Review of Fiscal Regimes

Exhibit 1, *following*, provides a summary of features of the fiscal regimes of the jurisdiction under consideration. In this section, we briefly describe the features of the fiscal regimes. The appendices provide additional details of the regimes.

3.1 Frontier Lands[3]

3.1.1 Land Tenure

Land tenure is legislated by the Canadian Petroleum Resources Act, and administered by the Department of Indian and Northern Affairs. Exploration licenses are awarded based on work expenditure bids. Generally, the government selects an area for development in consultation with the local community and issues a call for bids. The government is not obligated to accept any bid. In case of competition for exploration rights, the company with the highest planned expenditure is normally awarded the rights. There is no cash bonus bid currently applied. A refundable deposit equal to one-fourth of the work plan is required. The maximum term of an exploration license is nine years. If a discovery is made, then the Department issues a Significant Discovery License, with indefinite term. Production requires a Production License following determination of commerciality.

An escalating annual rental, refundable with additional work, applies during the second half of an exploration license. No rental applies to a significant discovery license.

[3] *We use "Frontier Lands" to refer to the Crown Lands in northern Canada where petroleum development is governed by the Canadian Petroleum Resource Act and administered by the Department of Indian and Northern Affairs.*

Exhibit 1 **Royalty Features**	Frontier Land Canada	Alberta	British Columbia	Alaska	Norway
♦ Productivity Sensitive	No	Yes	Oil—Yes Gas—No	No	No
♦ Price Sensitive	No	Yes	Oil—Yes Gas—No	No	No
♦ Address Costs Directly	Yes	No	No	No	Yes
♦ Avoid Early Abandonment	No	Yes	Oil—Yes Gas—No	Yes	No
♦ Vintage	No	Yes	Oil—Yes Gas—No	Royalty—No Tax—Yes	No
♦ Quality Sensitive (Oil)	No	Yes	No	Yes	No
♦ Address Exploration Costs	Limited	Partial	No	Partial	No
♦ Valuation—Price: - Actual - Index	Actual	Oil—Actual Gas—Index	Actual	Actual	Actual
♦ Leasing Rights	Bid	Bid	Bid	Bid	Bid/Negotiate
♦ Site Specific	Yes	Yes	Yes	Yes	?
♦ Processing Costs: - Actual - Postage Stamp	Actual	Partial Postage Stamp	Postage Stamp	No?	Yes
♦ Byproduct Royalty	Yes	Yes	Yes	No	?
♦ Type of Royalty	Ad Valorem & RRR	Ad Valorem	Ad Valorem	Ad Valorem	No Royalty/Tax (Accounting Profit)
♦ Minimum Royalty	1-5% of Gross	Oil—0% Gas—5%	Oil—0% Gas—15%	12.5%	Tax: 28% + 50%
♦ Maximum Royalty	30% Net Profit	Oil—40% Gas—35%	Oil—40% Gas—30%	12.5%	Tax: 28% + 50%

3.1.2 Royalty Rate

Royalty rates are specified in the Frontier Lands Petroleum Royalty Regulations; P.C. 1991-2470; 12 December, 1991 (SOR 92-26); under the Canadian Petroleum Resources Act (R.S.1985—c36, 2nd sup). Consolidation at:

http://laws.justice.gc.ca/en/C-8.5/SOR-92-26/42366.html#rid-42418

This regulation applies to all Frontier Lands. The regulation overrides any other royalty provision except for those leases covered by the Norman Wells Agreement of 1944 and the 15 specific leases identified in Section 114-4 of the Canadian Petroleum Resources Act.

Before payout, the royalty is a flat ad valorem rate with time dependent stepped increments. Rate is 1% for first 18 months of production, increasing in increments of 1% every 18 months to a maximum of 5% (Reference: Section 3.1.a).

After payout, the royalty is the greater of net a resource rent royalty of 30% or an ad valorem royalty of 5%. (Reference: Section 3.1.b). The return allowance used in calculation of the payout is the long term Bank of Canada bond rate plus 10%.

3.1.3 Federal Income Tax

Corporate tax rate on income is 21%. (Reference, Income tax Act; 21% is the combined effect of the result of the 38% rate specified in Section 123(1)(a) reduced by the 10% specified in 124(1) and the 7% in Section 121.1.)

A federal capital tax applies to large corporations with annual income over $50 million. The rate for 2004 is 0.2%. The tax is being phased out and will be eliminated by 2008. (Reference, Section 181.1.)

A federal surtax of 1.12% applies to all corporations. (Reference Section 123.2.) The percentage rate is 4% of the 28% general rate that applied in 2000. The surtax was eliminated for individuals, but remains unchanged for corporations.

Corporations in the resource sector use the general rates for the federal capital tax and surtax, but currently see a different federal basic tax rate. However, the rates are being harmonized, so that the resource sector rate will be 21% in 2007. The federal government had been providing a 25% resource allowance in lieu of deductibility of royalty payments to provincial governments. The resource allowance is also being phased out and provincial royalties will be fully deductible by 2008. (In our analysis, we use the (harmonized) rates as they will be in 2008.)

In computing federal tax, all costs related to exploration are expensed immediately (Reference section 66.1; Canadian Exploration Expense). Costs related to development are depreciated at the rate of 30% per year (declining balance method). (Reference section 66(142); Canadian Development Expense.)

Companies on federal lands administered by INAC will also pay tax to either the Northwest Territories or to Nunavut.

The Northwest Territories tax rate on large corporations is 12%.

The Nunavut tax rate on large corporations is 10.5%. Nunavut has a mining tax, but it does not apply to oil and gas.

3.1.4 Added Tax

A federal sales tax of 7% applies. The tax is a valued added tax. The effect of the value added tax is the similar to an income tax except based on cash flow.

Neither the Northwest Territories nor Nunavut has a sales tax.

3.2 Alberta

3.2.1 Land Tenure

Exploration licenses are awarded on the basis of cash bonus bids, payable at the time of the award. Bidding rounds are held every two weeks on prospects identified by industry. The government posts all nominated tracts and accepts the highest bid. The minimum bid is equal to one year's rental. There is no work requirement. However, the license period of 3 years cannot be extended unless a well has been drilled. A successful well allows the license holder to convert to a production lease on the proven resource. A dry hole allows the license holder to extend the license for an area the size of which depends on the depth of the well drilled. Oil and gas may be produced and sold from either a license or a lease. An annual rent of $2.50 per hectare per year applies to a license or a lease. The annual rent is deductible from royalty.

3.2.2 Royalty Rate

For oil and gas, an ad valorem royalty is payable on wellhead value. The rates are set by sliding scale formulas that are sensitive to rate of production and to market price. Different formulas and rates apply to oil, gas, gas by-products, and heavy oil. There are also different formulas based in date of discovery (vintages of oil, new, and third tier).

Details of the Alberta sliding scale formulas are presented in Appendix 2.2.

3.2.3 Royalty Holiday and Reductions

Alberta provides a one-year royalty holiday on oil from an exploratory oil well. A five-year holiday applies to oil from a re-activated oil well.

3.2.4 Income Tax

Alberta Corporate tax rate is 11.5%.

3.2.5 Value Added Tax

The federal value added sales tax of 7% applies. Alberta does not have a sales tax.

3.3 British Columbia

3.3.1 Land Tenure

Exploration licenses are awarded on the basis of cash bonus bids, payable at the time of the award. An annual rent of $2.50 per hectare per year applies to a license or a lease. The annual rent is deductible from royalty.

3.3.2 Royalty Rate

For oil and gas, an ad valorem royalty is payable on wellhead value. The rates are set by sliding scale formulas that are sensitive to rate of production and to market price. Different formulas and rates apply to oil, gas, gas by-products, and coal bed methane. There are also different formulas based on date of discovery (three vintages).

Details of the British Columbia sliding scale royalty formulas are included in Appendix 2.3

3.3.3 Income Tax

The corporate tax rate is 13.5%.

3.3.4 Value Added Tax

The federal value added sales tax of 7% applies. British Columbia also adds a 7.5% provincial sales tax.

3.4 Alaska

The following describes the regime on lands where the State of Alaska owns the mineral rights. The regime on federal lands within Alaska and offshore is essentially the same, except that the federal government gets the bonus and royalty payments. The State of Alaska income and severance taxes apply to all lands, without regard to whether mineral rights belong to the state, to the federal government, or to private parties. Currency values are expressed in U.S. dollars. One U.S. dollar is currently worth $1.23 Canadian dollars.

3.4.1 Land Tenure

Exploration licenses are generally awarded on the basis of cash bonus bids, payable at the time of the award. Exploration license term is ten years. Alaska has experimented with variations on the cash bonus bid, but generally uses the traditional bid arrangements. The government undertakes an economic evaluation of each prospect and posts a minimum bid for each parcel. The bidder must also submit a work plan. The government is not required to accept any bid and can award the license to a low bid on the basis of a higher work plan. If 25% of the work plan is not completed by the fourth year of the license, the government can require a portion of the license area to be relinquished.

An annual license rent starts at $0.50 per acre and increases by $0.50 per year to a maximum of $3 per acre per year. An annual lease rental of $0.50 per acre per year applies to shale oil leases. A lease rental rate of $1 per acre per year applies to shallow gas leases. The lease rental rate for other oil and gas leases is $3 per acre per year. The annual rent is deductible from royalty.

3.4.2 Royalty Rate

The royalty rate is a flat ad valorem rate of 12.5%. Alaska has experimented with variations, including sliding scale royalty and net profits royalty, but generally uses the traditional flat royalty.

3.4.3 Income Tax

The U.S. Federal Tax rate of 35% applies. State and municipal taxes are deductible from income when computing federal tax, so the effective federal tax rate depends on the amount of state and municipal taxes paid. For a corporation that pays the Alaska corporate tax rate of 9.4%, the effective federal tax is 31.76%. Because the Alaska severance tax is also deductible from income when computing federal tax, the effective U.S. corporate tax on oil and gas corporations is reduced further.

Corporations with income over $90,000 pay a corporate tax rate of 9.4% on Alaska source income above this amount. For oil and gas corporations, total world income is used when setting the rate.

3.4.4 Value Added Tax

There is no U.S. or Alaska sales tax.

3.4.5 Other Charges

A severance tax applies. The severance tax is computed similar to a sliding scale royalty. However, it is computed on gross sales value of oil or gas in marketable condition, with no deduction for costs. The severance tax is the Government of Alaska's principle source of tax revenue (Alaska has no state individual income tax or sales tax). The severance tax is described in Alaska Statues, Chapter 43.55. Text of this chapter is at:

http://www.tax.state.ak.us/programs/oil/programs/ogproduction/statutes/Chap43.55_OGProd.htm

The base severance tax is 10% for gas. The base severance tax for oil is 12.25% for the first five years of production and 15% thereafter. The minimum tax for gas is $.064/mcf. The minimum tax for oil is $.80/barrel. There is an API gravity adjustment for the minimum oil tax.

The base severance tax is adjusted to an effective tax based on production. The adjustment applies to each well. The adjustment is a multiplicative factor that is always less than one. Hence the adjustment reduces the base severance tax for wells with lower rates of production.

For gas, the adjustment factor is [1-(3000/P)] where P = gas rate of production in mcf/day. If P is less than 3000 mcf per day, then the factor is zero, so there is no tax. At higher rates of production, the factor approaches 1, so the tax approaches the base rate of 10%.

For oil, the adjustment uses both well rates and the total field rate. The base rate is multiplied by [1-(300)/P]^[(150,000/FP)^1.5333], where P=well rate of production in barrels per day, FP = field rate of production in barrels per day, and the symbol ^ refers to exponentiation. If P is less than 300 barrels per day, then the adjustment factor is zero, so there is no tax. At higher rates of production, the factor approaches 1, so the tax approaches the base rate of 12.25% or 15%. The exponents cause the adjustment factor to move to 1 quickly for large fields and slowly for small fields.

The rates for the severance tax for oil are in AS 43.55.011. The rates for gas are in AS 43.55.016. The adjustments, called the economic limit factor, are described in AS 43.55.013

Graphs of the severance tax curves are presented in Appendix 2.4.

3.5 Norway

The Government of Norway directly invests in petroleum prospects as operator and working interest. However, the government takes industry partners as working interests and as contractors. The following description applies to any company that acquires a working interest in Norway. Currency values are expressed in Norwegian krones. One Norwegian krone is currently worth $0.197 Canadian dollars.

3.5.1 Land Tenure

The government invites proposals regarding tracts that it wishes to develop. After reviewing the proposals, Statoil invites selected parties to participate in a join venture. Companies may be offered participation as contractors and receive a working interest in production as payment for their work. Companies may also be invited to contribute cash in return for a working interest. In all cases, the operator of the joint exploration venture is determined by Statoil.

3.5.2 Royalty Rate

Norway imposes a special income tax on oil and gas companies. This “tax” is intended to replace royalty. The special tax finances the government participation in the development of petroleum. Once the government cumulative cash position became positive (in 1996) surplus monies have been transferred to the Norwegian

Government Petroleum Fund, managed by Norges Bank under general guidance from the Sorting (Norwegian Parliament).

The special tax is 50% of a company's net income from petroleum. In calculating net income, exploration costs are expensed as incurred. Development capital is depreciated over 6 years. Development capital cost receives a 5% profit allowance on the remaining balance for each of the six years the asset is being depreciated. Actual interest costs are included as costs unless interest is paid to a party not at arms length. Interest expense is also limited by a requirement that the debt cannot exceed 80% of the book value of a company's assets.

3.5.3 Income Tax

Norway corporate tax rate is 28%.

3.5.4 Value Added Tax

Norway has a value added tax of 24%. However, the tax does not apply to the oil and gas industry.

3.5.5 Other Charges

A carbon dioxide tax applies to fuel used in oil and gas production and to gas flared. The rate is NOK .76 per Sm3 of gas or liter of oil.

4.0 Assessment of Fiscal Regimes

The following is the assessment of fiscal regimes using the criteria described in Section 2.0 of this report. In cases where the regimes are different for gas and oil, we apply the criteria to the gas regime because the gas prospects in Frontier Lands are used for comparative economic analysis in Section 6.0 of the report.

4.1 Frontier Lands

The strengths of the Frontier Lands regime are that it is consistent, robust, competitive, and provides full cost recovery. It is consistent in that it takes a higher share from the most profitable developments and a lower share from less profitable developments. It is robust—it adjusts automatically to changes in the price or quality of the resources, taking the expected share of in every case. It is also competitive with other jurisdictions and with other investment options—the share of economic rent taken by the government is low enough so that it will attract investors. The explicit recognition of costs provides excellent cost recovery.

The weaknesses of the Frontier Lands regime are that it has high administrative and compliance costs and the share of rent collected is less than optimal. The administrative and compliance costs are high because the regime requires collection of significant cost information, and the cost information required is different from the information that industry uses for internal accounting and also different from the information required for tax. The share of rent collected is slightly less than the optimal range because the amount collected from profitable developments is below the 60%-80% range that is generally considered optimal for such developments.

The regime has good mitigation at the margin for new developments. It collects little royalty from marginal developments, and will not prevent an uneconomic development from proceeding. However, the regime has poor mitigation for developments that become marginal after payout. The 5% minimum royalty will result in early abandonment of developments that would be economic with a lower royalty.

The regime shifts much of the risk from industry onto the government. This feature may be appropriate given the immaturity of the area. The immediate recognition of capital costs and liberal return allowances means that a development that does not achieve quick payout may never achieve payout.

4.2 Alberta

The strengths of the Alberta regime are that it provides certainty, is competitive, and generally captures rent in the optimum range. The certainty derives from the Alberta practice of invoicing for gas royalty, so that industry is never in doubt regarding the amount owing. The regime is especially competitive for low producing wells; Alberta's combination of royalty and tax rates is lower than rates in British Columbia and most of the United States. The various rates in the formulas are generally set so that the regime collects 60% to 80% of the economic rent for most of the actual developments in Alberta.

The weakness of the Alberta regime is that it is not consistent, is not robust, provides little recognition of costs, and has no mitigation at the margin. It is inconsistent in that it takes a lower share of economic rent from the most profitable developments than it does from those with lesser profit. It has limited robustness in that it has only limited response to price changes or changes in cost elements—current prices are well outside the range where Alberta's formulas show price sensitivity. Alberta provides for gas processing costs, but does not provide for prospects with high exploration or drilling costs. Alberta has in the past used short-term or special programs to improve its cost recognition. Failure to recognize costs leads directly to poor mitigation at the margin. Alberta's formulas will attempt to collect more than 100% of economic rent for any prospect that is marginal because of high cots. In particular, Alberta's regime will prevent marginal prospects from being developed in the high-cost northern areas, in mountainous areas, and in fields where the resource is tight gas or coal bed methane.

The competitive bidding climate of Alberta means that industry will correct some of the defects in Alberta's regime by making adjustments in the cash bids. The bidding system keeps the total amounts collected by Alberta within the optimum range. However, the upfront cash bids shifts risk to industry. Also, the cash bids are well matched to actual economic rent available only for prospects in mature areas where significant exploration history is available.

4.3 British Columbia

The British Columbia regime is very similar to the Alberta regime, and has the same strengths and weaknesses. The strengths are that it provides certainty, is competitive, and generally captures rent in the optimum range. Like Alberta, British Columbia issues invoices for royalty. The British Columbia invoice system pays particular attention to the accounting aspects of royalty collection—the administration of royalty collection is done by the same group which collects taxes. The amount of rent collected is competitive and generally in the optimum range. The total amount collected by the government is similar to Alberta. However, British Columbia collects relatively less as royalty and more as tax.

The weakness of the British Columbia regime is that it not consistent, is of medium robustness, provides little recognition of costs, and has almost no mitigation at the margin. It is inconsistent in that it takes a lower share of economic rent from the most profitable developments than it does from those with lesser profit. It is less robust in that it has only limited response to price changes or changes in cost elements—current prices are well outside the range where the formulas show price sensitivity. British Columbia provides for gas processing costs, but does not provide for prospects with high exploration or drilling costs. Failure to recognize costs leads directly to poor mitigation at the margin. British Columbia formulas will attempt to collect more than 100% of economic rent for any prospect that is marginal because of high costs. British Columbia has introduced special formulas for coalbed methane developments, providing both improved cost recognition and lower royalty. British Columbia has also recently introduced a royalty reduction for deep gas wells. Also British Columbia, in comparison with Alberta, takes less as royalty and more as tax. These adjustments improve mitigation at the margin. However, the British Columbia will still prevent marginal conventional prospects from being developed in the high cost northern area.

British Columbia has a bidding system similar to Alberta, but the bidding is not as competitive. British Columbia enjoyed a record year in 2003 after reducing royalty on deep gas wells. However, like Alberta, cash bids normally total about 10% of the amounts collected as royalty.

4.4 Alaska

The strengths of the Alaska regime are that it provides certainty and collects substantial minimum royalty on developments that proceed. Certainty is a consequence of the simplicity of the flat 12.5% royalty. This also provides a minimum royalty.

The weaknesses of the Alaskan regime are that it is not consistent, is not sensitive to costs, has no mitigation for marginal prospects, and does not optimize the amount of rent collected. It is inconsistent in that it takes a lower share of economic rent from the most profitable developments than it does from those with lesser profit. It is less consistent in this respect than the Alberta and British Columbia regimes because those two regimes have price sensitivity that removes some of the inconsistency. The Alaska regime is least sensitive to cost of any of the regimes considered—the severance tax does not recognize processing costs. There is some mitigation for marginal prospects because the severance tax is sensitive to rate of production. However the flat 12.5% royalty will prevent development of many marginal prospects. On the other hand, the flat 12.5% royalty takes only a small share of the economic rent available from the most profitable prospects. For the best prospects, the Alaska regime takes less than the optimum share of rent.

Alaska has a cash bidding system that differs from the Alberta and British Columbia bidding systems by normally imposing substantial minimum bids on each parcel. For normal prospects, the flat 12.5% royalty takes too little rent, so Alaska must collect a large amount of rent through the bidding system. Counting both the federal offshore area and the state lands, the total revenue collected from bonus bids has been more than $10 billion—more than has been collected by royalty. This high reliance on the up-front cash bid places a greater risk on industry.

4.5 Norway

The strengths of the Norway regime are that it is consistent, robust, optimizes rent extractions, and provides full cost recovery. These strengths are similar to the Frontier Lands regime, except Norway optimizes rent extraction while the Frontier Lands regime is more attractive to industry because the regime leaves industry a greater share. Norway is consistent in that it takes a higher share the most profitable developments and a lower share from less profitable developments. The Norway regime is robust—it adjusts automatically to changes in the price or quality of the resources, taking the expected share of in every case. The explicit recognition of costs provides excellent cost recovery. The Norway regime takes a total share of rent that is almost always in the in the 60%-80% range that is generally considered optimal—it is fact takes 78% of rent for most developments.

The weaknesses of the Norway regime are that it does not provide consistency of flow. In fact the Government of Norway had to invest significant taxpayer dollars in development of the resource. Although development is managed with high regard to a steady rate of development, the great ebb and flow of revenue required Norway to take special measures to stabilize its currency and to stabilize its government finance.

Norway avoids high administrative costs by having the rent collected from petroleum development using the same accounting information as for tax collection. Unlike U.S. and Canadian regimes that have different rules for tax and royalty, Norway has only one set of rules.

Because the government of Norway takes position of a working interest, the government takes the risk as the producer. It does not need to attract investors, because the government has decided to be the investor. Norway employs the international industry to provide special services where expertise is lacking in Norway. Thus industry takes the role of contractor in many cases. The partial “privatization” of Statoil—i.e., selling of some shares on the New York exchange—allowed Statoil to acquire interest in some non-Norwegian assets, but did not impact Statoil’s function as the senior partner in all Norwegian petroleum developments.

4.6 Summary

Exhibit 2, *following*, summarizes the evaluation of the regimes against the evaluation criteria.

Exhibit 2
Comparison of Fiscal Regimes

Criteria / Regimes	Frontier Land Canada	Alberta	British Columbia	Alaska	Norway
1. Acceptability	—	—	—	—	—
2. Neutrality	H	M	M	L	H
3. Mitigation at the Margin	H	M	M	L	H
4. Consistency	H	M	M	L	H
5. Robustness	H	M	M	L	H
6. Cost Recovery	H	L	L	L	M
7. Sharing of Risk	H	M	M	L	H
8. Optimizing Rent Extraction	H	M	M	L	H
9. Competition	—	—	—	—	—
10. Fiscal Interaction	—	—	—	—	—
11. Minimum Royalty	H	H	H	H	L
12. Consistency of Flow	M	M	M	H	L
13. Administrative and Compliance Efficiency	L	M	M	H	M
14. Certainty	L	M	M	H	L

LEGEND *H = High; M = Medium; L = Low*

5.0 Economic Comparison

5.1 Methodology

Estimating the amount of economic rent is a necessary precursor to an evaluation of a fiscal regime for establishing the portion of rent captured. Economic rent can only be measured in the context of a specific prospect. Different prospects will have different values because of differences in local geology, costs, etc.

In order to assess the efficacy of a fiscal regime of a jurisdiction in capturing the economic rent, the jurisdiction is divided into groups of prospects. Available economic rent is determined for each of the prospects and the regime is applied to each prospect to establish the rent captured from the prospect. Finally, the summation of economic rent and the rent captured from each of the prospects would give the total available economic rent and the total rent captured from the jurisdiction. This analysis would require extensive information regarding the geological prospects, costs, etc.

The above approach becomes more demanding if the objective is to conduct a comparative analysis of fiscal regimes from different jurisdictions. It may not be possible to readily obtain the relevant information economically.

An alternate approach for comparing the efficacy of fiscal regimes from various jurisdictions is to select prospects from a jurisdiction for which information is available and apply the fiscal regimes from different jurisdictions to these prospects. This approach will not give the total results for the jurisdictions, but will provide insight into the relative efficacy of the regimes under consideration. This approach is taken in this report for the comparative analysis of fiscal regimes from Frontier Lands, Alberta, British Columbia, Alaska and Norway.

In the analysis to follow, we take the prospects from the Frontier Lands that are of interest. We estimate the economic rent available in each of the prospects. We then determine the amount of rent that would be captured by the Frontier Lands regime and by the regimes in the comparison jurisdictions. We present the results at the level of the individual prospect.

We do not calculate total economic rent available and captured in any jurisdiction. We could calculate the totals for the Frontier Lands, however, for other jurisdictions we would have to include prospects that are representative of those jurisdictions.

5.2 Prospect Analysis

In determining the economic rent available from a specific prospect, one must consider the specific expenditures that a developer would make with respect to that specific prospect. This includes costs for land acquisition, exploration, exploratory drilling, construction of service infrastructure, operation, development drilling, and eventual abandonment. The revenues can be established by considering the probability of finding hydrocarbon and expectations regarding the price that those hydrocarbons will command in the market. There are also requirements to pay royalty, taxes, and financing costs. The costs and revenues do not occur uniformly over time, so present value adjustments are necessary so the monthly cash flows can be added together to give a summary expression of the available economic rent.

The following paragraphs we provide our conceptual model of a petroleum development. We describe the various types of expenditures, including the timing of the expenditures and the rate at which the expenditures appears in monthly cash flow statement. We also describe the measurement and timing of the revenues.

Land acquisition costs are the costs that are incurred to obtain the mineral rights. On Frontier Lands, mineral rights are awarded on the basis of a work expenditure bid. Although there is some cost associated with preparing a work bid, we make no specific recognition of these administrative costs because they are not material. In jurisdictions that use a bonus bid, the bid can be a significant cash outlay. In general, industry estimates the economic rent available and then offers a portion of the industry share of that rent as bonus. In this analysis, we have not examined biding behavior in detail. For those jurisdictions that use a cash bonus bid, we have estimated that the bid will be 10% of the industry share of economic rent. The land acquisition cost occurs in the first month of our analysis.

Geological and geophysical exploration costs include all those costs that industry incurs prior to drilling an exploration well. We consider that these costs occur at a constant rate during the interval between land acquisition and drilling an exploration well. These costs include the costs of public hearings and regulatory compliance. Although there is a chance that a lease might be abandoned without drilling, we ignore this probability.

Exploratory drilling occurs starting in a specific month. We estimate the probability that the exploratory well is successful. If the well is successful, it incurs completion cost. If it is not successful, it is abandoned as a dry hole.

For every successful exploratory well, there will be some dry holes. The cost of the dry holes must be covered by the revenue from successful developments. For each successful well, we estimate the cost of the dry holes. The estimate of the cost of each dry hole is the same as the cost of drilling the exploration well on the successful prospect, except that the dry holes will include abandonment cost instead of completion costs. We spread the dry hole cost over a reasonable period.

Development wells are treated essentially the same as exploratory wells, although the success rate is normally higher. For most developments, we assume all wells are drilled using a single drilling rig, so the development wells are drilled one after the other.

For gas developments, a gathering system and processing facility must be constructed before gas can be delivered to market. If there are delays in establishing pipeline connections, the development will see a period where it is incurring financing costs but has no revenue. There may also be other capital costs, such an access roads and security.

Once production has started, there will be operating costs. We split operation costs into costs that are fixed on a monthly basis and those that vary with the amount of production.

Production from the development will have a characteristic profile consisting of an initial rate of production that is constrained by the size of the infrastructure. The initial rate may be constant for a period, but eventually starts to decline as the resource is depleted. We use a decline function that is a percentage of the previous month's production.

Eventually production declines to the point where the value of production is less than the fixed operating costs. At that point the well shuts-in. It then incurs an abandonment cost.

In addition to the direct costs described above, industry also pays taxes, royalty, and financing costs. The tax and royalty payments are determined by the fiscal regime. The financing costs are determined by financial markets. Companies will differ in the extent to which they use debt financing or equity financing.

We split financing costs into a debt portion and an equity portion because the two types of financing have different rates and different tax consequences. Debt financing generally has the lower rate and results in interest expenses that are deductible from tax. Equity financing—i.e., the use of retained earnings—has an implicit cost equal to the minimum rate of return required by shareholders. This required minimum return will include a risk premium to compensate the shareholders for accepting greater risk.

Financing costs are only incurred before payout. After the development has achieved payout, the surplus may be re-invested in other projects or distributed to shareholders. The economic rent calculation implicitly assumes that the surplus is distributed to shareholders and consumed—i.e., there are no multiplier effects from reinvestment of profits.

After constructing the cash flow over the life of the development, we produce the total results in constant year dollars. The discount factor for this present value adjustment is a blend of the rates used for debt financing and equity financing. Hence the present value calculation represents the current price for a basket of annuities that could be purchased in the financial market and would duplicate the cash flow over the life of the development.

Expectations regarding inflation are built into the interest rates by the financial markets.

Exhibit 3 shows a graph of the cash flow over the life cycle of an example development. For simplicity, this graph uses broad categories of costs and shows annual cash flow instead of monthly flow. However, it shows the general effects of the various types of cost. There is a pre-production period where cash flow is negative, offset to some extent by tax reductions. This is followed by the production period where revenue greatly exceeds operation costs. However, the production and revenue declines, as the resource is eventually depleted.

Exhibit 3

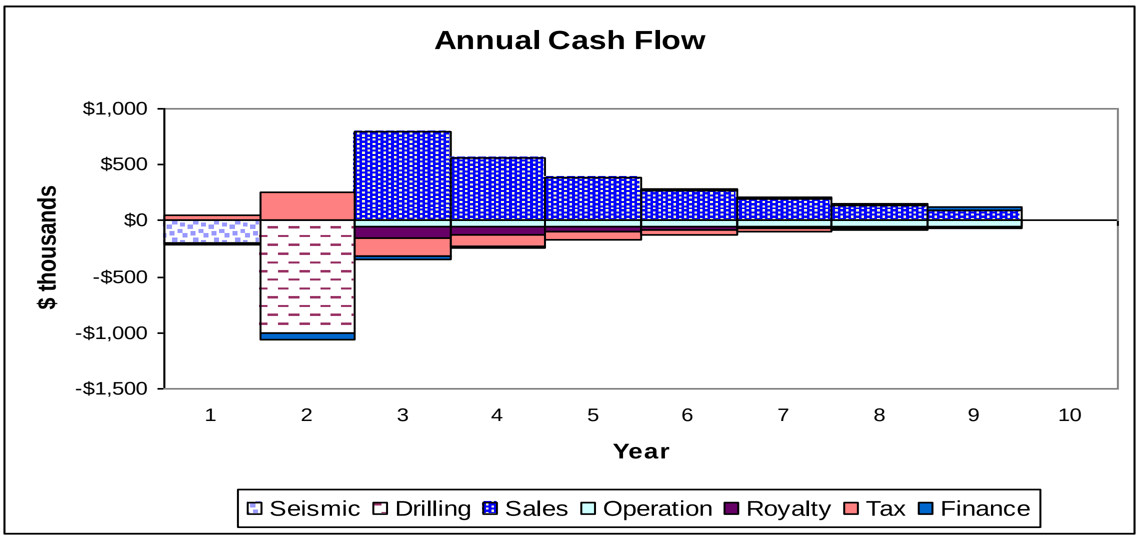


Exhibit 4, *following*, shows the net present value of the cash flows from this example. The distribution of economic rent is shown in Exhibit 5, *following*. The general tax is a cost but not part of economic rent. We show the tax as well as the landowner share because we are interested in comparisons of total take where the government is the landowner.

Exhibit 4

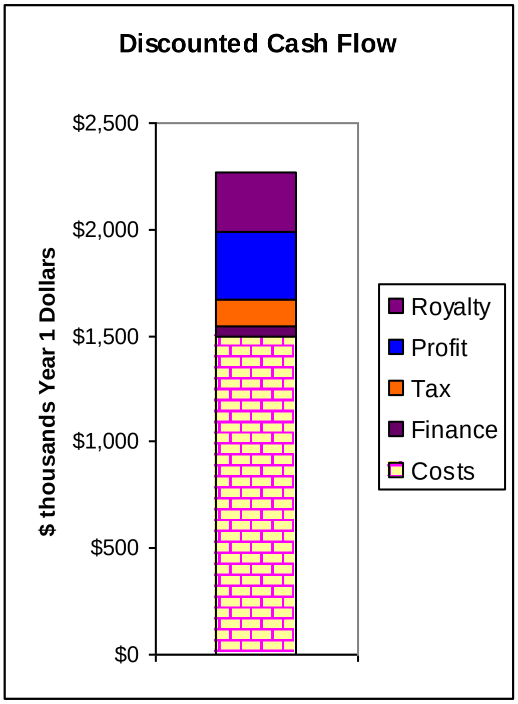
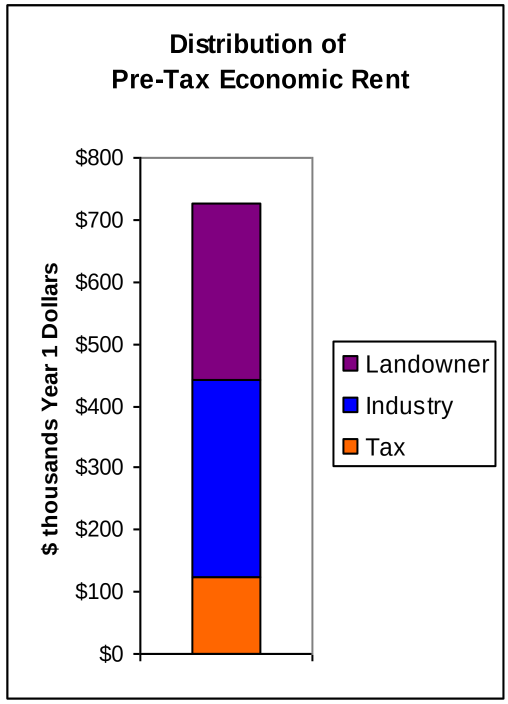


Exhibit 5



5.3 REAM

In order to calculate economic rent available, this analysis uses a model called REAM (Regime Economic Analysis Model). This is a monthly iterative model that simulates the cash flows over the life cycle of a development. REAM duplicates the monthly production reports from a development and the related monthly income statements for a corporation, including details of tax liabilities, royalty, and interest payments. Closing balances from one month are then used as inputs for the subsequent month. The model takes as inputs various estimates including play size, production profile, costs, success rates, interest rates, and prices.

REAM also distributes the cash flows between industry, the landowner, and the tax authority. The economic value of these cash flows is expressed in terms of the dollars of a reference year. The economic rent available is then computed as the present value of revenues minus the present value of the costs incurred to generate that revenue.

REAM is designed to be flexible in considering changes to specific aspects of the tax, royalty, and land tenure administration. REAM also includes several timing variables.

In order to perform the tax calculations, REAM makes specific assumptions about the corporation's tax situation and about its sources of finance. In particular, established companies will be able to take immediate advantage of tax losses in the early phases of the development because the losses will offset tax payable on other developments. Also the extent to which a corporation uses bond financing instead of equity financing affects the tax calculation.

6.0 Comparative Assessment of Fiscal Regimes

6.1 Comparison Prospects

In order for comparisons to be meaningful in relation to prospects that may be developed on the onshore Frontier Lands, we analyzed four prospects. Each prospect was considered with two price levels. This provides a total of eight cases.

The comparison prospects reflect the actual geology of the area. Where available, the geological knowledge is supplemented by actual production histories. The four comparison prospects provide a realistic range of the actual production and costs that would be considered by a corporation considering exploration in the North.

All of the prospects are gas prospects. This reflects the expectation that exploration targets are overwhelmingly gas prone. Each prospect is simulated as a pool of a specific size from the remaining undiscovered pools in a specific geological play.

The following is a brief description of the geological plays from which the prospects were selected. The first three plays are in the southern territories and described in the National Energy Board's "Resource Assessment of Southeast Yukon and Northwest Territories," published in 1996. The fourth is in the northern plains.

1. Beaver River

This prospect is the largest of the expected remaining undiscovered resource in the Play identified as the Beaver River - Laramide Structures (middle Devonian Carbonates). This is an established geological play. The geological information available in the 1996 geological assessment is supplemented by actual production history from the K-29 pool. This benchmark is clearly economic, near the upper end of pools that are yet to be discovered.

2. Windflower

This prospect is representative of expected discoveries in the Play identified by the National Energy Board (NEB) in 1996 as the Laramide Structures – Mesozoic Clastics/Carbonates (Windflower/Tatoo). NEB considered this to be a conceptual geological play, with no current discoveries. However, the production profile is expected to be similar to the F-36 pool. The analysis is run with the capital development for gas processing replaced by a custom processing fee of $0.75 per mcf. This comparison is a marginal development, near the bottom of prospects expected to be profitable.

3. Upper Keg River

This prospect is the tenth largest of the expected remaining undiscovered resource in the Play identified by NEB as the Upper Keg River (Pine Point) Black Barrier – Cameron Hills. This is a mature established geological play, with all large pools in the play already discovered. The prospect was expected to be a "marginal" development near the bottom of the range of developments likely to be economic. The analysis shows that the prospect is not economic. However, at the higher price, development would be profitable for industry under the Frontier Lands regime.

4. Colville – Cambrian Sandstone

This is modeled as a tight gas reservoir. The Colville area is further north than the area considered by the NEB in 1966. This analysis assumes[4] a reasonably large reservoir, but with low flow rates per well. The rate of decline is also low, so that the prospect has a long productive life. The prospect is economic under the given parameters, but takes several years to achieve payout. The prospect incurs significant financing costs, so the economic viability is significantly affected by the interest rate and the rate of return required for equity capital.

* * *

6.1.1 Prospect-Specific Variables

In Table 1, *following*, we show the detail input variable used in the analysis. Note that any three of the variables pool size, initial production rate, plateau period, and decline rate; determines the fourth.

[4] The selected model parameters do not necessarily reflect actual or specific prospects for which new drilling information remains confidential.

Table 1
Input Matrix for Comparison Prospects

Prospect	Beaver River	Windflower	Upper Keg River	Colville
Pool Size ; Bcf Marketable Gas	178	10	11	50
Number of Wells	4	1	2	5
Initial Production Rate, Marketable Gas in mmcf per day	70	5.5	4.3	12
Gas Plateau Period in months	36	24	36	60
Gas Decline Rate % per month	2%	2.7%	2%	1%
G&G Cost	$6,000,000	$2,000,000	$3,000,000	$3,500,000
G&G period in months	24	12	24	24
Probability Explorative Success	.3	.4	.3	.4
Drilling and Completion Cost of Exploratory Well	$10,000,000	$3,500,000	$3,500,000	$4,000,000
Drilling and Completion Cost of Development Well	$6,000,000	$2,000,000	$1,500,000	$2,000,000
Probability of Development Success	.8	.6	.6	.8
Gas Plant Capital	$3,782,000	0	$4,000,000	$4,000,000
Gathering Capital	$7,031,000	0	$7,000,000	$7,000,000
Monthly Fixed Operation per well	$5,000	$5,000	$5,000	$5,000
Variable Operation gas per mcf	$0.15	$.15+.75 Processing Fee	$0.15	$0.15
Gas Transportation Costs to pricing point per mcf	$0.62	$0.60	$0.60	$0.60

6.1.2 Generic Variables

The variables relate to general assumptions necessary to compute taxes and monthly cash flows:

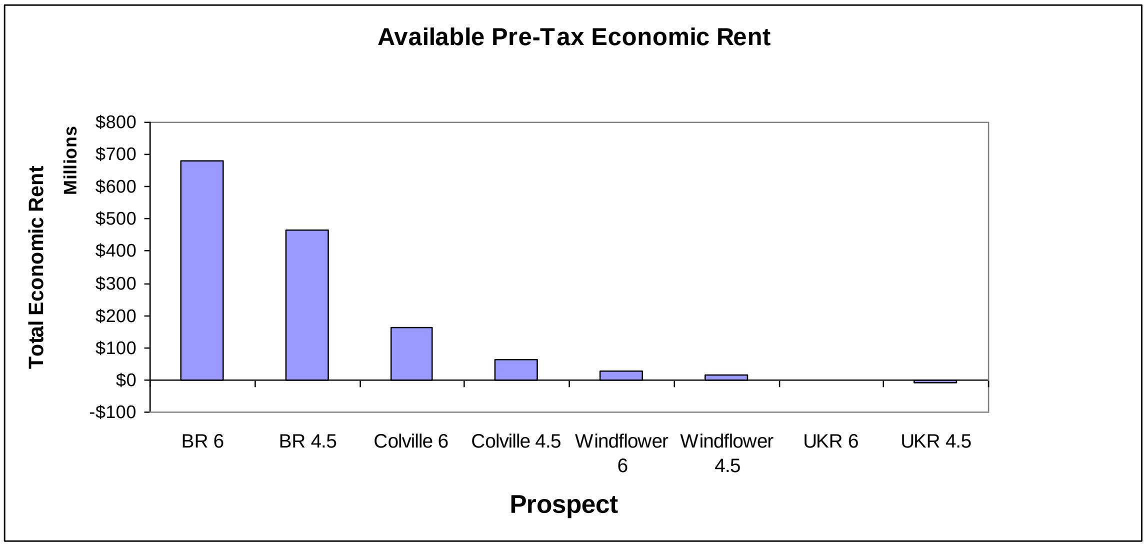
- Inflation forecast 2% per year.
- Gas price forecast is flat real. Analysis is run twice; once with a Canada/US export price of $4.50 per mcf and again with a price of $6.00 per mcf. In each case, the plantgate price is reduced by transportation costs to a pricing point equivalent to the border.
- Large company assumption:
  - Industry Cost of Debt Capital equals Bank of Canada long-term bond rate plus 0.5%. Value used is 3% per year.
  - Industry Cost of Equity Capital equals Cost of Debt Capital plus 3%.
  - Financing is 80% Equity, 20% Debt
  - Tax situation allows exploration costs to generate immediate tax reductions
  - Going concern—abandonment costs generate tax reductions.
  - Abandonment Capital Cost of $50,000 per well occurs three years after well is shut in.
- Dry hole costs are spread over the initial five years of the development. Dry hole costs are assumed to be “off lease.” They are used in tax and financial flow calculations, but not in payout calculations. On Frontier Lands, dry holes generate royalty credits.

6.2 Results for Frontier Lands

Exhibit 6, *following*, shows graphically the distribution of the available economic rent for the comparison prospects. The prospects are arranged in order of decreasing economic rent. The label “4.5” or “6” shows the price scenarios for $4.50/mcf and $6.00/mcf.

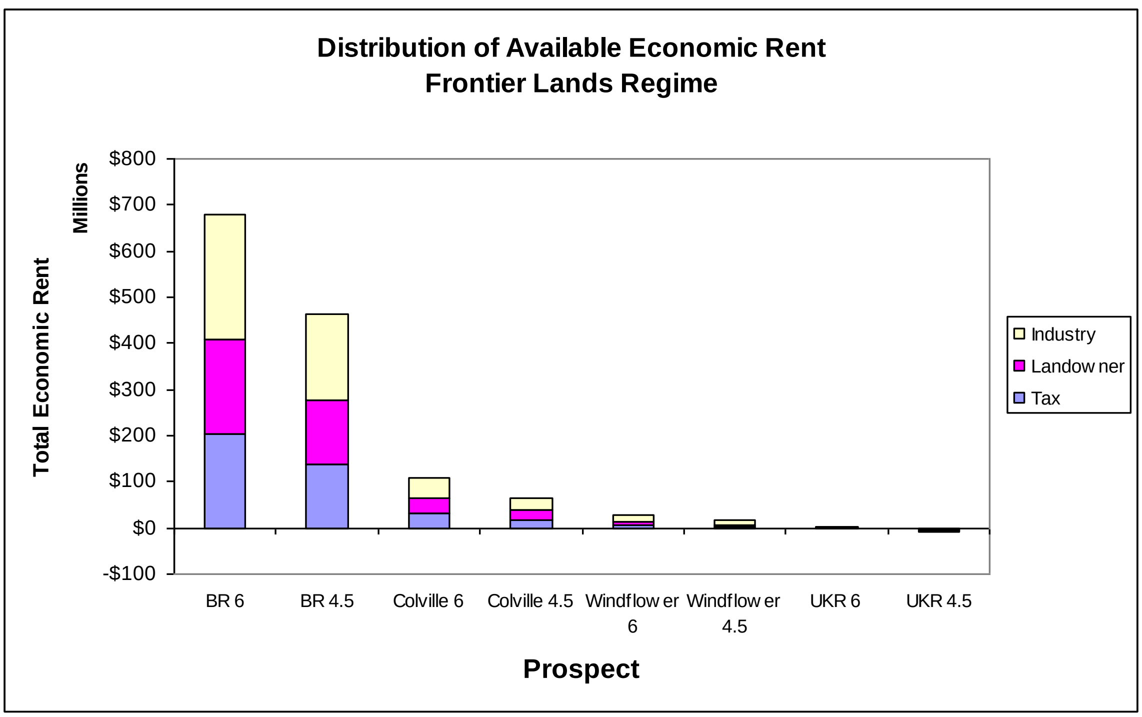
Upper Keg River has negative economic rent at both of the price scenarios considered.

Exhibit 6



The economic rent available depends only on the prospect. The distribution of the available rent varies with the regime. Exhibit 7 shows the distribution of the economic rent under the Frontier Lands regime.

Exhibit 7



The values shown in Exhibit 7 (previous) are given in Table 2:

Table 2

	Distribution of Economic Rent Available							
Prospects	**BR 6**	**BR 4.5**	**Colville 6**	**Colville 4.5**	**Windflower 6**	**Windflower 4.5**	**UKR 6**	**UKR 4.5**
Industry	$273,668,607	$188,864,115	$45,186,594	$26,735,830	$14,106,157	$8,868,724	$213,801	-$5,160,7557
Land Owner	203,473,605	138,346,419	33,184,677	20,347,281	7,846,217	3,927,786	1,201,033	0
Tax	203,631,084	136,784,109	31,110,060	17,320,345	7,300,536	3,245,363	-2,168,614	-4,480,431

The effect of the tax regime on the economics of the last two cases is negative. This negative value represents the value of the losses transferred to reduce tax payable on other developments.

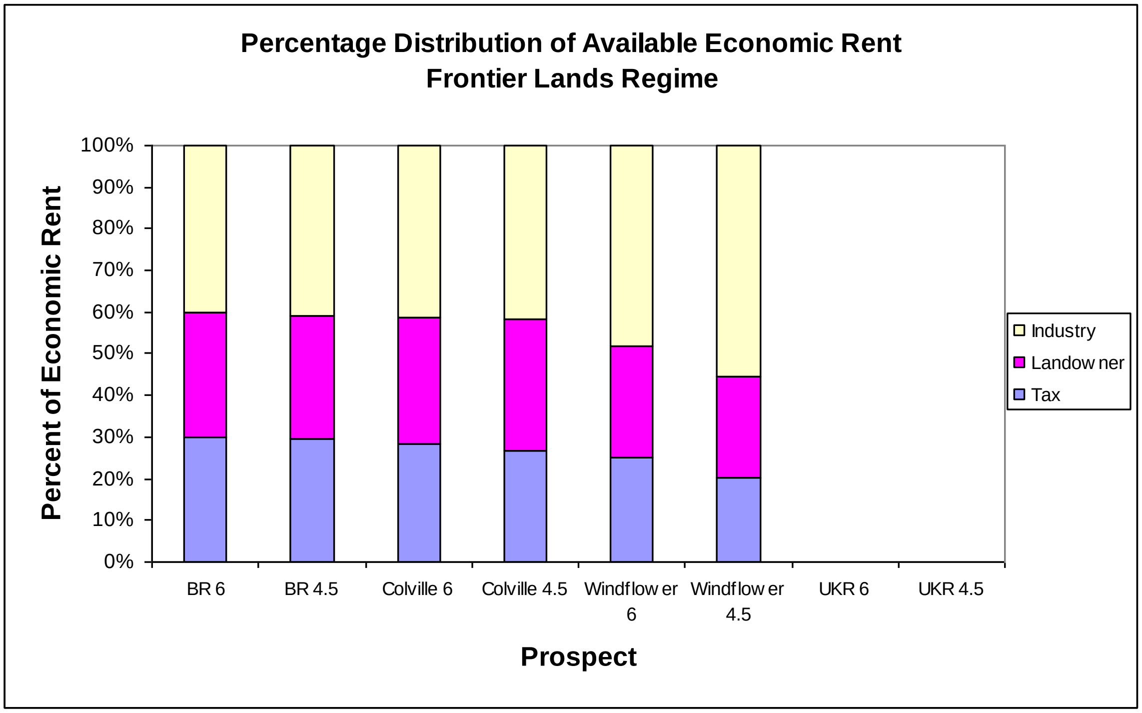
In the case of the Upper Keg River prospect at $4.50/mcf, the tax offset $4.5 million of the loss. In the case of the Upper Keg River prospect at $6.00/mcf, the tax benefit of $2 million was enough to generate positive return for industry on this development that is basically uneconomic.

The tax benefit arises primarily because industry pushes some of its negative cash flow into the future while obtaining tax benefit as if the expenditure was immediate. In particular, industry benefits from the immediate deductibility of Canadian Exploration Expenses (CEE) and rapid deductibility of Canadian Development Expense (CDE). However, industry will push some of these expenditures to the future by financing. The interest expense incurred will also be deductible from tax. The present value of the tax reduction from the immediate recognition of drilling costs plus the tax reduction from the recognition of interest expense exceeds the present value of the actual industry cash flow that consists of immediate partial payment of drilling costs, plus payment of the balance of drilling costs as repayment of a loan principle and interest over a period of time.

In our analysis we used only 20% debt financing and required immediate recognition of exploration and drilling expenses. Cash outlay was delayed only for the gas processing facility. However, the Upper Keg River prospect never achieves payout, so the interest expense becomes significant.

Exhibit 8 shows the percentage distribution under the Frontier Lands regime. We omit the percentages for the last two prospects because the available rent is negative.

Exhibit 8



The general trend is for industry to receive a larger share of the available rent as the value of the prospect declines. Tax takes a smaller share as the value of the prospect declines.

It is worth noting that the percentage share for the Colville prospect taken by royalty is higher under the $4.50 price than under the $6.00 price. This happens because the Colville development produces significant amounts of gas after payout where the 5% ad valorem royalty is higher than the 30% resource rent royalty. This is in turn caused by the fact that the production profile for Colville involves a slow decline rate.

Table 3 shows the data in Exhibit 8 in table form. It also includes a line "Government" that is the sum of the Tax and Landowner values.

Table 3

	Percentage Distribution of Pre-tax Rent					
Prospects	**BR 6**	**BR 4.5**	**Colville 6**	**Colville 4.5**	**Windflower 6**	**Windflower 4.5**
Industry	40.5	41	41	42	50	57
Land Owner	29.5	29	30	32	24	22
Tax	30	30	29	26	26	21
Government	60	59	59	58	50	43

For the largest prospect (Beaver River), there is little difference in percentages between the low price and high price case. The percentage taken as tax and as royalty is near the maximum marginal rates. The landowner share over the total life of the development is near the specified 30% post-payout share of net revenue. The tax is approaching a rate that is just above 30% and is the combined effect of federal tax, surtax, large corporation tax, NWT corporate tax, and federal sales tax.

The total "Government" share of 60% is useful when comparing regimes where there are substantial differences in tax as well as in royalty. The amount of economic rent that the government leaves to industry provides both an incentive to industry and a margin for error. To the extent that there are barriers to entry, the extra rent helps to overcome these barriers. In particular, giving industry a higher share of rent may be necessary to attract new investors.

However, it is important to note that as long as the government share is below 100%, then there is some incentive for industry to invest. The underlying principle in the concept of economic rent is that all prospects with positive economic rent will be developed. The economic rent calculation implicitly includes competition from all other investments because it includes a general cost of capital. Risk is also included because all investment instruments already include the financial market's estimation of the associated risk.

6.3 Inter-Regime Comparisons

The following is a comparison of the distribution of economic rent for each prospect between the different regimes.

6.3.1 Beaver River 6

Exhibit 9 provides the amount of economic rent taken by the governments and industry and Table 4 provides the percentage of economic rent shared between government and industry.

Exhibit 9

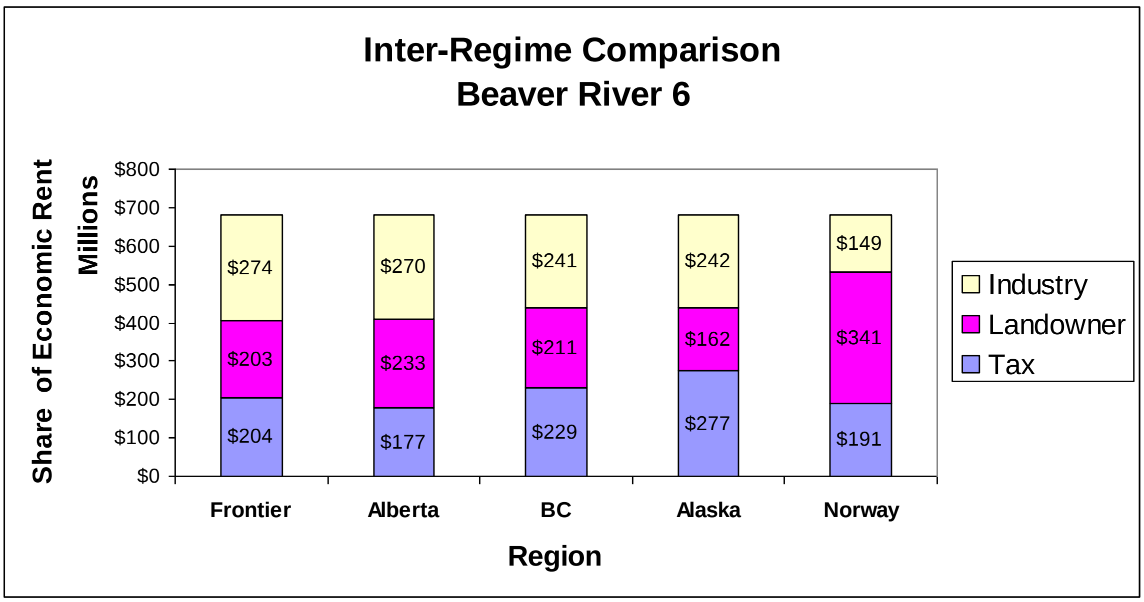


Table 4

Region / Prospects	Inter-Regime Comparison				
	Frontier Lands	**Alberta**	**B.C.**	**Alaska**	**Norway**
Industry	40%	40%	35%	35%	22%
Land Owner	30%	34%	31%	24%	50%
Tax	30%	26%	34%	41%	28%

The Beaver River prospect at $6.00/mcf offers $681 million in economic rent and achieves payout within the first year of production. The economic rent captured by each regime is essentially equal to the limiting rates in the various formulas.

The share of rent captured by Norway is considerable higher than the share captured by the other regimes. Most of the total government share in Norway is from the 50% tax on oil and gas profits. Norway's income tax takes 28% of the pre-tax rent, making the Norway background tax second lowest, after Alberta.

The total government share under the Frontier Lands and Alberta regimes are similar. Both take 60%, leaving industry 40%. However Alberta takes a larger landowner share. The large landowner share for Alberta is due to the fact that Alberta's regime does not consider costs. When applied to a high cost development, Alberta's royalty regime takes a higher share than it would when applied to the relatively low cost Alberta developments.

The tax difference arises because royalty is now deductible from costs when computing corporate tax. Hence a higher royalty results in lower tax. Alberta's tax rates are less than the NWT rates, but the difference is only 1%. Most of the tax difference is directly due to the higher royalty.

British Columbia and Alaska both take 65% of the pre-tax rent, leaving industry 35%. Both take less royalty than Alberta, but have higher taxes.

British Columbia shows a higher tax share because it imposes a Provincial Sales tax of 7.5% plus has a corporate tax 2% higher than Alberta. This 9.5% difference in tax more than offsets the fact that British Columbia's royalty rate is 3% lower.

Alaska has the lowest royalty of all the regimes, but the highest tax. The Alaska tax regime includes a Federal corporate tax rate that is effectively 10 percentage points higher than the Canadian Federal rate. In addition Alaska imposes a state severance tax on oil and gas production that in this development takes $60 million.

6.3.2 Beaver River 4.5

Exhibit 10, *following*, provides the amount of economic rent taken by the government and industry, and Table 5, *following*, provides the percentage of economic rent shared between government and industry.

Exhibit 10

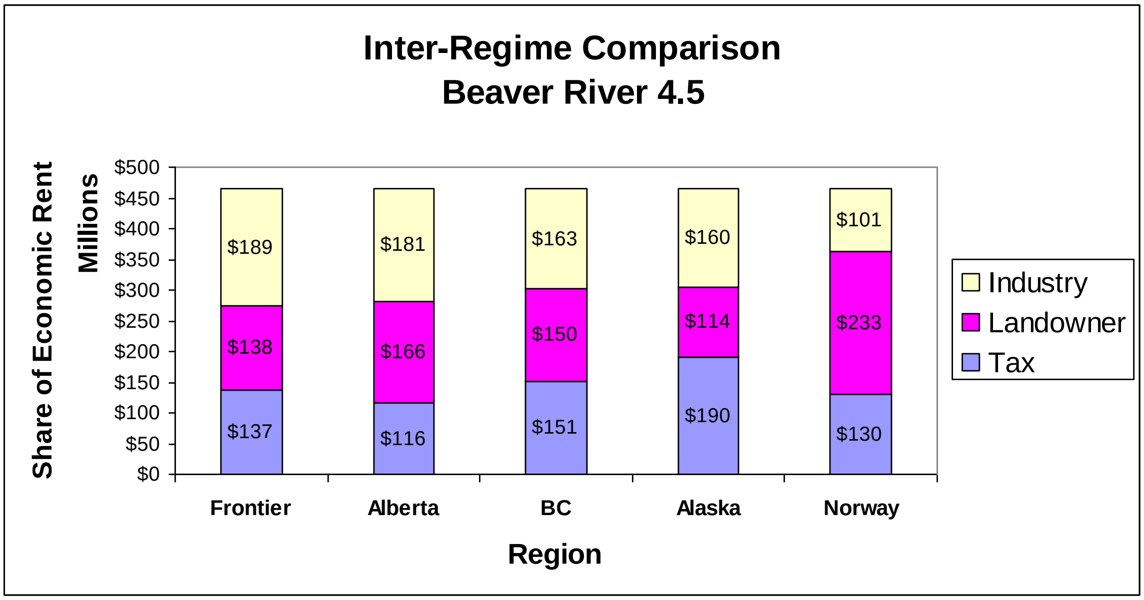


Table 5

Prospects \ Region	Inter-Regime Comparison				
	Frontier Lands	**Alberta**	**B.C.**	**Alaska**	**Norway**
Industry	41%	39%	35%	35%	22%
Land Owner	30%	36%	32%	25%	50%
Tax	29%	25%	33%	41%	28%

The Beaver River prospect at $4.50/mcf provides $464 million in economic rent. The percent of rent captured by each regime is very close to the percent captured under the $6.00 price. The rates continue to be close to the limiting rates for each regime.

There is a slight decrease the government take percentage under the Frontier Lands regime and a slight increase under the Alberta regime. Both shifts are due to the fact that cost becomes relatively more important when revenue is lower. Under the Frontier Lands royalty, the payout point is delayed, so there is a decrease in the effective royalty rate. Under the Alberta royalty regime, the royalty rate is unchanged as a percent of total revenue, but becomes a higher percentage of pre-tax rent.

The fact that the rate goes down when the price goes down is a good feature of the Frontier Lands regime. The fact that the rate goes up when the price goes down is a poor feature of the Alberta regime. Alberta's royalty rates are sensitive to price, but not in the price range considered here.

British Columbia and Alaska both take a slightly higher percentage for the land owner. This shift is the same direction as the shift for Alberta, and occurs for the same reason. The British Columbia and Alaska royalty formulas are not sensitive to cost, and are taking the same percent of total revenue as they did at $6.00.

For each of Alberta, British Columbia, and Alaska, the higher percentage taken by royalty is offset by a lower percentage taken by tax, so that the total government percentage does not change as much as the landowner percentage. In each regime, the corporate tax goes down because royalty when up—the royalty is deducted as a cost when computing the tax.

The percentage share for Norway is not affected by the price change. Like Frontier Lands, the Norway regime adjusts automatically to changes in price. The Norway regime continues to take economic rent at the marginal rate of 50% for landowner and 28% for tax.

It is worth noting that both the Norwegian oil and gas tax and the income tax are similar calculations. They are also both technically going to the tax authority. We classify the Norwegian oil and gas tax as "land owner" share because (1) the Norwegian government considers this to be compensation to the people of Norway for extraction of the resource, (2) the rate is set specifically to achieve certain oil and gas development objectives, and (3) the rate does not consider any immediate revenue needs to finance general government functions

6.3.3 Colville 6

Exhibit 11, *following*, provides the amount of economic rent taken by the government and industry, and Table 6, *following*, provides the percentage of economic rent shared between the government and industry.

The Colville prospect at $6.00/mcf provides $109 million in economic rent. It achieves payout after four years. This is still a good prospect, but has a higher ratio of cost to revenue than the Beaver River prospect. The regimes that have royalty formulas that ignore costs (Alberta, British Columbia, and Alaska) give the landowner a higher share of economic rent.

Exhibit 11

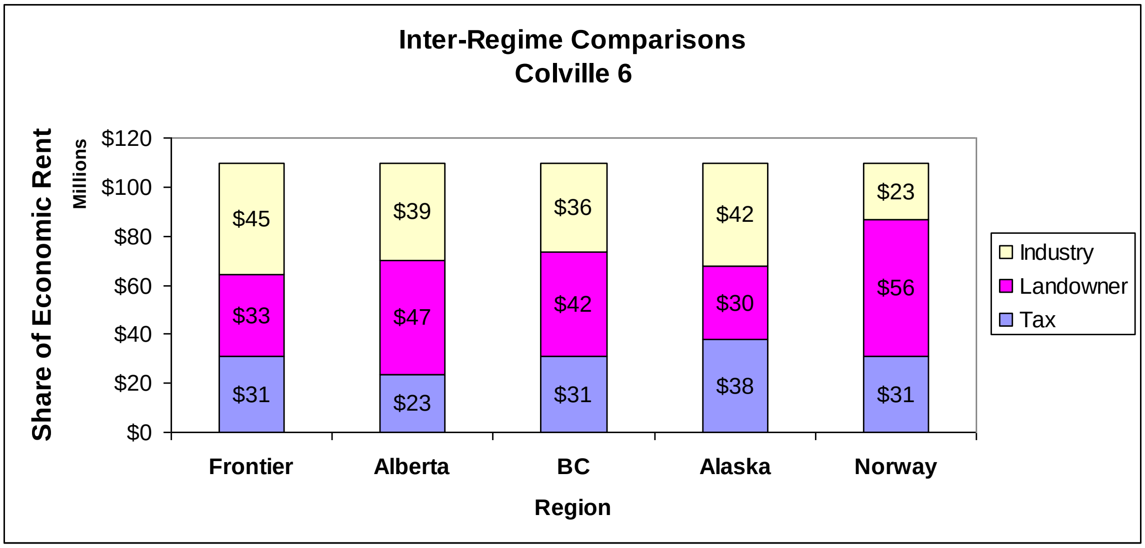


Table 6

Region / Prospects	Inter-Regime Comparison				
	Frontier Lands	**Alberta**	**B.C.**	**Alaska**	**Norway**
Industry	41%	36%	33%	38%	21%
Land Owner	30%	43%	38%	27%	51%
Tax	28%	21%	28%	35%	28%

The regimes that measure costs (Frontier Lands and Norway) take about the same percentage share of rent. The percentage share is actually slightly higher than for Beaver River. The slight increase is due to the fact that this is a tight reservoir, with a slow rate of production decline. The production is spread over a longer time period. In the case of the Frontier Lands regime, it results in there being some significant production that occurs after payout but where the 5% ad valorem royalty is higher than the 30% resource rent royalty. In the case of Norway, accelerated deprecation and cost uplift rules in the calculation have less effect because of the longer productive life. Although the Norway regime accepts interest expense as a cost, its uplift provisions in this case do not fully reimburse industry for the cost of equity capital.

There is a larger difference between Frontier Lands and Alberta for this prospect than for the Beaver River prospect. For the more profitable Beaver River prospect, the Frontier Lands and Alberta regimes had essentially the same government share. Both left industry 40%. For Colville, the Frontier Lands regime is now five percentage points better than Alberta. This difference is almost entirely due to the increased share taken by the Alberta royalty formula.

The Alaska regime moves into second place in terms of being favourable to industry. The percentage taken by royalty in Alaska went up two percentage points, but this was more than offset by a six percentage point drop in the amount taken by tax. The reduction in tax is mostly due to a reduced severance tax. The Alaska severance tax is sensitive to well rate of production. It disappears for wells that produce less than 300 mcf per day. The low producing wells in this tight reservoir pay no Alaskan severance tax.

The British Columbia regime, like the Alberta regime, takes a higher percentage share for the landowner and leaves less for industry.

6.3.4 Colville 4.5

Exhibit 12 provides the amount of economic rent taken by government and industry and Table 7, *following*, provides the percentage of economic rent shared between government and industry.

Exhibit 12

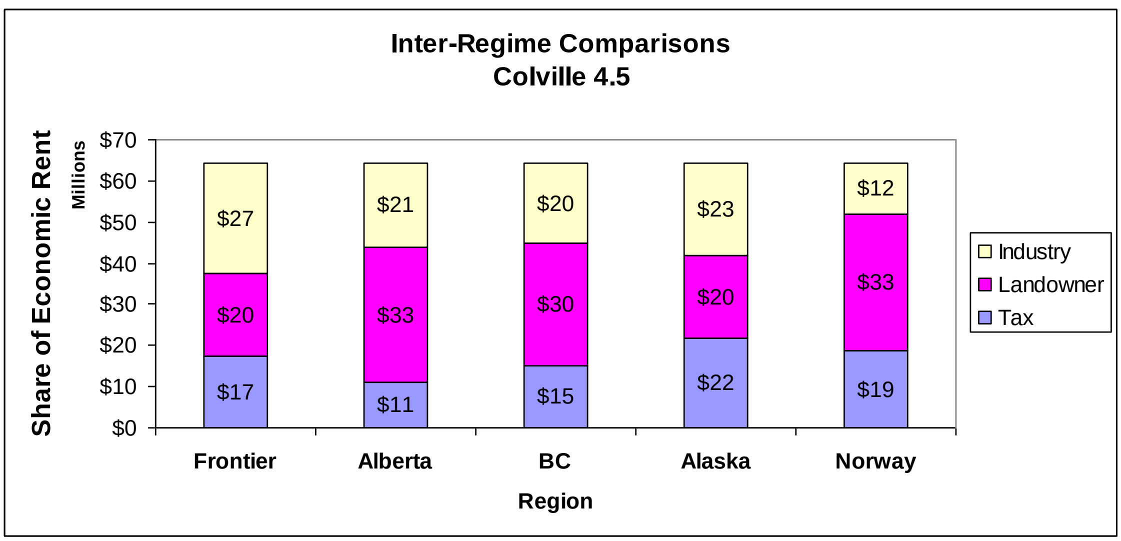


Table 7

Region / Prospects	Inter-Regime Comparison				
	Frontier Lands	**Alberta**	**B.C.**	**Alaska**	**Norway**
Industry	42%	32%	30%	35%	19%
Land Owner	32%	51%	46%	31%	52%
Tax	27%	17%	23%	34%	29%

The Colville prospect at $4.50/mcf provides $64 million in economic rent. It achieves payout in Year 6.

Compared to the same prospect at $6.00, the Frontier Lands regime takes a slightly higher percentage for the landowner, but a lower percentage for tax. The landowner increase is due to the prospect having relative more production subject to the 5% minimum ad valorem royalty after payout. However, this increase is offset by an even larger decrease in corporate tax, so that the percentage left for industry increases one percentage point, to 42%.

In terms of the percentage left for industry, the Frontier Lands regime is now 10 percentage points higher than Alberta. The Alberta regime now takes 51% of the available rent for the landowner—up 8 percentage points from the share at $4.50/mcf. The Alberta regime is taking the same percentage share of revenue. However because this prospect has a higher ratio of costs to revenue, the constant percentage of revenue represents a higher percentage of available economic rent.

The 8 percentage point increase share taken by the Alberta landowner is somewhat offset by a 4 percentage point decrease in the share taken by tax. The share remaining to industry is down 4 percentage points.

British Columbia follows much the same pattern as Alberta. Land owner share is up by 8 percentage points because the royalty formulas are not sensitive to cost. Tax is down both because tax is sensitive to cost and because tax includes royalty as a cost. Tax is relatively more important in British Columbia, with the share taken by tax drops by 5 percentage points. The total reduction in the share for industry under the British Columbia regime is 3 percentage points.

Alaska follows the same pattern as Alberta and British Columbia. Land owner share increases 4 percentage points, tax decreases 1 percentage point, and industry share decrease 3 percentage points.

The price sensitivity exhibited by the Alberta, British Columbia, and Alaska regimes is backward for this prospect. The regimes take a higher share of rent when the price is lower.

For Norway, the percentage for both landowner and tax increases. The increase is due to the fact that the cost uplift provisions are not sufficient to offset industry's cost of equity capital. Payout in this prospect takes longer than at $6.00/mcf. Industry's cost of equity capital is thus higher. The Norway regime directly recognizes only interest expense as a financing cost. The regime is not sensitive to the increase in the amount required to finance industry's pre-payout cost of equity capital.

6.3.5 Windflower 6

Exhibit 13 provides the amount of economic rent taken by government and industry and Table 8, *following*, provides the percentage of economic rent shared between government and industry.

Exhibit 13

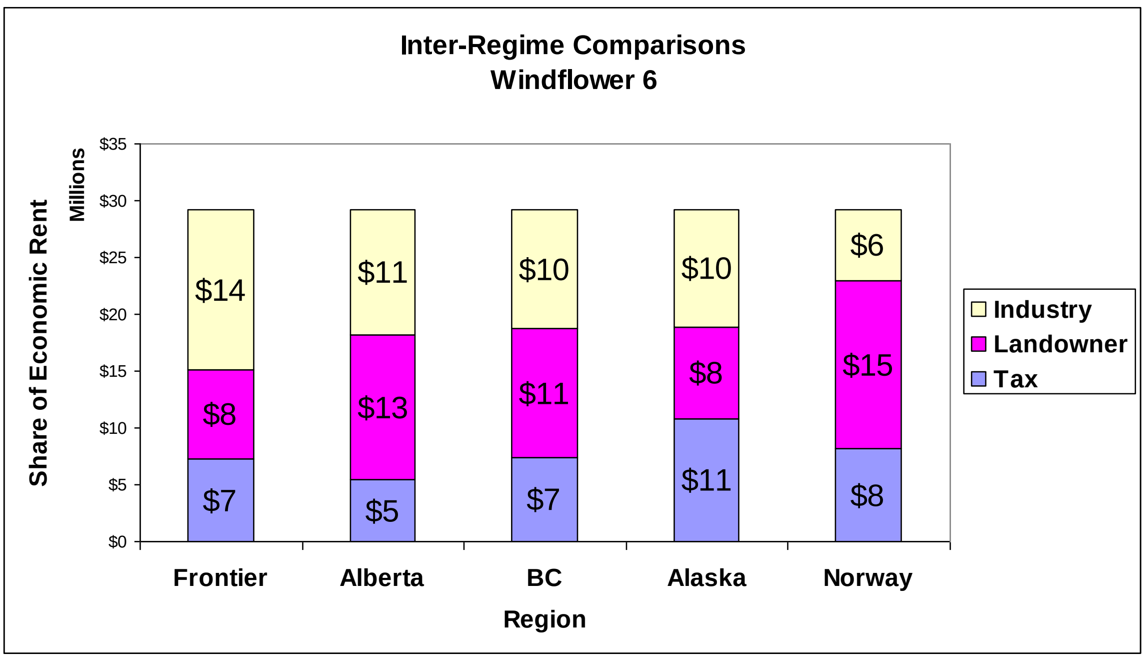


Table 8

Region / Prospects	Inter-Regime Comparison				
	Frontier Lands	**Alberta**	**B.C.**	**Alaska**	**Norway**
Industry	48%	38%	36%	35%	22%
Land Owner	27%	43%	39%	28%	50%
Tax	25%	19%	25%	37%	28%

The Windflower prospect at $6.00/mcf has economic rent of $29 million. It achieves payout in Year 3. This development is simulated as having custom processing charges for gas instead of the capital costs. This prospect has the shortest life of the four considered. The exploration period is only 12 months. The well rate of production starts declining sooner and declines faster.

The percentage royalty under the Federal regime is 3 percentage points lower than the limiting rate. Although the prospect achieves payout fairly quickly, there is still a substantial amount of production in year two that either has a royalty holiday or pays the minimum 1%. The landowner share of economic rent is five percentage points less than for the Colville 4.5 prospect. The tax share is two points less, so that the industry share goes up by seven percentage points.

The Alberta and British Columbia regimes both take a smaller share of economic rent from this development than they did from the Colville 4.5 prospect. This is because the Windflower 6 development has a lower cost per mcf than the Colville development. Lower cost per mcf means there is more economic rent available per mcf. Regimes that take a constant share of sales revenue take a lower share of economic rent.

Alberta is now the second most favourable regime—the same ranking as for the Beaver River development. However, the gap between the Frontier Lands Federal regime and the Alberta regime is now much greater. The Frontier Lands regime leaves industry almost half of the economic rent—11 percentage points more than the 28% left by Alberta.

Alberta, British Columbia, and Alaska are now all close to each other in terms of the percentage of economic rent left to industry. Although Alaska has lower royalty, the severance tax on this development is significant—it represents 5% of the pretax economic rent.

Norway takes from this development the same percentage share as from the Beaver River development. The cost uplift provisions in the Norway regime are sufficient to cover industry's small pre-payout cost of equity finance.

6.3.6 Windflower 4.5

Exhibit 14 provides the amount of economic rent taken by government and industry and Table 9 provides the percentage of economic rent shared between government and industry.

Exhibit 14

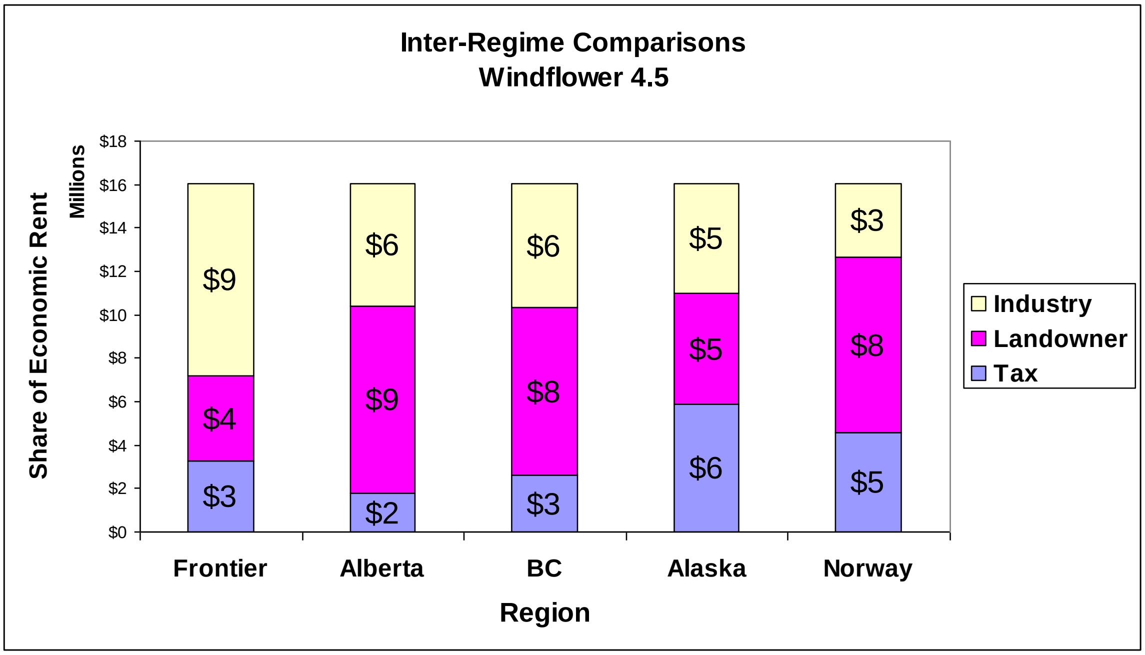


Table 9

Region / Prospects	Inter-Regime Comparison				
	Frontier Lands	**Alberta**	**B.C.**	**Alaska**	**Norway**
Industry	55%	35%	35%	32%	21%
Land Owner	24%	54%	48%	32%	51%
Tax	20%	11%	16%	37%	28%

This Windflower prospect at a price of $4.50/mcf has positive economic rent of $16 million. It reaches payout in Year 4.

In comparison to the same prospect at $6/mcf, the Frontier Lands regime now takes seven percentage points less of the pre-tax economic rent, leaving industry with 55%.

The Alberta, British Columbia, and Alaska regime all give the landowner a higher percentage share of available rent at $4.50 than they did at $6.00. The landowner share is up eleven points in Alberta, nine in British Columbia, and four in Alaska. This increase is partially offset by a decrease in the tax share. The net effect is to give industry a share that is down three points for Alberta, one for British Columbia, and three for Alaska.

The price sensitivity exhibited by the Alberta, British Columbia, and Alaska regimes is backward for this prospect. The regimes take a higher share of rent when the price is lower.

The results for Norway are almost the same as for the case at $6/mcf. There is a slight increase in landowner share. At the slightly longer payout, the cost of equity financing is higher. Since this cost is not recognized in the Norwegian calculations, the result is to increase Norway's percentage share of economic rent.

6.3.7 Upper Keg River 6

Exhibit 15, *following*, provides the amount of economic rent taken by government and industry and Table 10, *following*, presents the amounts in table form[5].

At $6/mcf, the Upper Keg River prospect is uneconomic. It would provide negative economic rent of $754,000. It never achieves payout.

The development would nevertheless proceed under the Canadian Lands regime. Industry receives a subsidy of $2.17 million in the form of tax benefits. Industry would pay $1.2 million in royalty, but would retain $214,000. As discussed earlier, the subsidy arises because industry gets benefit of immediate tax recognition of capital costs but moves some of the negative cash flow into the future through financing.

[5] *We omit the percentage table because the economic rent is negative. The percentages have this negative number as denominator. They have opposite sign to the share taken (which is the numerator). They have little information value except for people with degrees in mathematics. The percentages can be computed as the numbers given in table 10 divided by (minus 754000).*

Exhibit 15

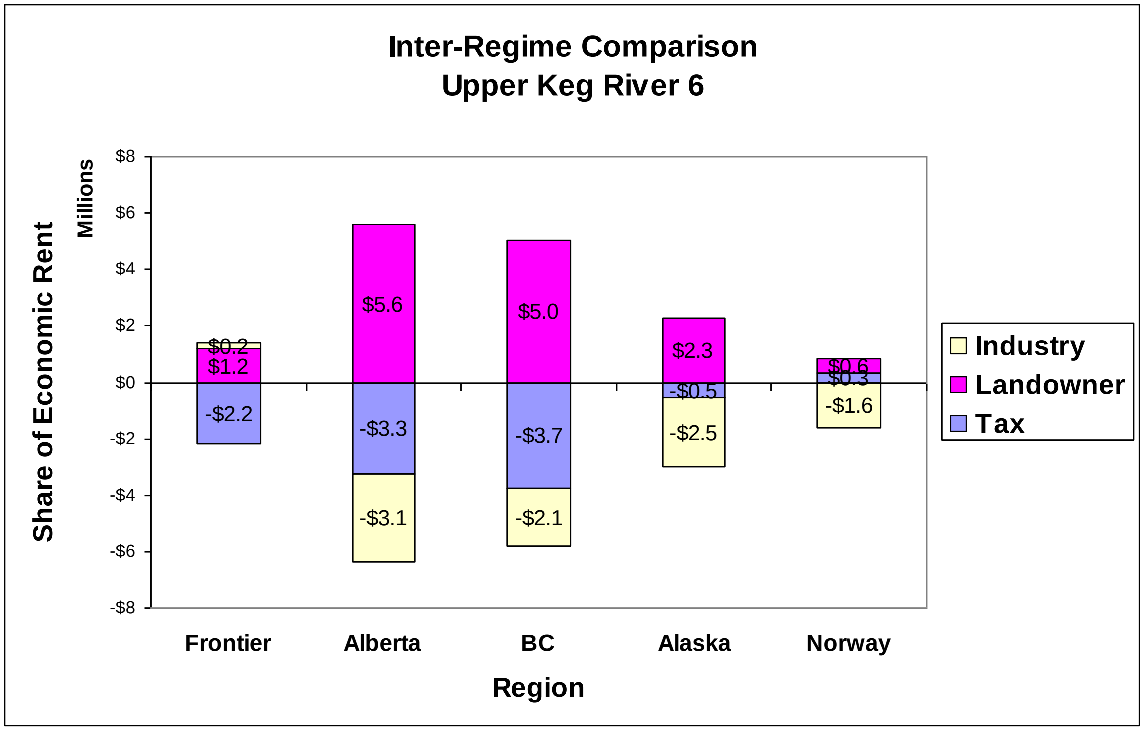


Table 10

Prospects \ Region	Share of Economic Rent ($ Millions)				
	Frontier Lands	**Alberta**	**B.C.**	**Alaska**	**Norway**
Industry	$0.21	-$3.10	-$2.06	-$2.50	-$1.62
Land Owner	$1.20	$5.60	$5.04	$2.26	$0.55
Tax	-$2.17	-$3.26	-$3.74	-$0.52	$0.31

One possible justification for having the tax regime allow an uneconomic development to proceed is the multiplier effects that arise in the economy. The economic rent calculation does not include the multiplier effects in the economy that arise when the development proceeds. If the value of industry re-investment is added, then the development shows a positive total benefit to the economy. The tax authority will recover its loss through taxes on individual incomes and other employment related effects. Although it would be better to channel the dollars to a more profitable venture, the fact that the development would add infrastructure and employment can be justification for setting tax parameters to encourage development of such marginal prospects. Note also that the landowner does not receive revenue from these multiplier effects, whereas the tax authority does receive such benefit.

Although it would receive a subsidy from tax provisions, the tax subsidy would not be sufficient to offset the royalty that would be collected under the Alberta, British Columbia, or Alaska regimes.

Under the Norway tax system, the development would not receive any subsidy. However, the Norway regime takes very little from this development. It is the second most favourable to industry.

6.3.8 Upper Keg River 45

Exhibit 16 provides the amount of economic rent taken by the government and industry and Table 11, *following*, presents the data in table form.

Exhibit 16

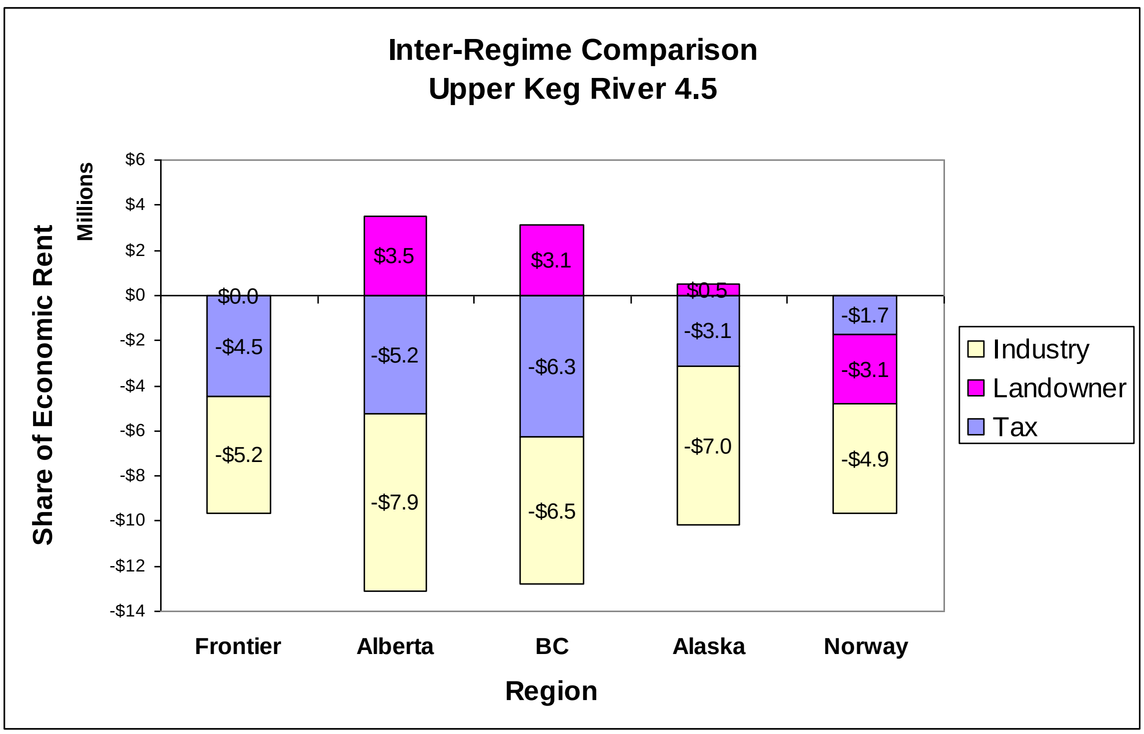


Table 11

Region / Prospects	Share of Economic Rent ($ Millions)				
	Frontier Lands	**Alberta**	**B.C.**	**Alaska**	**Norway**
Industry	-$5.16	-$7.89	-$6.49	-$7.03	-$4.87
Land Owner	$0.00	$3.49	$3.13	$0.53	-$3.06
Tax	-$4.48	-$5.24	-$6.28	-$3.14	-$1.71

The Upper Keg River prospect would not proceed at $4.50/mcf because it provides negative return to industry. The available economic rent is negative $10 million.

If the development did proceed, it would pay no royalty under the Frontier Lands regime. Some of the loss would be offset by tax reductions.

Under the Alberta, British Columbia, and Alaska regime, the development would pay royalty, but would benefit from tax reductions.

Under the Norwegian regime, both landowner and tax shares are negative. Industry's total loss under the Norwegian regime would be less than the loss under the Canadian regime.

6.4 Summary of Results

Exhibit 17, *following*, shows the government percentage share of economic rent taken for the six cases where the economic rent was positive. We show this as a line graph in order to highlight the trends that appear as the amount of available economic rent decreases. Table 13, *following*, provides the total take of the government.

The share of rent taken by the government is in the range of 60% to 80% for every regime for the first four cases. The Frontier Lands regime falls out of this range for the last two cases.

Also noteworthy is that the regimes that rely on ad valorem royalty formulas (Alberta, British Columbia, and Alaska) take a higher share of rent at the $4.50/mcf price than they do at the higher price. Also these regimes take more from the Colville prospect than from the Beaver River prospect because in the Colville prospect, the costs are a higher percentage of revenue.

Exhibit 17

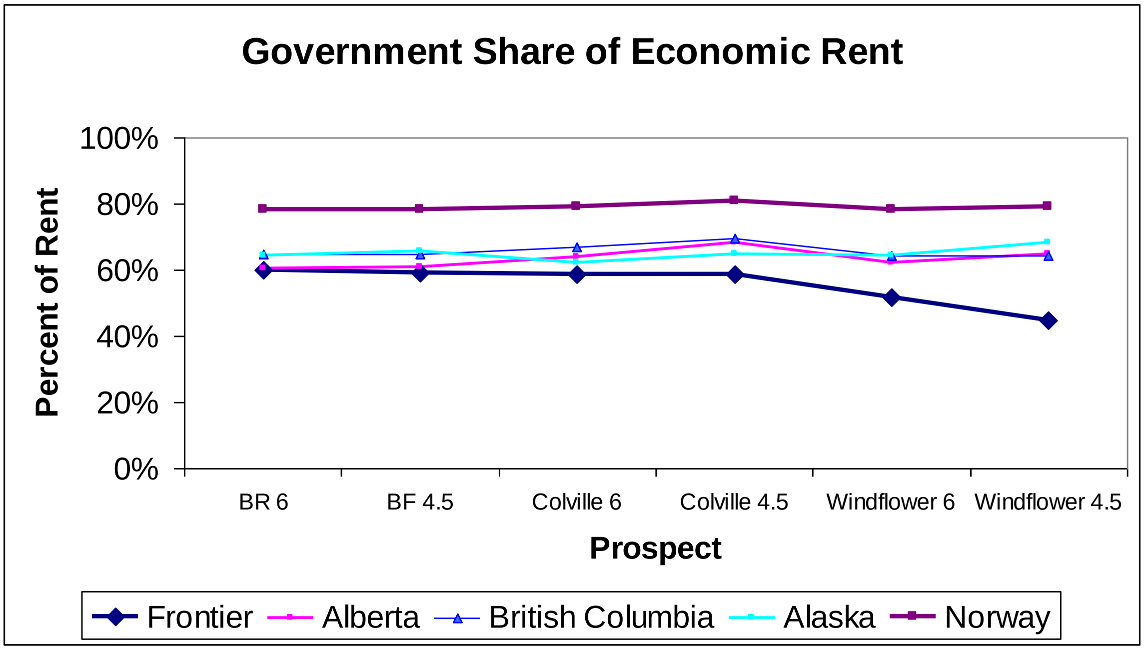


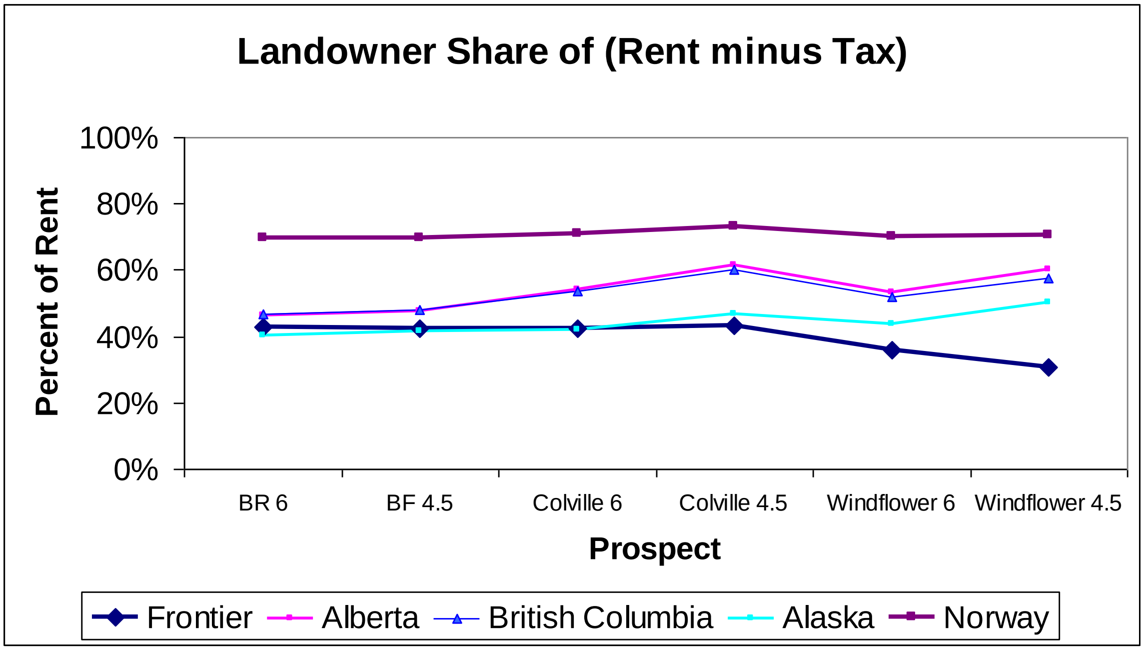
Table 13

Prospects	Government Share of Economic Rent					
	BR 6	**BF 4.5**	**Colville 6**	**Colville 4.5**	**Windflower 6**	**Windflower 4.5**
Frontier Lands	60%	59%	59%	58%	52%	45%
Alberta	60%	61%	64%	68%	62%	65%
B.C.	65%	65%	67%	70%	64%	65%
Alaska	65%	65%	62%	65%	65%	68%
Norway	78%	78%	79%	81%	78%	79%

As the available economic rent decreases toward zero, the Frontier Lands regime would take a smaller and smaller share of economic rent. Somewhere between a prospect like Windflower 4.5 and an uneconomic prospect like Upper Keg River 6, the Frontier Lands regime starts providing a tax subsidy. The tax subsidy also appears for Alberta and British Columbia, but is offset by increasing royalty.

Exhibit 18 is similar to Exhibit 17, except that we have excluded tax from the economic rent and show how the rent minus the tax is split between the landowner and the developer. This presentation highlights the effect of just the royalty differences.

Exhibit 18



Under this comparison, the competitive position of Alaska is improved. This is because Alaska has the highest corporate tax rate and also has a severance tax.

The trend for Alberta, British Columbia, and Alaska to take a higher share of rent from less economic prospects is more pronounced for royalty than for the combined effects of royalty and tax. This is because tax reductions offset some of the royalty increase.

As the available economic rent decreases toward zero, the Frontier Lands royalty regime would take a smaller and smaller share of economic rent. The royalty does not go to zero on any prospect with positive economic rent, but it becomes low enough so that royalty is less than the value of a tax benefit that appears in the Canadian corporate tax system.

In contrast, the marginal behavior of the royalty regimes of Alberta, British Columbia, and Alaska is to take an increasing percentage of the available rent. Before the economic rent available becomes zero, the royalty formulas would start taking more than 100% of the economic rent. In order to develop marginal prospects, these jurisdictions must introduce special programs (For example, Alberta has a deep gas holiday and a tax credit program; British Columbia has a coalbed methane program and a deep gas holiday; Alaska has reduced royalty on remaining prospects in Cook Inlet.) The effect of these special programs is to lower the percentage taken as rent on the affected marginal prospects.

7.0 Review of Pembina Report

The Pembina Institute conducted a study dealing with the hydrocarbon sector and presented its analysis and findings in 2004 in a report entitled, "When the Government is the Landlord," herein referred to as the "Report." The objectives of the study were to:

1. Evaluate the degree to which governments in western and northern Canada capture economic rent from oil and gas development in comparison with rent capture in Alaska and Norway;

2. Consider the need for and importance of non-renewable permanent funds, present evidence of the magnitude of such funds in Alaska and Norway, and compare the situation in these jurisdictions to Alberta's Heritage Fund; and

3. Investigate trends in environmental impact associated with oil and gas development and highlight the significance of such trends in light of increasing oil and gas development pressures in western and northern Canada.

As this study deals with the comparative analysis of fiscal regimes, our review of the Report will be restricted to the Objective #1, above.

The Report reviews the rent collection in Alberta, British Columbia, Saskatchewan, Northwest Territories, Yukon, Alaska and Norway for the years 1995-2002. These jurisdictions were selected because the Report builds and extends the 1999 study done by the Parkland Institute, which compared the revenues collected by the governments of these jurisdictions from oil and gas production.

The Report criticizes the Parkland study for its weakness in its approach, therefore, the usefulness of its conclusions. It states, "… the study (Parkland) did not explicitly measure the differences in the amount of rent available in each of the jurisdictions … . Higher revenue generation does not necessarily imply higher economic rent. Indeed, higher revenue generation may be explained by either lower production costs or a higher resource value. Without analyzing differences in costs and the value of oil and gas resources, it is not possible to say whether more or less rent was actually captured in a region."

In this section, we briefly outline the methodology and the conclusions of the Report, then we provide our assessment.

7.1 Methodology

In order to establish the economic rent captured in each of the regions, it establishes oil and gas revenues, oil and gas production costs and the value of oil and gas resources using aggregate data from public accounts and industry associations. For example, it took for a year the total revenues collected by government and total yearly expenditures of exploration, development and production. All data is converted to Year 2000 dollars using the Consumer Price Index. The difference between total revenues and total costs is shown as the available economic rent. The revenues taken by a government is established as a proportion of the available rent. All analysis is done in 2000 $/BOE (barrels of oil equivalent).

Table 14 represents Table 4-8 the Pembina Report (presented below) shows the portion of rent captured by governments during the period 1995-2002.

Table 14—Rent Captured by Governments

	% of Rent Captured							
Region	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**
British Columbia	100	100	100	100	100	47	100	100
Alberta	89	100	100	100	35	31	58	41
Saskatchewan	50	51	100	100	58	23	50	75
Yukon Territories	13	40	100	100	8	91	100	100
Northwest Territories	13	40	100	100	9	91	100	100
Alaska	100	100	100	100	100	100	88	100
Norway	64	80	96	100	100	65	100	100

Table 15 shows the average percent of rent captured in each jurisdiction over the entire time period. These are show in figure 4.8 of the Report, and as figure 2 of the Report's Executive Summary. (These percentages can be compared to the percentages in our Table 13 – Government Share of Economic Rent).

Table 15—Average Rent Captured

Region	Average % of Rent Captured
British Columbia	93
Alberta	69
Saskatchewan	63
Yukon Territories	69
Northwest Territories	69
Alaska	99
Norway	88

7.2 Conclusions

The following is a summary of the Report's conclusions:

- Alaska and Norway collected higher revenues from oil and gas production than Canadian jurisdictions.

- With the exception of British Columbia, all other Canadian regions, Alberta, Saskatchewan, Yukon Territory and the Northwest Territories did not capture as much available economic rent as Alaska and Norway.

- Governments in Alaska and Norway have implemented policies that allow them to capture a greater portion of the economic rent. These are:

  - Norway:

    - Special tax from oil and gas @ 50%.

    - Ownership of oil and gas operations allows it to collect dividends.

  - Alaska:

    - Production tax.

7.3 Assessment

The Report is well presented and may appear convincing to some readers. However, an in-depth review of the Report shows that the Report's conclusions are based on superficial analysis and a flawed approach. Therefore, it does not offer a basis for meaningful policy review for the Canadian jurisdictions.

Following are the key weaknesses of the report:

7.3.1 Gap between presentation of concepts and analysis

The Report correctly outlines the concept of economic rent and states that for a comparative analysis to be meaningful, it must be based on economic rent. For example, the Report states, "… at the most detailed level, economic rent varies not by country or by company but rather by reservoir. Thus, for every reservoir in a region, a different amount of rent is available for capture by the local government. The amount of rent shifts with the price and supply (cost) of oil and gas."

However, the Report in fact does not measure economic rent. The Report essentially ignores reservoir characteristics and the large differences in the amount of rent available from different reservoirs.

The authors do not appear to comprehend that economic rent not only varies by reservoir but that in fact economic rent can only be measured at the level of a reservoir. The amount of rent available is a characteristic of the specific reservoir in much the same way that the amount of oil or gas available is a characteristic of the reservoir. Just as reservoirs in a jurisdiction have different sizes, they also have different amounts of economic rent available. The amount of economic rent does not depend on whether or not the reservoir is developed just as the amount of recoverable oil that exists does not depend on whether or not it is in fact recovered. The amount of recoverable oil may depend on technology and the amount of economic rent may depend on market conditions – but both are characteristic of the reservoir and must be measured at that level.

What the report presents is simply aggregate annual revenue and aggregate annual costs. The report contends that the difference between these two numbers is somehow related to economic rent available in that year. But this is comparing apples to oranges. Revenue in any one year is affected by historical development decisions and current prices. Costs in any one year are greatly affected by expectations regarding the future. Annual aggregate differences between revenue and cost simply measure annual income or cash flow.

Moreover, annual income or cash flow is greatly affected by the "maturity" of a basin. Annual aggregate cash flow in an immature" (unexplored) basin will normally be negative—there are lots of exploration expenditures, but little production and therefore little revenue. In contrast a mature basin will have lots of revenue from existing developments, but may have little exploration.

The authors of the Report encountered years where industry expenditures in some basins exceeded their revenues. The authors ignored this negative value. They presented the economic rent available for those years as zero. However a high level of industry exploration expenditures does not mean that there is no economic rent available—it means exactly the opposite. Industry makes high exploration expenditures at a particular time in a particular basin because industry thinks that there is lots of economic rent available.

The Report has the same weakness that it pointed out in the Parkland Study. It does not measure economic rent. Simply subtracting annual cost numbers from annual revenue numbers does not amount to measuring economic rent or account for the difference in the quality of the resource. To measure economic rent one must consider the nature of the reservoirs and the range of differences. This means considering reservoir size, drilling success rates, flow rates, depletion rates, lags between exploration and development, and a host of other variables.

It is of course possible to use historical cost and revenue data to estimate economic rent. However, data must be considered in the context of a specific reservoir. It is also possible to produce aggregate data for a basin. However, before historical reservoir data can be aggregated, one must adjust the data for year of discovery and shift the reservoir level data so that the cash flow relating to each reservoir is aligned at the same starting date.

7.3.2 Incorrect representation

The key finding of the Report, shown previously in Table 14, is not mathematically correct. It is derived from two other tables of the Report, Table 4-2 and 4-7, presented below.

Table 4-2 of the Report: International Comparison of Revenues from Oil and Gas Production (2000$/BOE)

Region	Revenues							
	1995	1996	1997	1998	1999	2000	2001	2002
British Columbia	2.6	3.7	3.7	2.7	4.1	8.6	10.1	8.1
Alberta	3.1	3.2	3.1	3.1	2.1	4.2	8.5	6.8
Saskatchewan	4.5	4.4	4.7	3.5	2.7	5.0	6.6	5.9
Yukon Territories	1.2	2.7	1.8	1.6	1.1	2.2	4.9	4.5
Northwest Territories	1.2	2.6	1.7	1.2	1.3	2.2	2.5	4.5
Alaska	13.3	10.5	12.2	10.5	8.7	13.7	13.0	10.5
Norway	7.9	12.8	14.8	6.8	6.7	19.7	26.1	18.1

The Reports states that “Table 4-8 shows government revenues (Table 4-2) as a percentage of rent available (Table 4.7)” If one does the percentage calculations stated, the result is Table 16, *following*.

Table 4-7 of the Report: Economic Rent Available By Region (2000$/BOE)

	Revenues							
Region	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**
British Columbia	0.8	0.0	0.0	0.0	3.7	18.1	8.7	4.8
Alberta	3.5	1.6	0.0	0.0	6.1	13.4	14.8	16.5
Saskatchewan	9.0	8.6	4.5	1.8	4.6	21.5	13.1	7.9
Yukon Territories	9.1	6.8	0.0	0.0	14.5	2.4	0.0	0.0
Northwest Territories	8.8	6.5	0.0	0.0	14.4	2.0	0.0	0.0
Alaska	0.9	0.0	12.0	3.4	0.0	8.0	14.7	0.0
Norway	12.4	15.9	15.4	0.0	0.0	30.1	23.4	0.0

Table 16
Portion of rent captured by government, per BOE (Table 4-2 as percent of Table 4-7 of the Report)

	Year							
	1995	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**
British Columbia	294%	-310%	-82%	-99%	116%	47%	116%	176%
Alberta	90%	201%	-81%	-1,552%	35%	31%	58%	41%
Saskatchewan	50%	51%	106%	183%	57%	23%	50%	75%
Yukon	12%	36%	-3%	-1%	24%	81%	-6%	-2%
Northwest Territories	14%	39%	-4%	-1%	9%	90%	-3%	-2%
Alaska	1,555%	-717%	104%	329%	-322%	185%	99%	-291%
Norway	64%	81%	95%	-75%	-20%	66%	112%	-22%

The table 14, as presented as table 4.8 in the Report, replaces all of the negative values in the above table 16 with 100% and also replaces all values above 100% with the value 100%. Instead of explaining why their methodology resulted in the government taking more than 100% in some cases and negative economic rent in others, the authors simply removed the offending unexplainable values.

The actual explanation shows up most clearly if we look more closely at Table 4.7 of the Report. This table shows zero economic rent available in several cases. These values should in fact not be zero, but negative numbers. Table 4.7 was stated to be the difference between revenue and costs. (Table 4.4 minus Table 4.5) However, in some years, revenue was less than cost. This results in negative numbers for those years. Table 16, *following*, is the “corrected” Table 4.7, including the negative numbers, as follows:

Table 16
Corrected Table 4.7 of the Report (Table 4.7—Economic rent available per BOE (Table 4.4 minus Table 4.5))

	Year							
	1995	1996	1997	1998	1999	2000	2001	2002
British Columbia	0.9	-1.2	-4.5	-2.7	3.5	18.1	8.7	4.6
Alberta	3.5	1.6	-3.9	-0.2	6.1	13.4	14.8	16.5
Saskatchewan	9.0	8.6	4.5	1.9	4.7	21.4	13.1	7.9
Yukon	9.1	6.8	-50.9	-120.6	4.5	2.4	-82.5	-286.8
Northwest Territories	8.8	6.5	-50.2	-120.1	14.5	2.4	-82.9	-281.6
Alaska	0.9	-1.5	12.0	3.4	-3.1	8.0	14.7	-4.3
Norway	12.4	15.8	15.5	-9.1	-32.8	30.0	23.3	-81.9

The large negative numbers for the Yukon and the Northwest Territories appear in 1997, 1998, 2001, and 2002. In these years industry made significant exploration expenditures but received only a small amount of revenue from existing discoveries. It is very typical for an immature basin to show exploration expenditures significantly higher than revenue. The actual revenue that industry expects to get from those exploration expenditures are in the future. Comparing current costs to current revenue says very little about the amount of economic rent that is actually available.

The cases shown in Table 16 (the corrected Table 4.8 of the Report) where the government share of economic rent goes above 100% occur for a similar reason. In these years, costs in the form of exploration expenditures were high, but not quite as high as revenue, so there is still a positive income or cash flow. However, net income is less than the total amount collected by government. Hence dividing normal government number take by this small cash flow number leads to percentages above 100%.

7.3.3 Narrow focus

If the Report covered a large enough period of time, and produced just the average ratio of government revenue to industry cash flow, and if the government fiscal regime did not introduce any inefficiencies, then this ratio would eventually start approaching the average government take as a percent of economic rent available. However it would say little about the efficiency or effectiveness of the fiscal regime. The Report is focused on revenues collected by various governments instead of assessing the robustness of fiscal regimes in capturing the available economic rent and the efficacy of government policies for rent collection.

7.3.4 Choice of jurisdiction

The choice of jurisdictions for the comparative analysis of fiscal regimes appears to be arbitrary. Generally, jurisdictions which would directly compete for private investment are included. Factors considered in the selection of jurisdictions for comparison include proximity, similarity of geological and physical characteristics, the nature of the resource, and the stage of resource development.

The comparison of Frontier Lands (NWT) with Norway is not meaningful. Norway is mostly developing offshore oil, has extensive infrastructure, is dominated by a nationalized oil company, and has a national policy that development be slow and steady. Norway may be comparable to proposed offshore developments, but not to any existing development in the NWT.

The comparison of NWT with Alaska may be justified on the basis of proximity and similarity of physical conditions; however, there is significant difference in the stage of resource development. Alaska has decades of history of production whereas the NWT is at the initial stages of resource development.

Comparison with Alberta and British Columbia is meaningful in the context of the similarities between the northern portions of Alberta and British Columbia and the southern NWT. However, most of Alberta and British Columbia developments have been in areas that are much different from the northern developments. A meaningful comparison could be made if just the northern parts of British Columbia and Alberta are considered.

Saskatchewan has a very different situation from any of the other areas considered. It also is very small in terms of remaining undiscovered gas.

7.3.5 Other weaknesses

Following are examples of other weaknesses in the report:

- ♦ Although the report made mention of the need to include a normal rate of return, they give no indication of what rate of return they are using. Nor did they appear to have in fact used any such rate. Their adjustment to current year dollars used just the CPI (see page 5). The rate of return should have been included along with inflation when they collapsed annual values to Year 2000 dollars.

- The conversion factor used for transforming gas to barrel of oil equivalent given on page 5 is not correct. The factor given is the factor for converting a cubic meter of oil to a barrel of oil. However, the authors appear to have used CAPP and Norway numbers that are expressed in barrels of oil equivalent, and did not use their stated conversion factor.

- The explanation on page 11 regarding why Alberta employs more people per barrel than Norway is not correct. More correct would be to note that Alberta has a hundred times as many wells, in spite of having lower total production.

8.0 Conclusions

Following is a summary of the conclusions we draw:

1. The Frontier Lands regime is most favourable to industry of the regimes considered. In each of the viable prospects considered, the Frontier Lands regime left industry with a higher share of the available economic rent. The difference is small for the most profitable BR-6 prospect, but becomes significant for less economic prospects.

2. The Frontier Lands regime and the Norwegian regime are more responsive to price than the regimes of Alberta, British Columbia, and Alaska. For the prospects considered, the Alberta, British Columbia and Alaska regimes showed a negative response to price—they took a higher share of available rent at the lower price than at the higher price.

3. Alberta and British Columbia have price sensitivity features build into their royalty formulas. However, current price levels are beyond the range of prices anticipated by these formulas.

4. The Frontier Lands regime will not prevent a development from occurring if the development is fundamentally economic. It will in fact allow a development to proceed that is slightly uneconomic.

5. For the most profitable developments, the Norwegian regime captured substantially more of the economic rent than the other regimes.

6. For Alberta, British Columbia, and Alaska, the royalty systems tend to take an increasing share of economic rent as the amount of available economic rent decreases. This is opposite the trend for the tax systems in these jurisdictions.

7. In order to attract developers to marginal prospects, Alberta, British Columbia, and Alaska have introduced a number of special programs that reduce royalty in certain areas or for certain types of development. We did not examine the impacts of these special programs. Special provisions for coalbed methane, deep gas, Cook Inlet, etc. attract some capital to some marginal developments. However such special programs have administrative costs and may introduce other distortions.

8. Generic royalty fitting all types of plays onshore and offshore may not be optimal for all specific circumstances. However, the creation of multiple

royalty regimes to address variation between prospects can lead to increasing complexity and administrative overhead.

9. The Frontier Lands regime and the Norway regime both take a share of economic that is generally in the acceptable range of 60% to 80% of available rent. However, the Frontier Lands regime is at the bottom of this range and the Norway regime is at the top. The difference is mostly due to the Canada land regime's post-payout rate of 30% of net income from operations being significantly lower than Norway's rate of 50% on net income from operations.

10. The Frontier Lands regime and the Norway regime differ significantly in how the regimes treat industry's cost of capital. The Frontier Lands regime provides the risk free interest rate plus 10%. Norway provides actual interest expense.

11. The Frontier Lands regime's allowance for industry's cost of capital is significantly higher than industry's actual cost of capital, which this analysis estimated as the risk free interest rate plus 3%.

12. Norway's method of accepting actual interest expense automatically adjusts for changes in the financial markets but does not provide for industry's use of equity capital. Norway's cost uplift provisions provide some recognition of industry's use of equity capital, but are not generally transferable to prospects that are not typical of Norway's offshore developments.

13. The Canadian tax provision of immediate write-off of explorations costs plus acceptance of interest expense provides a significant benefit to industry for corporations that have a high debt to equity ratio.

14. The Pembina Report, reviewed in Section 7 of this report, has a major flaw in that it measures annual cash flow instead of available economic rent. The comparisons between jurisdictions in that report therefore have little meaning or validity.

15. The Pembina report also presented the government share as 100% where the actual calculated percentage was above 100% or negative. This presentation obscured the fact that their methodology was not measuring economic rent.

APPENDIX 1

Resource Background

Appendix 1.1—Potential in Northern Canada

Many petroleum basins in the world have long histories of exploration and production, and may be described as mature. Many such basins, for example, the Western Sedimentary Basin, are entering long term declines in production as new discoveries fail to make up the depletion of producing fields. In contrast, the federal lands in the Northwest Territories, Nunavut and in the northern offshore (Frontier Lands) can be described as "immature." Although there have been significant discoveries, most of the ultimate potential has yet to be discovered.

To understand the challenges facing development in Canada's north, it is useful to divide the area into four regions[6]. These are (1) the southern territories, (2) the northern plains, (3) the Mackenzie Delta and western offshore, and (4) the eastern offshore.

The southern territories and the northern plains are part of the northern extension of the Western Canadian Sedimentary Basin (WCSB). The Northwest Territories portion of the WCSB is expected to contain 15 trillion cubic feet of natural gas[7]. Less than 10% of the ultimate potential has been discovered.

Existing developments in the southern territories are concentrated in the Cameron Hills area that overlaps the border between Alberta and the Northwest Territories and in the Liard Plateau that overlaps the border between British Columbia, the Yukon and the Northwest Territories. The Cameron Hills area offers the typical Western Canadian Sedimentary Basin mix of shallow and medium depth targets from the Pleistocene, Cretaceous, and Middle Devonian strata. The Liard Plateau offers medium to deep targets similar to those in the Alberta foothills where successive mountain building events produced significant hydrocarbon accumulations in Mississippian and Devonian strata. The southern territories have significant potential for gas, but only modest potential for oil. The western portion of this area has pipeline connections and currently markets hydrocarbon worth about half a billion dollars per year[8]. There are discoveries in the Great Slave Plain as far east as Hay River. However, the eastern areas are not connected to the pipeline grid.

The companies that are interested in the resources of the southern territories are generally the companies that have explored and developed northern Alberta and British Columbia.

[6] NEB and GSC publications usually split these regions further.
[7] *All Reserve Estimates are from the National Energy Board, unless otherwise noted.*
[8] *CAPP 2003 Total Industry Revenue for Yukon, NWT, and Nunavut*

The specialized knowledge of local geology and operations gives these companies an advantage in the similar adjacent areas. These companies are also familiar with Alberta and British Columbia fiscal regimes, regulations, and approaches to environmental issues. The fact that the southern territories have seen much less exploration than the adjacent areas of Alberta and British Columbia is only partly due to geology and lack of infrastructure. Unresolved native land claims led to suspension of exploration activity until the native issues could be resolved.

The northern plains include the Mackenzie Plain, the Peel Plateau, and Colville Hills. The Mackenzie Plain includes the Norman Wells oil field. This field has produced over 200 million barrels of oil since it started production in 1920. It produced 8 million barrels in 2003. The oil potential in the northern plains area makes the area attractive for exploration even far from areas that are connected to the North American gas pipeline grid. In addition to over 300 development wells at Norman Wells, there have been 76 exploratory wells in the Mackenzie Plain, 52 in the Peel Plateau, and 22 in the Colville Hills. Although some wells have been technically successful, most have been plugged as dry holes because the flow rates were too low.

The Mackenzie Delta and the western offshore contain very thick hydrocarbon bearing strata that makes the area prospective for mega-fields. In the area that is now the Inuvialuit Settlement Area, there were 239 wells drilled prior to 1991, of which 83 were offshore. These wells located 13 tcf of natural gas. Ultimate potential is currently expected to be about 65 tcf. The gas resource has been developed only for local use at the town of Inuvik.

The mainland eastern arctic in Nunavut is exposed Pre-Cambrian Shield that is not prospective for hydrocarbons. The eastern offshore area does have potential. Reserves of over 600 million barrels of oil and 12 trillion cubic feet of natural gas have been proven by drilling 160 wells. All but 10 of the wells are in the Sverdrup Basin, some 800 kilometers north of Cambridge Bay. Although ultimate potential may be over 60 tcf of gas, the remote and difficult conditions make the area less attractive than the Newfoundland offshore area to the south and the Norwegian continental shelf to the east. Canadian Natural Resources Ltd. is the only company with a current exploration license in the area.

Appendix 1.2—Potential in Comparison Areas

1.2.1 Alberta and British Columbia

The Western Canadian Sedimentary Basin (WCSB) covers most of Alberta. The northern edge of WCSB extends into northeast British Columbia, the Yukon, and the Northwest Territories. Hence the geology of most of Alberta and of the most prospective area of British Columbia is similar to the geology of the southern territories. However, there are major differences in the extent to which the areas have been developed.

There have been over 200,000 wells drilled in Alberta. These wells have discovered 60 billion barrels of oil and 115 trillion cubic feet of natural gas. Estimates of ultimate potential suggest that about 90% of oil and 60% of natural gas deposits in Alberta have been discovered. Remaining discoveries are expected to be in smaller pools and in pools with less desirable production characteristics. The average initial production rate for recent Alberta gas discoveries has declined to about 300 mcf per day.

There have been over 14,000 wells drilled in the British Columbia portion of the WCSB. The wells have discovered perhaps 30% of expected potential of 50 trillion cubic feet of natural gas. Four other small and lightly explored basins in the interior of British Columbia are expected to contain in total about 15 tcf of gas.

1.2.2 Alaska

Alaska has a complex geology arising from lands being accreted to the North American continent at different times and from different directions. Hydrocarbon potential exists in several distinct basins. All historical production and discovered reserves are onshore. Conditions in the prospective areas of Alaska are similar to conditions in the Canadian Beaufort Sea and Mackenzie Delta. These are arctic working conditions, gas-prone targets, and lack of infrastructure. Both the Alaskan and Canadian areas have unexplored regions where large discoveries are possible.

There have been 15 billion barrels of oil[9] produced in Alaska. Remaining proven oil reserves total 7 billion barrels. There are an additional 10 billion barrels of probable oil in the Naval Petroleum Reserve and another 10 billion barrels of probable oil in the Alaskan National Wildlife Refuge. The ultimate potential for oil is not much larger than the produces and proven reserves plus estimates for the two restricted areas.

There have been 7 trillion cubic feet of gas produced. Remaining proven gas reserves total 36 trillion cubic feet. There is significant ultimate potential for gas. Estimates prepared to support the Alaskan Gas Pipeline proposal show ultimate

[9] *Alaska estimates are from a speech given February 19,2004 by Mark Myer, the Director of Alaska Department of Natural Resources. Presentation posted at the Department web site. The undiscovered potential estimates are not directly comparable to Canadian estimates.*

potential for technically recoverable conventional gas of 230 trillion cubic feet, of which 186 is undiscovered.

1.2.3 Norway

Norway is the world's sixth largest producer of oil, following Saudi Arabia, the U.S., Russia, Iran, and Mexico[10]. Norway is the world's third largest exporter of oil, following only Saudi Arabia and Russia. Norway produces about 3.25 million barrels of oil per day, and exports 3 million barrels. Norway's oil production is about the same as Canada's 3 million barrels per day. Canada is just self sufficient in crude oil, exporting just over 1 million barrels per day and importing just under 1 million barrels. (Canada is a significant net exporter of refined oil.)

Norway produces 2.5 tcf of gas per year, and exports 2.4 tcf. Norway is the world's sixth largest producer of gas, following Russia, U.S., Canada, U.K., and Netherlands. Norway's gas production is increasing, so that Norway is expected to surpass U.K. and Netherlands by 2006. Norway is the world's third largest gas exporter, following only Russia and Canada. Norway produces about one-third as much gas as Canada and exports about half as much. Norway produces one tenth as much gas as Russia. Although important to Europe, Norway is very minor compared to Russia. Norway's proven gas reserves are less than 1% of the proven reserves in Russia.

Norwegian petroleum resources are all offshore. Individual wells are some of the most expensive in the world. However, they are also some of the most successful. The just over 1000 exploration wells drilled since 1966 had a 40% success rate and found 80 billion barrels of oil equivalent. (Abbreviated as boe. We use boe because Norway does not generally produce independent estimates for oil and gas.)

The Norwegian Petroleum Directorate divides the Norwegian continental shelf into three petroleum provinces. From south to north, these are the North Sea, the Norwegian Sea, and the Barents Sea.

The North Sea is most mature, with cumulative production of 20 billion boe, proven reserves of 60 billion boe, and undiscovered potential of 7.5 billion boe. The undiscovered potential is expected to be 4.4 billion barrels oil and 17.6 tcf gas.

[10] *International Data is from the U.S. Energy Information Agency. Norwegian data is from the Norwegian Petroleum Directorate.*

The Norwegian Sea is more gas prone. The estimated 7.7 billion boe of undiscovered resource is expected to be two-thirds gas.

The undiscovered potential in the Barents Sea is expected to be all gas. The estimate is 39 tcf.

Exploration and most development in Norway is done by the state oil company, Statoil. Private sector oil companies are involved as contractors and as investors. Norway's licensing system for new areas invites work bids from interested parties. Statoil then decides what work it will contract directly, and what will be part of a joint venture. Statoil was listed on the New York Stock Exchange in 2001. The government's direct ownership of Statoil is currently 82%. Statoil has also acquired interests in various petroleum ventures in 28 countries.

A second state company, Norsk Hydro, operates some fields. The government's direct ownership of Norsk Hydro is 49%. A 100% government-owned company, Gassro, manages the export pipeline system. Another 100% government-owned company, Gassled manages all trunk pipelines and gathering systems. The government also created a pure financial company, Petoro, to manage the State Directed Financial Interest.

The direct government development of the petroleum resources of Norway is managed to achieve a steady and orderly development. The government intentionally delays development of some discoveries. Norway's activities in the gas prone arctic are intended to defend its ownership rights in the offshore.

APPENDIX 2

Details of Royalty Formulas

Appendix 2.1—Frontier Lands

Royalty Rate on the 15 Special Leases

For the 15 specific leases listed in section 114-4 of the Canadian Petroleum Resources Act, the rates are as described in the Canadian Oil and Gas Lands Regulation; CRC C1518; under the Territorial Lands Act (R.S. 1985-c.70). The text of this regulation is at http://www.canlii.org/ca/regu/crc1518/sec85.html Section 85 prescribes an ad valorem royalty of 5% for the first three years and 10% thereafter.

Royalty Holiday

Royalty is reduced by the amount of the royalty investment credit calculated as:

> “investment royalty credit" of an interest holder means twenty-five per cent of that portion of the qualified frontier exploration expenses claimed by the interest holder as Canadian exploration expenses under the *Income Tax Act*, as amended from time to time, and certified by the Minister pursuant to subsection 10(3); (*crédit de redevance à l'investissement*)

These are costs for the exploratory well, excluding overhead costs and costs for which a specific incentive or reimbursement has been paid. The effect is to provide a royalty holiday equal in value to 25% of the cost of the exploratory well. (Reference SOR 92-26, Section 3.1.c.) There is no ring fence for this credit—any exploratory well anywhere on Canadian Lands will generate a credit that can be used on any lease. In particular, dry holes generate credits.

Return Allowances

The distinguishing feature of a resource rent royalty is that a return allowance is provided on the developer’s cumulative cash deficit. Unlike a net profits royalty, interest expense is not an allowed cost. The return allowance used in the payout calculation on Canadian Lands is equal to the long term government bond rate plus 10%, compounded monthly. The allowance is provided on the cumulative cash flow deficit. This deficit, defined as the “adjusted cumulative cost base” is equal to capital costs plus cumulative operating costs plus cumulative royalty, plus cumulative return allowance, plus cumulative net taxes, minus cumulative wellhead revenue. (Reference SOR 92-16, Section 9.)

In calculating the return allowance, capital costs incurred prior to project commencement are adjusted for inflation (Reference SOR 92-16, Section 9 (5)(a)). In calculating wellhead revenue, gross sales revenue is reduced by transportation costs, processing costs, and facility costs.

Facility costs are calculated using straight line depreciation (Form D-4, line 18), no interest expense, a financial return allowance equal to the government bond rate plus 5% (Form D-4 line 24, Form D-3 line 5), compounded annually applied to un-depreciated capital plus working capita, and a profit return allowance equal to 10% of operating costs (Form D-3, line 4).

Appendix 2.2—Alberta Royalty Formulas

Alberta formulas are sensitive to production rate and to price. They are constructed as a productive sensitive factor that is multiplied by a price sensitive factor. In the following, we describe the production sensitive factor first, then the price sensitive factor. We then present a graph that gives the rates at current prices at various levels of production.

Oil Royalty

Alberta classifies oil into three vintages and makes a distinction between heavy and non-heavy. The Oil royalty rate is determined by multiplying a basic production sensitive royalty by a price factor. Both the production sensitive royalty and the price factor use formulas that combine a straight-line portion with an asymptotic portion.

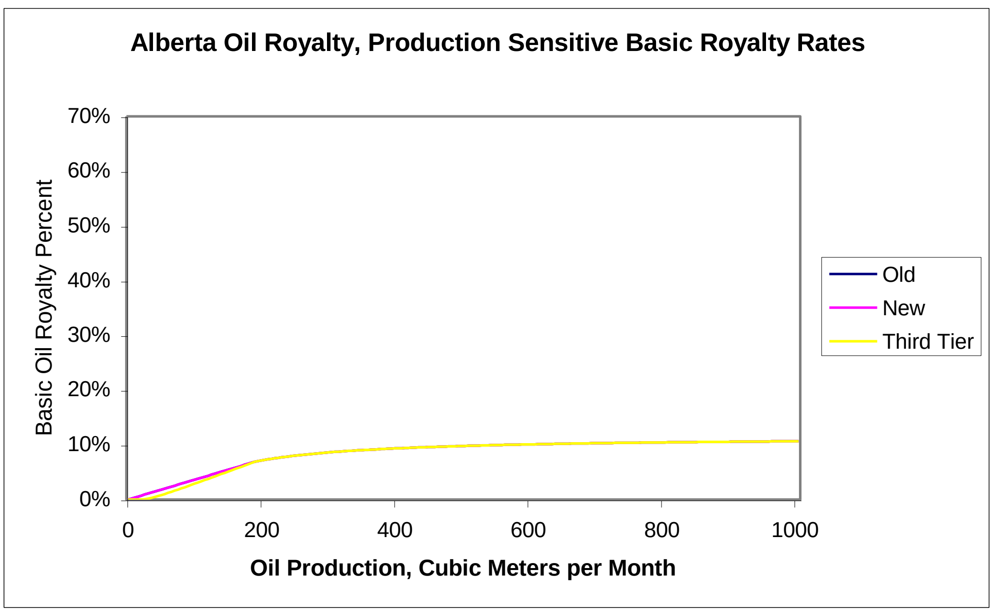


Chart A-1

- Old and New Basic rates are the same.
- All vintages are the same above a production rate of 190.7 cubic meters per month.

- Basic Royalty starts at zero for zero production.
- Rate increases in a straight line to 7% at a production rate of 190.7 cubic meters per month (190.7 cubic meters per month = 40 barrels oil per day).
- Rate then increases towards an asymptotic maximum of 11.5%.
- Third Tier does not start increasing until a rate of 20 cubic meters per month.
- Production sensitive formula makes no distinction between light and heavy oil.
- Formula, where V = Volume and R% = royalty percent, for Old and New:
    - R%=V/2755.04 if V<190.7, else
    - R%= [13.2+.115385(V-190.7)]/V

  for third tier,

    - R% = (V-20)^2/(2207.46*V) if V<190.7, else
    - R% = same formula as for old and new
- The Alberta Formula has odd parameters due to modification from earlier formulas.
- The 7% and 11.5% rates mentioned above are rounded from the actual values show below.

	Old and New	**Third Tier**
First Anchor Point for straight line.	(0, 0%)	(20, 0%)
Second Anchor Point for straight line.	(190.7, 6.9219%)	(190.7, 6.9219%)
Incremental Rate	11.5385%	11.5385%

Table A-2

- First Alberta sliding scale had R%= square root of production in barrels per day to maximum of 12.5%.
- The first straight-line plus asymptotic form had 15% at 40 bopd and maximum of 25%.
- Current form introduced in 1992 to mesh with desired royalty rates at the reference well.

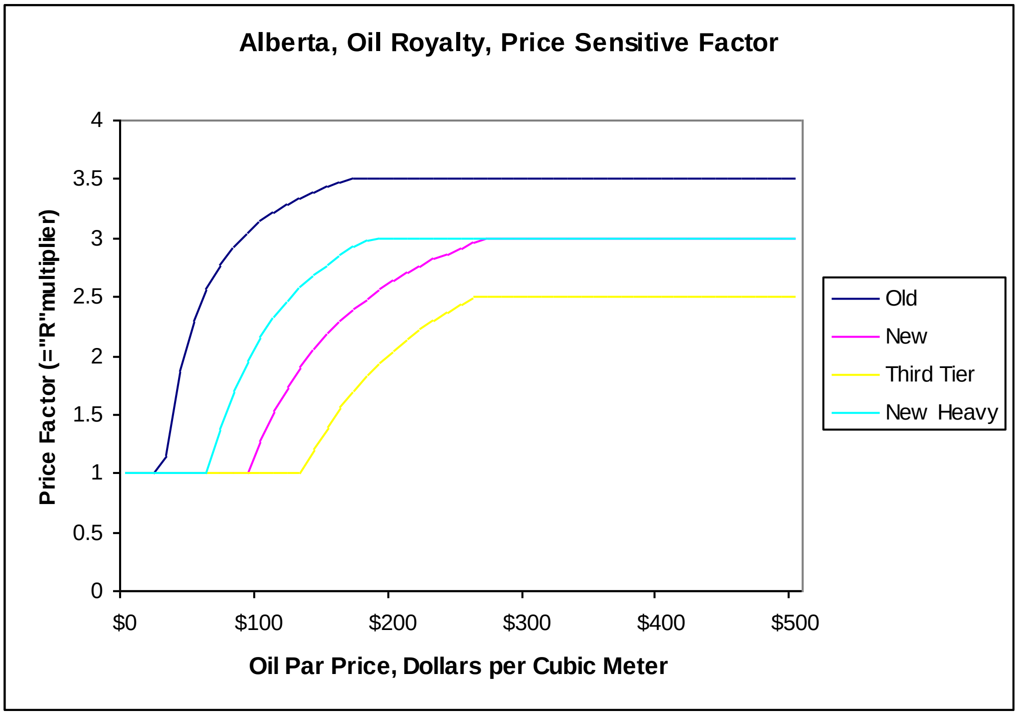


Chart A-3

- ♦ Price factors range from 1 to a maximum that depends on the vintage.
- ♦ Factor is 1 if the Select Price is Below the Par Price.
- ♦ Formula, where S= Select Price and P=Par Price.
  - Factor = S/P+4(S-P)/P
- ♦ The 2005 select prices, in Canadian Dollars per Cubic Meter, are:

	Old	New	Third Tier
Non-heavy	30.53	97.27	139.62
Heavy	30.53	65.61	139.62

Table A-4

- Price factors (called "R" multipliers) are published monthly along with the monthly par price. The R multipliers for March 2005 were:

	Old	New	Third Tier
Non-heavy	3.5	3	2.5
Heavy	3.5	2.97	1.81

Table A-5

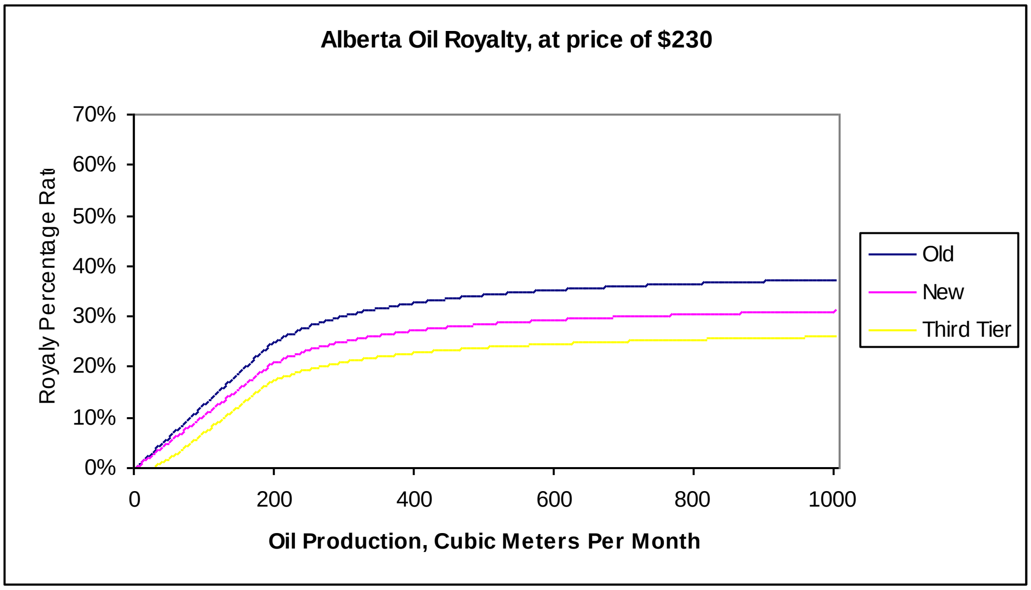


Chart A-6

- Oil Royalty is the Basic Production Sensitive Rate times a price factor.
- At the price of $230, the Price Factors are near their maximum values of 3.5, 3, and 2.5.
- At high rates of production, the royalty rates are asymptotic to 11.5% times the price factor. (Old, new, and third tier go to 40.4%, 34.6%, and 28.8%.)

Other Programs Affecting Alberta Oil Royalty

- Alberta Resource Tax Credit refunds 25% to 75% of royalty up to a maximum of $3 million per company. A property that is owned by an above limit company loses eligibility for ARTC if the property is transferred to a below limit company.
- Royalty on reactivated wells is reduced to zero for the first five years after the reactivation.
- Royalty is reduced on EOR projects. The reduction is calculated on a project specific basis. The reduction has the effect that the government pays a share of the incremental costs equal to its forecast share of the incremental production.
- Royalty on exploratory wells is reduced to zero for the first year of production.
- Royalty is reduced on wells with horizontal re-entry to the rate of the well before the reentry.
- AR 350/92, the Low Productivity Well Royalty Reduction Regulation, reduces royalty to 5% on wells that average less than 73 cubic meters of oil per month. (This reduction is not shown in the chart. It mainly affects wells that report on an annual basis. It would put a small kink at R%=5. The maximum impact is about $20 per affected well per month.)
- AR 65/92 reduces royalty to 5% for experimental projects.
- Oil sands projects have a completely separate royalty regime. The oil sands regime is the greater of a 1% Ad Valorem royalty or a post payout resource rent royalty of 25%. The return allowance used in payout calculations is the long term government bond rate plus 3%.

Gas Royalty

Alberta gas royalty uses two vintages (old and new). The royalty rate is sensitive to price and sensitive to rate of production in the low range. Starting in 2002, Alberta began applying the same price-sensitive formula independently to each component that can be separated by a gas processing facility.

Different prices for each component result in different royalty rates for each component. The royalty rate that applies to a stream of natural gas is the weighted average of the royalty rates on the components that are included in that stream. For example, if 70% of the energy value in a stream comes from methane and 30% from ethane, then the royalty rate on the stream will be the weighted average of the methane and ethane royalty rates. If the methane royalty rate is Rm% and the ethane royalty rate is Re%, then the royalty rate on the stream will be 70% Rm% plus 30%Re%.

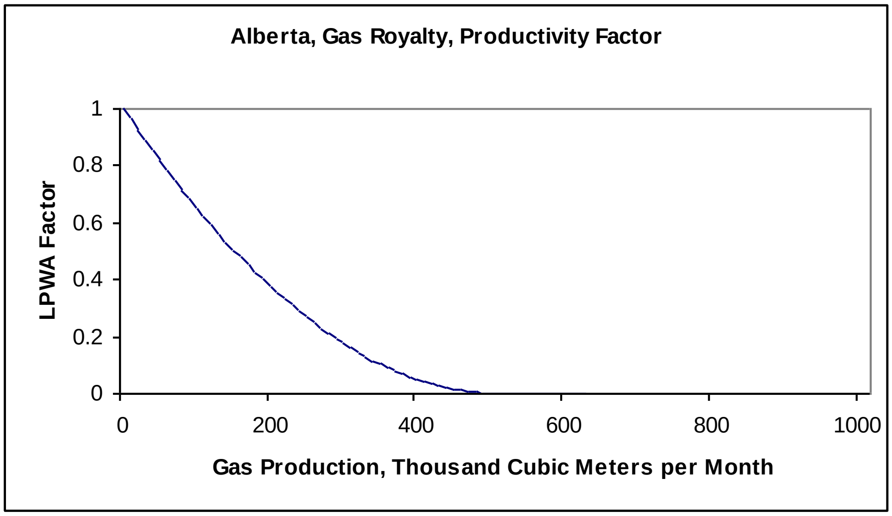


Chart A-7

- The productivity factor is used to reduce royalty on wells producing less than 16.9 thousand cubic meters per day.
- Productivity factor is multiplied by a royalty rate that is 5 points less than the rate set for methane.
- The resulting rate is then subtracted from the Price Sensitive Royalty Rate set for the well.

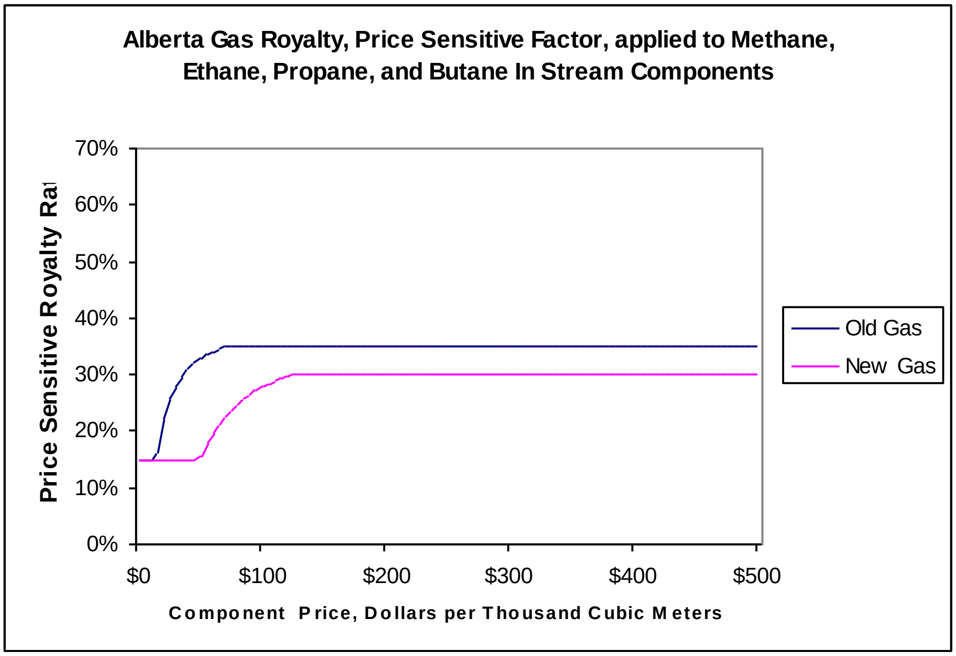


Chart A-8

- ♦ Below the select price, the rate is 15%.
- ♦ Rate then increases at a marginal rate of 40%.
- ♦ Rate is capped at 30% for new gas and 35% for old gas.
- ♦ Same formula and rates apply to methane, ethane, propane, and butane.
- ♦ Formula also applies to pentanes in stream, but pentanes liquid uses a different formula.
- ♦ Each component has its own monthly par price, therefore its own royalty rate.
- ♦ Formula is R%=.15(SP/PP)+ .40[(PP-SP)/PP], where
  - SP = Select Price for component.
  - PP = Par Price for component.
- ♦ The royalty percent is the weighted average of 15% and 40% where:
  - The weight given to 15% is the ratio of the Select Price to the Par Price.

- The weight given to 40% is one minus the weight given to 15%.

♦ For 2004, the select price is $1.333 per gJ for new methane, new ethane, propane, butane, and ISC pentane.

♦ The select price is $.392 for old methane and old ethane.

♦ The par prices for January 2004 were published March 15, 2004.

	Methane	Ethane	Propane	Butane	Pentane	Residue
as ISC, in $/gJ	6.06	6.38	6.48	6.52	6.54	6.10
as liquid, in $/M3			use ISC R%		283.55	

Table A-9

♦ Valuation of Propane and Butane sold as liquids use the liquids reference price. (Propane: $208.59; butane: $269.04.)

♦ Formula for pentanes is R%=.22(SP/PP)+MR[(PP-SP)]/PP, where MR=.35 for new and .50 for old. Select price for pentanes liquids is $47.65/m3.

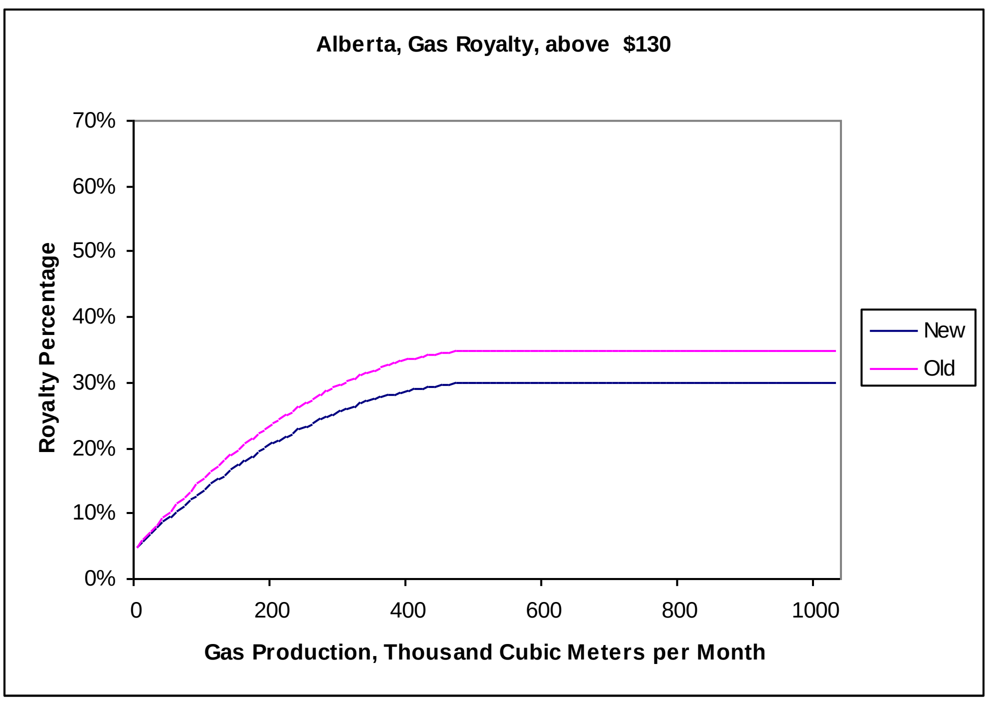


Chart A-10

- Minimum Rate is 5%.
- At current prices, methane, ethane, propane, and butane price-sensitive rates are all at their maximums of 35% for old methane and old ethane, and 30% for new methane, new ethane, propane, and butane. Therefore the graph reflects just production sensitivity.
- Each component increases to the price sensitive rate at production rate of 515 Thousand Cubic Meters per Month (=16.9 Daily Rate).
- Rate is not sensitive to production rate increases beyond the low productivity range.
- Rate for the well is the weighted average of the rates computed for each component produced.

Other Programs that Affect Alberta Gas Royalty

- Alberta Resource Tax Credit refunds 25% to 75% of royalty to eligible companies.
- Fifty percent of sulphur recovery costs allowed in cost allowance.
- Cogeneration projects produce royalty credits.
- Deep Gas Royalty Holiday.
- Experimental wells have royalty rate of 5%.

Appendix 2.3—B.C. Royalty Formulas

British Columbia formulas are sensitive to production rate and to price. They are constructed as a productive sensitive factor that is multiplied by a price sensitive factor. In the following, we describe the production sensitive factor first, then the price sensitive factor. We then present a graph that gives the rates at current prices at various levels of production.

Oil Royalty

British Columbia classifies oil using three vintage categories (old, new, and third tier) two drilling intent categories (exploratory, non-exploratory), and two oil quality categories (heavy, light). British Columbia oil royalty is production-sensitive, but is sensitive to price only for third tier oil and heavy oil.

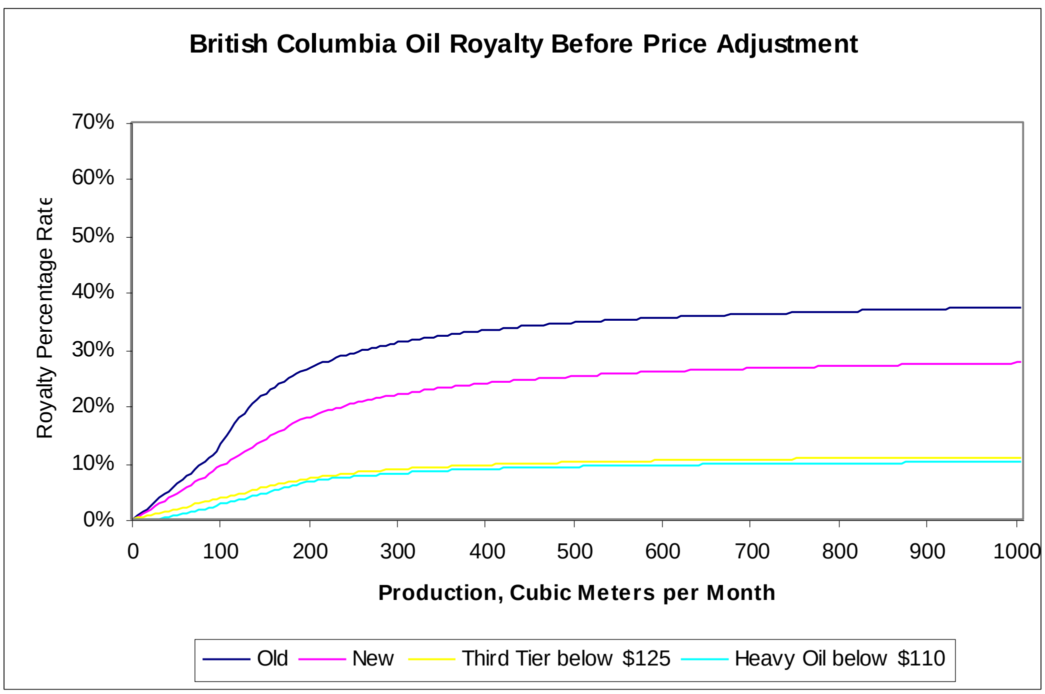


Chart B-1

- New Vintage introduced in October 1975. Third Tier Vintage introduced in December 1999.
- All classes use a straight-line plus asymptotic form.
- Following table shows the anchor points and incremental rates for the different classes of BC oil.

	Old	New	Third Tier	Heavy
First Anchor Point for straight line	(0, 0%)	(0, 0%)	(0, 0%)	(20, 0%)
Second Anchor Point for straight line	(95, 12%)	(159, 15%)	(159, 6%)	(200, 6.75%)
Incremental Rate	40%	30%	12%	11%

Table B-2

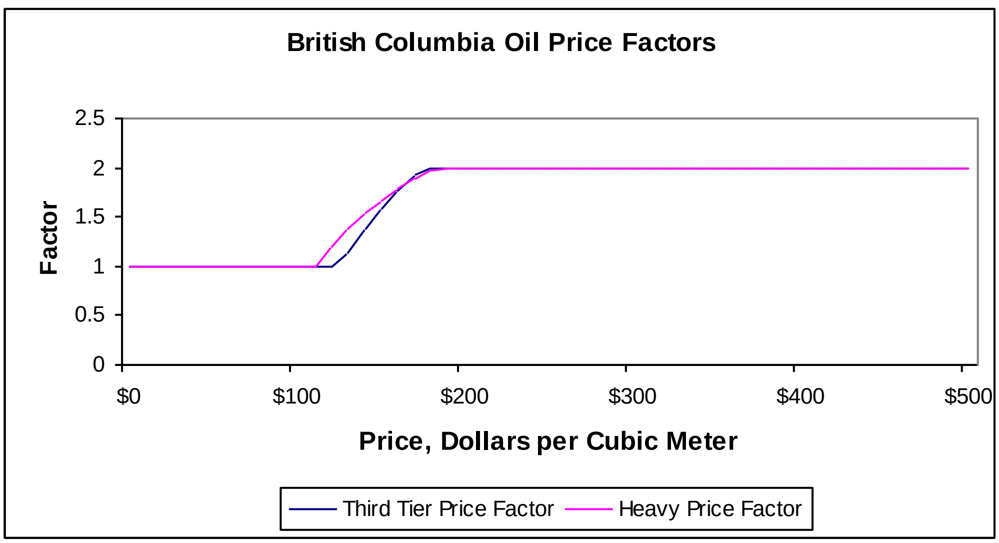


Chart B-3

- Old and New oil royalty rates are not sensitive to price.
- Third Tier and Heavy are not sensitive to price below the price threshold.
- The threshold is $125 for third tier and $110 for heavy.
- Third Tier price factor increases to the maximum of 2 at $175.
- Heavy price factor increases to the maximum of 2 at $183.34.

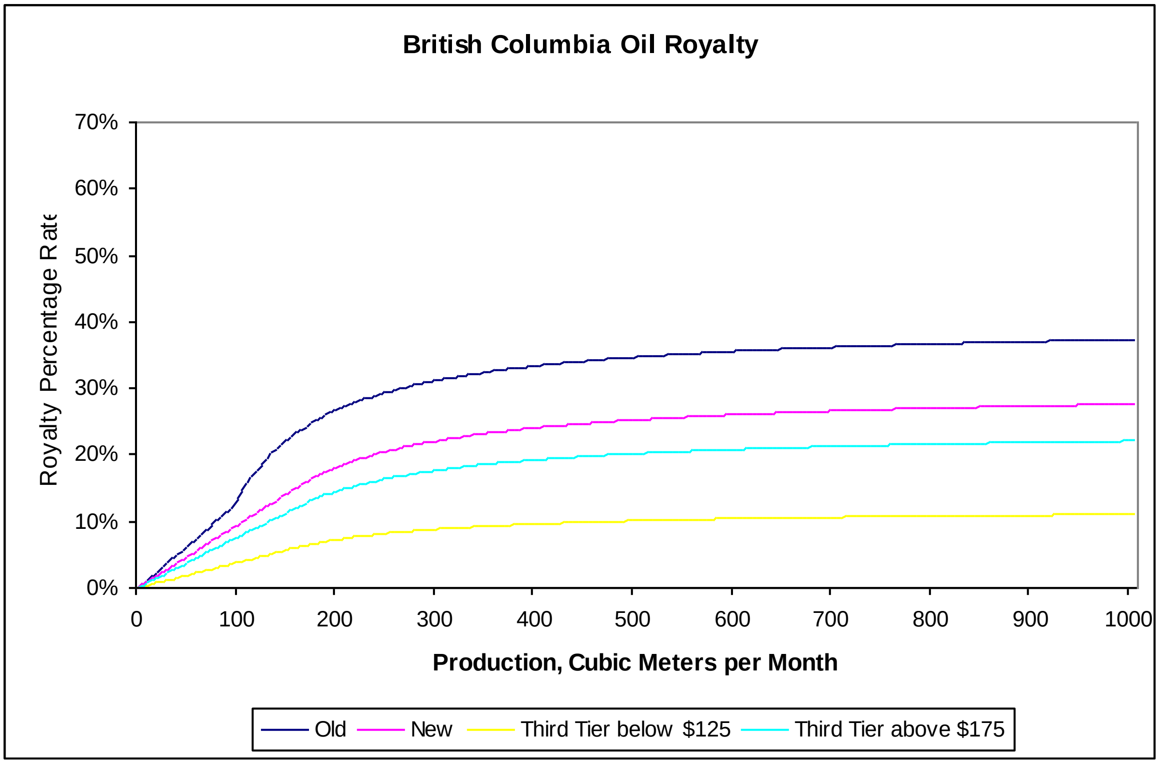


Chart B-4

- Because old oil and new oil are not affected by price, the chart of total royalty for old oil and new oil royalty is the same as chart B-1.
- For third tier oil, the chart shows the total royalty at the minimum and maximum rates for which the royalty is sensitive to price.
- At all prices above $175, including the current prices, the third tier royalty rates are the same as the rates for $175.
- Because the price factor is 2, these rates are twice the rate for the basic third tier royalty (below $125) shown as the bottom line of Chart B-1 and of Chart B-4.
- For clarity, total royalty for heavy is not included in Chart B-4. The total royalty for heavy is show following, as Chart B-5.
- Formulas, where V = volume produced, P = Price, F = Price Factor

Old	R%=V/792 if V<95, else R%=(11.4+0.4(V-95))/V
New	R%=V/1058 if V<159, else R%=(23.9+0.3(V-159))/V

Third R%/F=V/2645 if V<159, else
R%/F=9.56+.12(V-159))/V, and
F=1 if P<125
F=1+3.5(P-125)/P to a maximum of 2

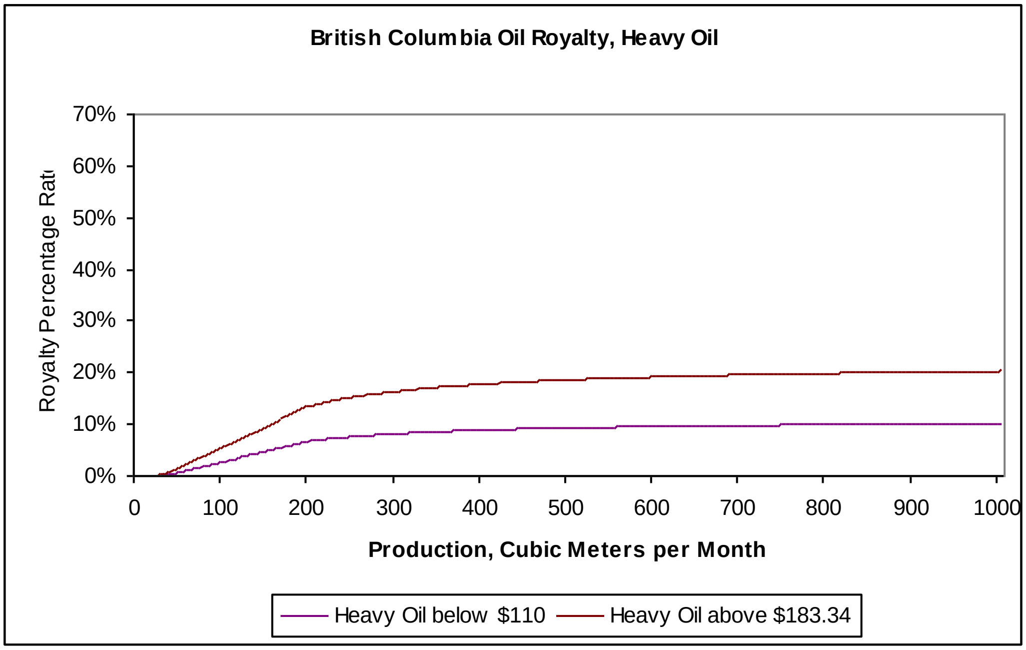


Chart B-5

- Heavy oil rates are slightly below the third tier rates.
- Rate is zero until production reaches 20 cubic meters per month.
- Increases in a straight line to 6.75% at rate of 200.
- Goes to an asymptotic maximum of 11%.
- Multiplied by a price factor that goes from 1 to 2 between the prices of $110 and $183.34.

Other factors that affect British Columbia Oil Royalty

- Discovery Wells have royalty rate of zero for three years or 11,450 cubic meters.

Gas Royalty

Gas is classified using three vintage categories (pre-1998, pre-2004, post 2004), two drilling categories (first term, not first term) and two geological categories (conventional, coalbed methane). British Columbia gas is sensitive to the well rate of production only at low levels of production. Subtracting a low productivity reduction factor from the royalty rate defined by a price-sensitive formula provides production sensitivity.

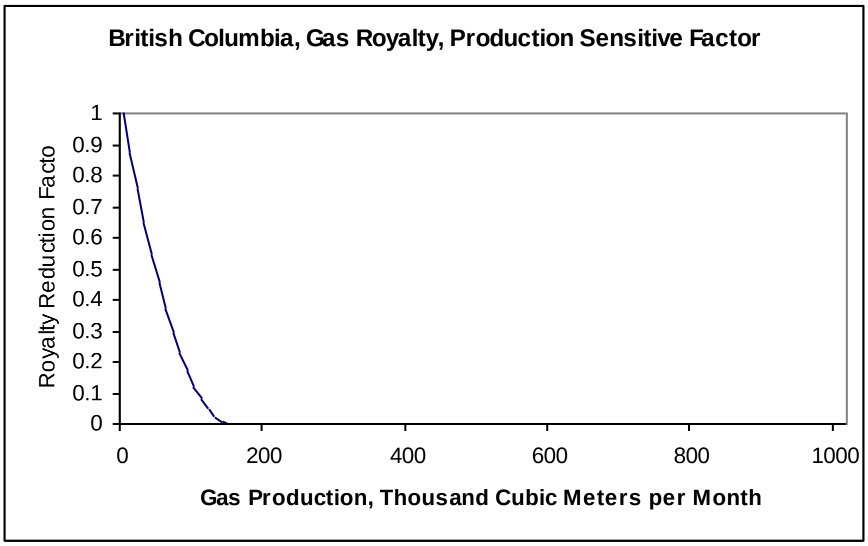


Chart B-6

- Factors define the proportion by which the price-sensitive royalty rate is reduced at low levels of production.
- A factor value of 1 reduces gas royalty to zero at zero production.
- Beyond the production thresholds, the factor is zero, so there is no reduction.
- Low productivity factor affects any well that produce less than 5 E3M3 per Day (=155 E3M3 per month).
- Higher thresholds are defined for Coalbed Methane Wells and Marginal Well Events.

♦ Formula is:

RR%=R%-R%((T-V)/T)^2, where
RR% = Reduced Royalty%,
R% = Rate from price sensitive formula,
V= ADV = Average Daily Volume in E3M3 with maximum value T
^ means taking of powers:
T = 5 generally
T = 17 for coalbed methane wells
T = 25 for marginal well events.

The various categories of natural gas wells use four price-sensitive royalty formulas. Because the classification criteria are more complex than the formulas, giving the name of its formula most easily indicates the class of the gas. The name of the formula comes from it's the minimum royalty rate.

Formula	Classifications that Use the Formula
Base 15	Gas well spud date before Jun 1, 1998 Gas for which revenue is shared with the Blueberry River Indian Band, the Doig River Indian Band, or the Fort Nelson Indian Reserve.
Base 12	Gas that is not Base 15, Base 9, or Base 8
Base 9	Drilled in first term of lease and with spud date between May 31, 1998 and before Jan 1, 2004
Base 8	Conservation gas

Table B-7

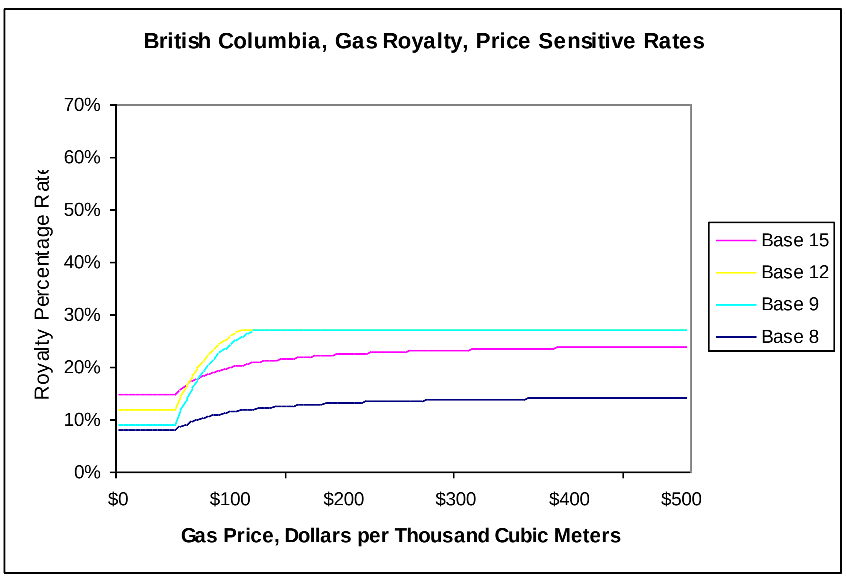


Chart B-8

- ♦ At zero price, all rates are at the base rate.
- ♦ Rates are flat below the Select price of $50.
- ♦ Above the select price, a higher portion of the incremental price is taken.
- ♦ The marginal rates with respect to price are:
  - for Base 15, 25%
  - for Base 12, 40%
  - for Base 9, 40%
  - for Base 8, 15%.
- ♦ Base 15 and Base 8 tend toward the asymptotic maximum equal to their marginal rates.
- ♦ Base 12 and Base 9 gas are constrained to a maximum rate of 27%.

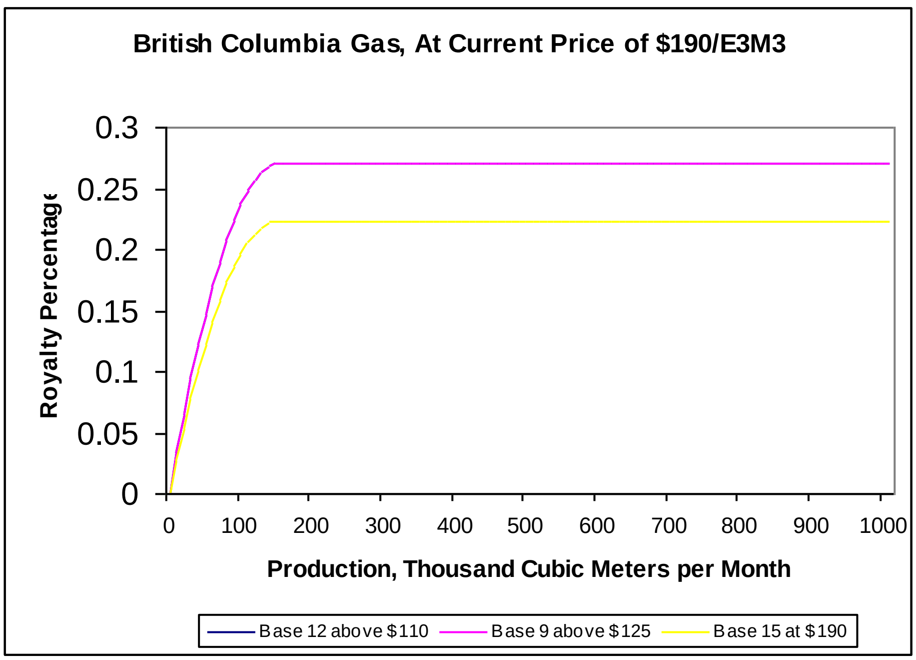


Chart B-9

- At current prices, Base 12 and Base 9 are at their constrained maximum rate of 27%.
- Total royalty for Base 12 and Base 9 overlap.
- Base 15 gas price sensitive rate has been in the range of 21% to 23% at the price levels of 2001, 2002, and 2003. At the current price of $190, the Base 15 rate is 22.4%.
- The rates for Base 12 and Base 9 have become higher than the Base 15 rate because they have a higher marginal rate.

Other Programs that Affect BC Gas Royalty

- B.C. gives royalty credits for deep wells drilled between June 2003 and July 2008.
- B.C. gives royalty credits for work done in the summer months.
- B.C. increases cost allowance by $50,000 for coalbed methane wells.

Appendix 2.4—Alaska Formulas

The Alaska Severance for gas is sensitive to the gas well rate of production. The tax is calculated as an “Economic Limit Factor” multiplied by the basic gas tax rate of 10%.

The economic limit factor = 1-(3000/P) where P is the well rate of production in mcf per day. The following chart AK-1 gives the value of the factor, where the well rate is expressed in thousand cubic meters per month. Note that the well rates shown are ten times as high as the well rates shown in the graphs for Alberta and British Columbia.

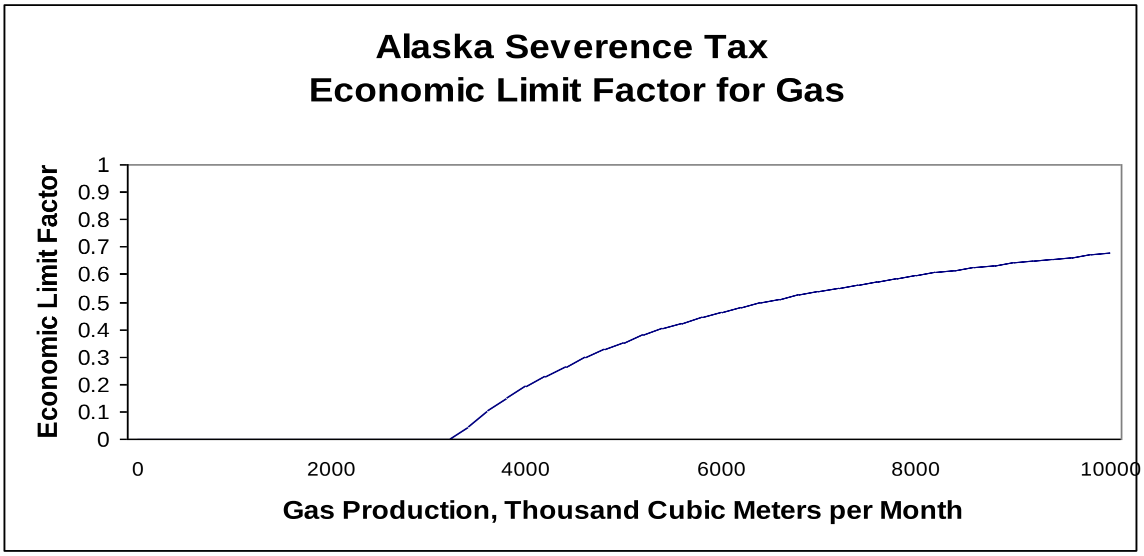


Chart AK-1

Chart AK-2 gives the tax rate as percent of sales value.

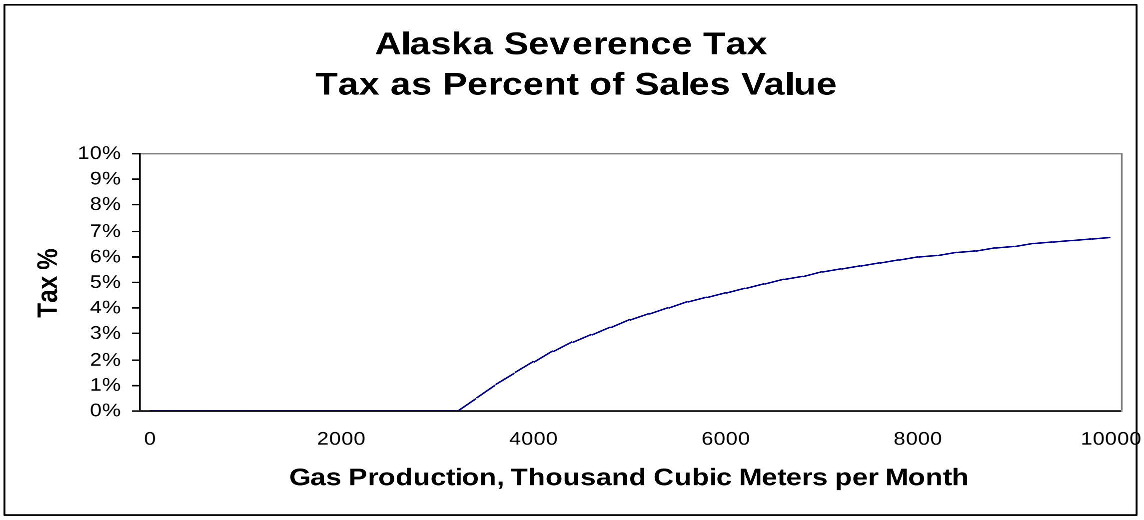

Alaska Severence Tax
Tax as Percent of Sales Value
Tax %
10%
9%
8%
7%
6%
5%
4%
3%
2%
1%
0%
0
2000
4000
6000
8000
10000
Gas Production, Thousand Cubic Meters per Month

Chart AK-2

Appendix 2.5—Norway Formulas

State Directed Financial Interest

In addition to having a Statoil as the operator of most developments, Norway has also created an ability to take a non-operating working interest in developments. This non-operating state interest is managed by a special company, Petoro AS. In addition to fulfilling the role of a working interest in certain licenses, Petoro acts as counsel to the Government with respect to any transfer of license interests for all petroleum licenses. It has a general right of pre-emption for all proposed transfers of license – i.e., it may choose to acquire the rights under the same terms as the proposed sale/transfer of the rights.

Cost of Capital Provisions

Norway's special petroleum tax allows developers to deduct all costs that are deductible when computing income tax, including interest expense. In addition there are three provisions that relate to the developer's use of equity finance developments.

First, the special petroleum tax allows accelerated depreciation. Exploration expenditures are 100% deductible in the year that they are incurred. Capital expenditures for production facilities are depreciated on a straight line basis over six years.

Second, a cost uplift of 5% is applied to un-depreciated capital expenditures.

Third, a limit is placed on the ratio of interest to equity that is allowed as expense. Called the "thin capitalization" rule, the full amount of interest expense is not deductible unless a company has equity to asset ratio of at least 20%.