Alberta Energy

Alberta's Royalty System –Jurisdictional Comparison

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PRICEWATERHOUSECOOPERS

Table of Contents

1 Executive Summary

Royalties are an important part of Alberta's overall fiscal framework. They ensure that Albertans, represented by the government, receive a portion of the benefits arising from the development of the province's resources. They are also an important policy tool that can shape economic and resource development.

Determining an appropriate level of government take within any royalty system is a complex task. Economic theory provides some insight, but the ultimate decision depends on the values and priorities of the government and citizens. Moreover, the social, political and economic context in which these decisions are made changes over time. As a result, Albertans continuously examine the policies and programs executed by their government.

To this end, sufficient information and analysis on the royalty system, including its design, structure, objectives, and performance, is important so that perspectives can be shared on an informed foundation. Indeed, improving transparency and accountability was a key theme of the 2008 report entitled "Building Confidence: Improving Accountability and Transparency in Alberta's Royalty System" (the Valentine Report).

PricewaterhouseCoopers (PwC) was engaged to review selected recommendations from both the 2006 report of the Auditor General of Alberta and the Valentine Report which relate to the royalty system and the measures used for reporting the effectiveness of that system. Specifically, this study:

- Reviewed the broad objectives of a royalty system;
- Developed a framework for comparing royalty systems;
- Compared Alberta's "take" relative to the experiences in other jurisdictions; and
- Examined the appropriateness of the 20% - 25% target range established in Alberta Energy's business plan for Alberta's share of industry revenue.

This review did not attempt to determine an optimal level of government take, develop or recommend performance targets, nor, conduct a comprehensive economic / competitive analysis. While work in these areas is important, they were not within the scope of this review.

The combination of all royalties, fees and taxes paid by the private developer to the government is called total "government take". It is government take – not only royalties or taxes paid - that matters from a public policy perspective.

Royalty systems, namely the level of government take, endeavor to strike balance between two, and at times, competing objectives: returning a share of the profits to the resource owner and encouraging the development of the resource. Resource owners that favor an accelerated pace of development may opt for a system that captures a relatively low government take, leaving more income in the hands of the developer. On the other hand, owners may wish to receive a high financial return at the expense of less development.

Determining what level of government take is appropriate typically employs a comparison to other resource producing jurisdictions. However, these comparisons are often not precise. Indeed, comparisons to Alberta, particularly at the international level, are difficult to make because of the unique nature of Alberta's resources and the specific environment in which private developers operate. Direct comparison of Alberta's level of government take to other jurisdictions could lead to inaccurate conclusions regarding Alberta's royalty system and the policy context upon which it is based.

This does not suggest that comparisons should not be made. It is imperative that the government continually monitor other jurisdictions to ensure that the royalty system is meeting the intended objectives. However, royalty policy should consider the context of several factors that also influence the balance between development and return to owners.

This report introduces a framework for comparing Alberta's government take to other jurisdictions. In particular, government take was examined in the context of several factors, including type of resource, costs, protection of property rights, legal enforcement of contracts, capital market controls, business regulations, and political risk. This framework offers the following advantages:

- Highlights areas of relative jurisdictional strengths and weaknesses;
- Helps facilitate understanding and communicate the complexity of royalty decisions to resource owners; and
- Guides royalty policy discussion and debate.

For Alberta's royalty system, the challenge of balancing return to owners with development is articulated in the first goal in the Ministry of Energy's 2009-13 Business plan, which states: *Alberta has a competitive and effective royalty system, incenting development and maximizing benefits to Albertans.*

Based on our review, Alberta Energy's performance measure for this goal - the share of industry revenues collected by royalty system – has limited utility for the following reasons. First, it ignores other forms of revenue received by the government (e.g. bonus fees, taxes). Second, it does not adequately measure against the objectives of development and return in a highly competitive environment. Third, the use of a 20-25% target for royalty collection as a share of industry revenue does not account for the dynamic nature of the royalty regime, particularly the need to respond to geological conditions, costs and the evolving competitive environment.

In terms of the jurisdictional comparisons, government take is useful because it is the one element (unlike differences in geology, politics, business climate, etc.) that is common to all jurisdictions and considers all payments made by energy companies to the government. However, it should not be viewed in isolation. Rather, government take in the larger context of the jurisdiction's political and economic climate and resource in question can serve as an indicator for further study and review.

2 Introduction

2.1 Project Purpose

Royalties are an important part of Alberta's overall fiscal framework. They ensure that Albertans, represented by the government, receive a portion of the benefits arising from the development of the province's resources. They are also an important policy tool that can shape economic and resource development.

From a policy perspective, royalties cannot be treated in isolation from other types of payments made by energy companies to the government. Companies do not distinguish between the various payments, (including royalties, taxes and fees) they make to the government. It is the combination of all these payments, often referred to as total "government take", that weigh into a company's decision of where and how much to invest. If government take in a jurisdiction is too high, companies may choose to invest elsewhere. Alternatively, if government take is set too low, resources may be over-exploited and the government may not share appropriately in the benefits.

Determining an appropriate level of government take within any royalty system is a complex task. Economic theory provides some insight, but the ultimate decision depends on the values and priorities of the government and citizens. Moreover, the social, political and economic context in which these decisions are made changes over time. As a result, Albertans continuously examine the policies and programs executed by their government.

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3 Royalties, Taxes and 'Government Take'

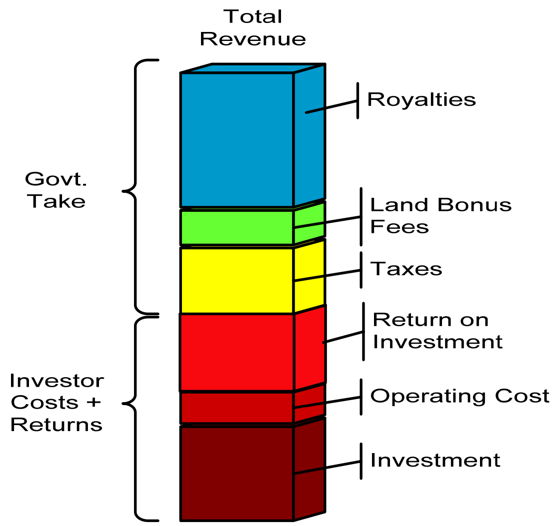
In most cases, a company owns or leases assets that are used to produce goods and services. After recovering costs and paying taxes, companies are entitled to the full return or profits generated from their assets. For companies that develop natural resources, however, the resource is usually owned by the government. As a result, if a company wants to develop the resource, it must pay a price, or a portion of the economic value of the resource, to the government. This price is referred to as a royalty, representing the cost that must be paid to the resource owner in exchange for the right to develop the resource.

While royalties are levied and collected by the government, they are not a tax. Taxes are collected from individuals and business to cover the cost of public spending, such as infrastructure, healthcare and education. Royalties, on the other hand, are the cost of obtaining the benefits associated with a property right - in Alberta's case, the right to develop a resource that is owned by the government representing all Albertans. So while royalties and taxes both contribute to government revenues and may fund similar programs, the fundamental rationale for collecting taxes and royalties is different.

Despite the key distinction between royalties and taxes, the two cannot be treated in isolation. Both are part of the government's overall fiscal system and contribute to total "government take", or the overall price paid by the developer. Figure 1 provides a simple illustration of how resource revenue is divided between industry and the government. The first share of revenue flows to the company, allowing it to cover costs (initial investment and operating) plus earn a return on investment. The remainders of industry revenues fall under government take, consisting of royalties, taxes and land bonus fees.[1] The relationship between government take and private return is shown in Figure 1; namely, that as the total government take increases, the return to the private developer declines.

The government has two main channels for altering the level government take: it can change the level of taxation; or it can adjust royalties. Royalties, however, apply only to the natural resource sector, while taxes are more uniformly applied across industrial sectors.

Figure 1: Distribution of Revenue

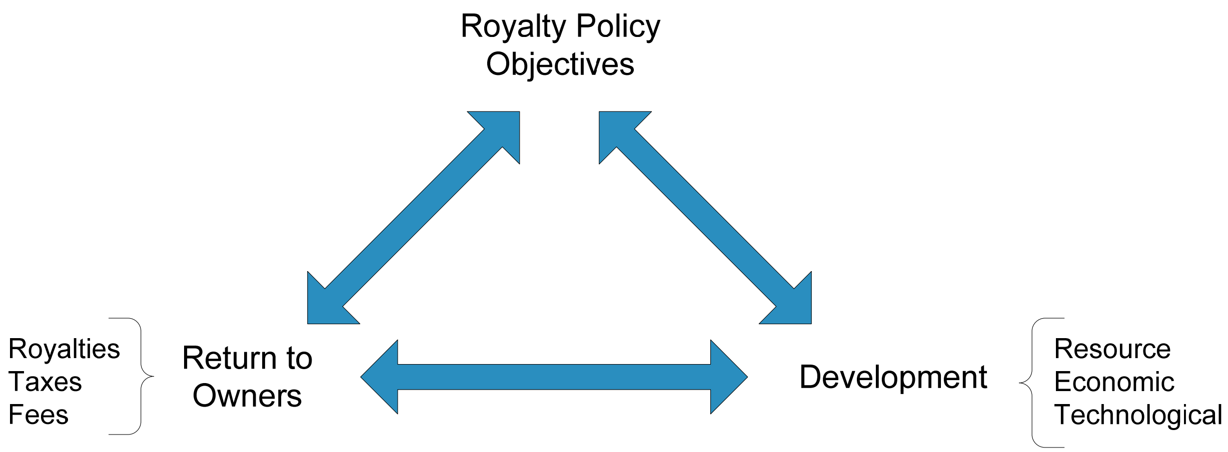


[1] See Section 4 for a detailed description of all three forms of government levies.

4 How Policy Objectives Shape the Royalty System

The royalty system ensures that the owner of the resource, in Alberta's case the government, receives a share of the profits or revenue earned during the process of development. However, striking the right balance between share of the profits to the resource owner, while encouraging the development of the resource can be a challenging process. High levels of government take may restrict development, while low levels can prevent the owner from sharing in the economic return generated from their assets. In this section, we review the two main, and at times competing, objectives of royalty systems: providing a return to resource owners; and encouraging development (See Figure 2).

Figure 2: Policy Trade-Offs



4.1 Return to Owners

It is clear that one of the objectives of the royalty system is to provide a return to the resource owner. What is less clear is what the proportion of the total return, or government take, should be. Economic theory suggests that a resource owner should be entitled to the full portion of the return over and above what is considered "reasonable".[2] Reasonable return is often defined as the minimum return required to compensate a developer for the risk it faces while developing the resource.

Setting royalty rates to accomplish this goal is complex. Typically, at the early stage of development when costs are high and production levels are minimal or uncertain, the owner may wish to levy low royalties and taxes in order to attract investors and stimulate development.[3] For more mature and proven resources, the owner may be able to levy higher royalties and capture a greater share of the profits without discouraging development.

In a simple example, a company might require a 10% return to develop a crude oil reserve, after factoring all the associated project risks. If the projected return is 25%, the government could set royalties to capture the full 15% "remaining return", leaving the company with a large enough profit incentive to invest. However, if the government sets royalty rates to capture 20% of the return, the company will be left with only 5% and may be

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[2] Economists use the term "economic rent" to describe the portion of the return that exceeds the normal, or reasonable, rate of return.
[3] In the early stages of a project, the owner can extract revenue from the developer through profit-insensitive levies such as property taxes, bonus fees and fixed (e.g. non-production) royalties.

forced to pursue opportunities elsewhere. The challenge for the government is to understand the level of risk to the developer and adjust the level of government take accordingly.

4.2 Development

The royalty system, through its impact on total government take, can have a direct impact on the pace of development, jobs created and the level of private investment. In a recent study, Alberta Energy found that higher royalties were associated with a decline in well activity.[4]

Of course, the level of government take is only one of many factors that affect development. Access to resources, geology, commodity prices, political climate, currency exchange rates, and labour costs also influence whether a company will choose to invest in a jurisdiction's resource.

The stability of the royalty system also influences development. In general, stable and certain policy environments are preferable. Frequent changes to the royalty system (shifts in royalty rates, incentives, tax bases, etc) may create uncertainty and hinder investment.

While most jurisdictions design their royalty systems to achieve some level of development, the type of development desired depends on the issues facing a particular jurisdiction. Alberta, for example, introduced a new royalty regime in 1997 to accelerate the development of the oil sands in a period of low crude oil prices. In the U.S., concerns over dependency on foreign sources of non-renewable energy have led to a system that strongly favored domestic production. As a result, the U.S royalty system now includes several targeted royalty and tax incentives to encourage the development of federally-owned offshore oil and natural gas reserves (EIA 2006).

When setting royalty policy to meet development objectives, a key consideration is a jurisdiction's existing stage of resource development. For countries with underdeveloped resources, a system with low levels of government take may be favored in order compensate developers for the higher degree of production uncertainty and incent investment. Likewise, in countries where reserves are more mature and hence production uncertainty is low, a higher level of government take may be preferred.

For most jurisdictions, the general trend is for government take to increase as resources become more developed, reflecting the lower degree of uncertainty in the later stages. However, there is recognition that in some jurisdictions (including Alberta) ongoing development of resources can lead to lower production rates and higher costs. In these cases, government take may decrease to encourage continued development.

In Alberta, the royalty system is used to fulfill a number of development objectives (Alberta Royalty Review Panel, 2007):

- To extend the life of mature oil and natural gas pools to maximize recovery;
- To promote the development of new and more efficient technologies; and,
- To promote the exploration and development of new reserves.

[4] Using data on natural gas well activity, prices and net revenue between 2001 and 2007, the DOE concludes that a 1% increase in royalties is associated with a 0.73% decline in well activity. Assuming drilling activity of about 20,000 wells per year, a 1% royalty increase would result in 150 fewer wells drilled. Source: Alberta Department of Energy, Technical Report #3: Alberta's Conventional Oil and Gas Industry – Impact of Potential Royalty Change on Industry Activity.

5 Overview of Alberta's Oil and Gas Fiscal Regime

Alberta's royalty system accounts for a significant proportion of payments made by energy companies to the government. However, corporate taxes, other taxes, and bonus fees are also of significance since they, like royalties, contribute to the total burden faced by companies that develop Alberta's resources. As a result, policy makers normally consider the royalty system as part of a broader oil and gas fiscal regime of royalties, taxes, and fees.

The structure of a royalty system varies by jurisdiction. In Alberta, royalties are mainly paid to the government, which owns most of the resource on behalf of its citizens.[5] This contrasts with the U.S. where most land rights are privately held and developers pay negotiated royalties to private owners.[6]

Table 1 and Figure 3 illustrate the different types of royalties, taxes and fees that are levied on oil and gas companies in Alberta at different stages of exploration and development[7]:

Table 1: Alberta's Oil and Gas Fiscal Regime – Taxes, Royalties, and Fees

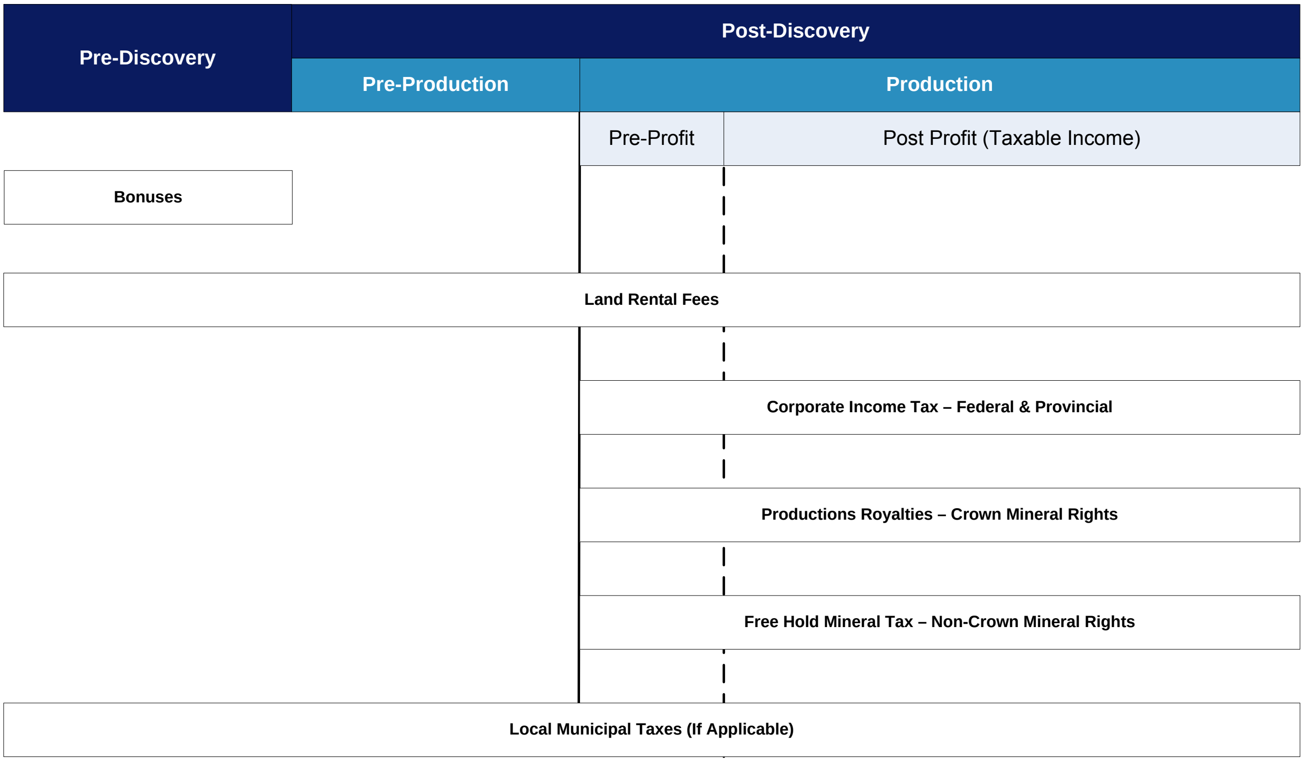
Levy	Stage	Description/ Calculation
Bonus Fees	Prior to production, acquiring resource rights	To acquire the rights to develop the resource, the company must place a bid through a competitive auction. Annual rights (per hectare) are leased to the highest bidder.
Land Rental Fees	Pre-production and production	A fixed fee per hectare of land is applied for oil and gas leases, both for conventional oil and gas and oil sands.
Production Royalties	Production	Applies to resource development of Crown lands. The value of revenue or net revenue is multiplied by the relevant royalty rate to determine the production royalty.
Corporate Income Tax (CIT)	Production, once taxable income is generated	Relevant CIT rates are multiplied by taxable income to determine federal and provincial CIT payable.
Feehold Mineral Tax (FMT)	Production for companies on non-crown land.	Applies to developers on non-Crown land. The FMT rate is multiplied by the value of production to determine FMT payable.
Municipal Property Tax	Pre-production and production	Value of land multiplied by relevant mill rate to determine property tax bill.

[5] In 1930, ownership of natural resources was transferred to the prairie provinces of Alberta, Saskatchewan and Manitoba. As a result, it is the Government of Alberta, on behalf of its citizens, that levies and collects royalties for resources developed on crown land. For non-Crown lands, which account about 19% of the minerals in Alberta, the relevant owner (e.g. First nations, freehold land owner, national parks) collects the royalty and the Alberta Government charges a Freehold Mineral Tax (FMT).

[6] Individual U.S. states collect a Severance Tax on the income remaining once the royalty is deducted. The severance tax compensates the State government, for the cost of "severing" its original ownership of the resource as well as to cover the cost of related public services.

[7] See Oil and Gas Fiscal Regimes: Western Canadian Provinces and Territories produced by Alberta Energy for more detail on specific rates.

Figure 3: Alberta's Fiscal Regime - Levies by Phase of Development



5.1 Conventional Oil

In terms of Alberta's supply of conventional oil, the Western Sedimentary Basin is relatively mature and geologically well known. This means that the large mature fields have already been developed and that remaining conventional pools are being developed at a slower rate. While conventional production will continue, this requires development of relatively smaller pools within those fields. Furthermore, given that some conventional oil can not be extracted using existing methods, continued technological advancement is required to sustain conventional oil production.

The royalty formula for conventional oil is based on three components: the quality of the product, the price of the product, and the level of production. The royalty rate is applied on a sliding scale which is designed to accommodate a wide range of price and production combinations. Generally, heavier oil has a lower royalty rate than lighter oil, reflecting its lower product value.

Estimates indicate that approximately 70% of the remaining oil reserves in Alberta can only be extracted using advanced recovery techniques (New Royalty Framework, 2008, p.9). As such, the government's royalty policy no longer distinguishes between old and new oil reserve vintages. This distinction was in place to discourage investment in low productivity sources and technologies while encouraging investment in new reserves. While Alberta has eliminated a number of programs designed to offset the costs associated with developing conventional sources, specific programs have been retained to encourage research and additional oil recovery (i.e. Enhanced Oil Recovery Program and the Innovative Energy Technology Program).

5.2 Heavy Oil

By some estimates, Alberta's reserves of oil sands account for about 30% of the world's supply of heavy oil (Oil Field Review, 2006, p.34). Unlike other sources of heavy oil, Alberta faces virtually no exploration risk as all deposits are well known. Other parts of the world, however, pay a risk premium to develop heavy oil resources as the geology is not as well understood.

Compared to conventional oil, oil sands require significantly higher levels of capital investment to develop and produce into marketable products. Oil sands royalties are based on a combination of a traditional fixed royalty rate and profit sharing, to reflect a balance between a portion of profits and the significant start-up costs and long-term development time frames inherent in an oil sands project.

Alberta's oil sands royalty formula is based on industry gross and net revenues. For pre-payout, the rates vary on a sliding scale from one percent when the price of oil is above $55 /barrel and increases up to 9% when the price reaches $120 / barrel. For post-payout, the rate starts at 25% of net revenues when oil is $55/ barrel up to 40% when the price of oil is $120 / barrel (or higher) (New Royalty Framework, 2008, p.9).

5.3 Natural Gas

Alberta contains a large supply of natural gas, accounting for about 80 % of the natural gas produced in Canada. Studies indicated that there are approximately 39 trillion cubic feet (Tcf) of proven reserves in Alberta representing 44% of Alberta's 87 Tcf ultimate potential (Alberta Energy 2008). Alberta also holds significant non-conventional supplies of natural gas, such as coal bed methane. Alberta's coal deposits could yield an additional 500 Tcf of natural gas, but at present it is not fully understood how much of this source is feasibly recoverable. Another potential source is gas in shale which is still in the very early stages of development in Alberta.

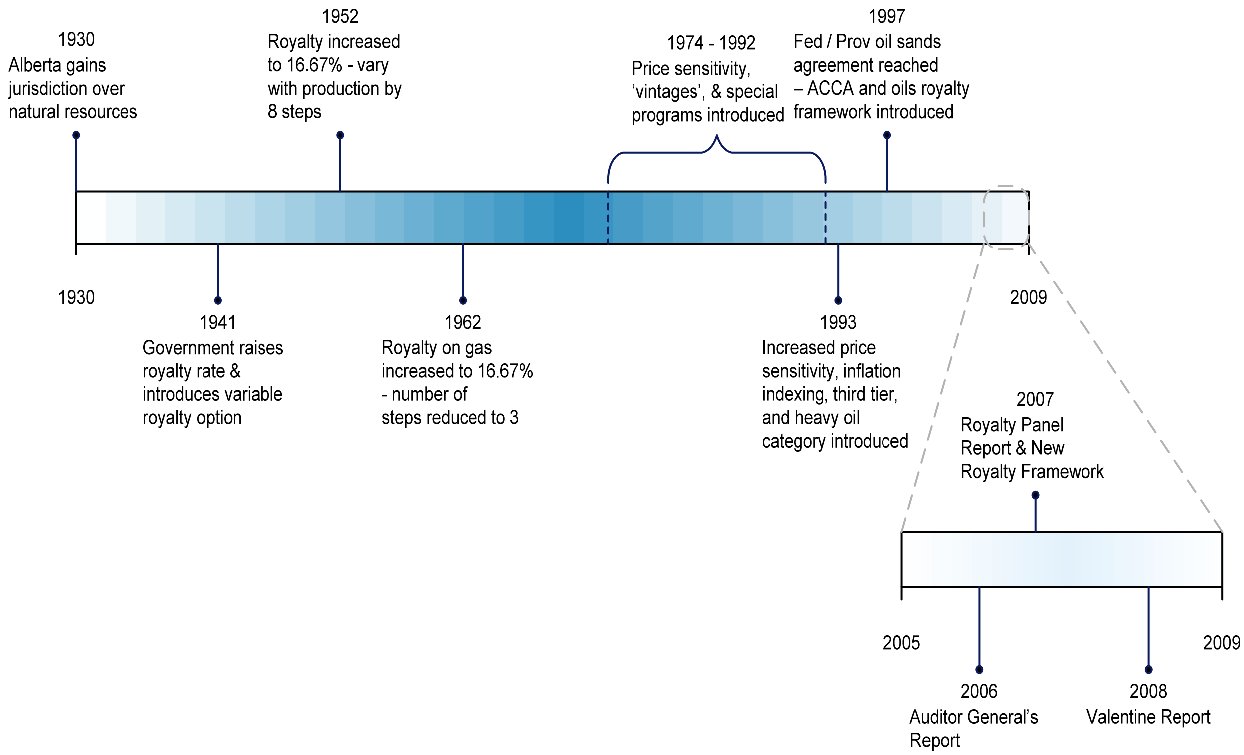
Natural gas royalties are similar to conventional oil royalties insofar as the formula accounts for price and production volume. Royalty rates currently range from a combined five per cent to 50 per cent of net revenue, depending on product price and production, with rate caps at $17.75 per Million British Thermal Units (Alberta Energy 2009).

6 Evolution of Alberta's Royalty System

6.1 Major Policy Changes

The history of Alberta's royalty regime dates back over 70 years (see Figure 4). When Alberta entered Confederation in 1905, the federal government retained rights over natural resources. However, with the passage of the Natural Resources Transfer Act in 1930, the Western Provinces of Manitoba, Saskatchewan, and Alberta gained exclusive jurisdiction over their natural resources.

Figure 4: Timeline of Major Policy Changes to Alberta's Royalty System



The government first set its royalty rate using a five percent flat rate (of net revenue) for both oil and gas, which was later raised to 10% by 1935 (Alberta Energy 2007). In 1941, the government raised the royalty rate to a flat 12.5% and introduced a variable rate option where producers could choose between the 12.5% flat rate or a variable rate of five to 15 percent based on production (Alberta Energy 2007). By 1972 the royalty rate had increased to 25% of industry net revenue in response to increasing world prices.

The period between 1974 and 1997 saw many important variations to the royalty system responding to changing conditions in the oil and gas industry. In an effort to level the playing field, the government introduced price sensitivity features to account for the volatility in prices throughout the 1970's and 1980's. The government then introduced the 'vintage' concept to reflect the maturity, productivity and changing characteristics of existing conventional sources. Numerous special programs were implemented in the 1980's to encourage exploration and development. Overall, this period reflected a shift towards making oil and gas production incentives responsive to market conditions and the resource maturity.

By 1997, the federal and provincial governments reached an agreement with respect to oil sands development including harmonized tax treatment (i.e. accelerated capital cost allowance) for oil sands similar to other surface mining operations. This policy alignment resulted in charging one per cent of a project's gross revenues until the project's investment costs are then paid in full at which point rates increase to 25 per cent of net revenue. These policy changes and higher oil prices subsequent to 2003 helped accelerate the development of the oil sands industry.

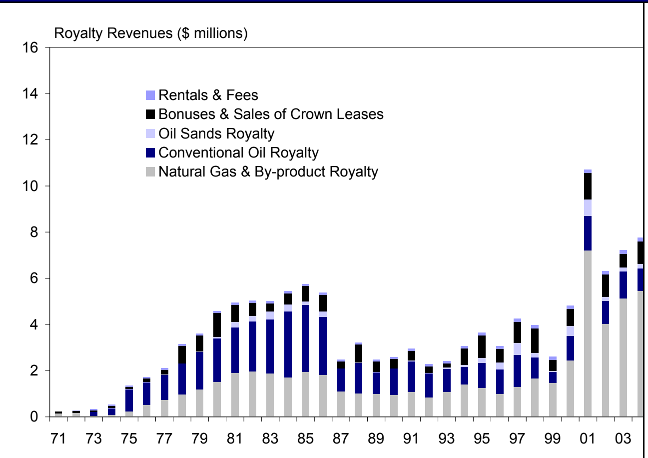
In 2006 and 2007, both the Auditor General of Alberta and the Royalty Review Panel released reports examining the royalty system. In response, the government implemented a new royalty framework including changes to the royalty rates, elimination of special programs, and encouraging exploration and development of alternative sources / recovery methods. In 2008, the government commissioned former Auditor General, Peter Valentine, to review the implementation of the new framework and to make recommendations to help facilitate its ongoing implementation. The new royalty framework signaled an important development in royalty policy.

The history of royalty policy in Alberta has been marked by a number of incremental changes over time and recent changes represent an attempt to address abnormally high oil prices. Since the new framework was implemented there have been a number of additional changes, reflecting the ongoing challenge of balancing returns (to the resource owner) with development in a period of global economic uncertainty.

6.2 Royalty Revenue Movements and Trends

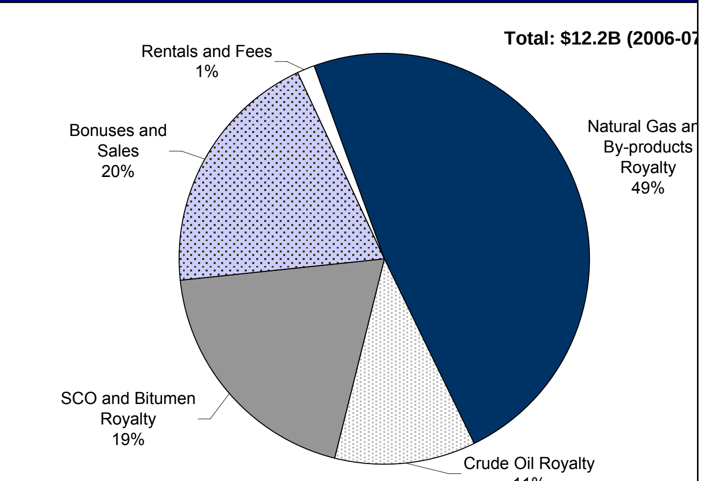
The amount of resource revenue the government collects depends on a number of factors, including production levels, prices, costs and the design of the royalty system. Figure 5 shows the revenues collected through royalties, bonuses and sales of crown leases, and rentals and fees.[8] Total government revenues (excluding taxes) from oil and gas activities have been trending upwards since the late 1990s, with the peak of $14.5 billion reached in fiscal year 2005/06. In 2006/07, revenues dropped to $12.2 billion, with about half attributed to natural gas (and byproduct) royalties, 30% to conventional and non-conventional oil, and the remainder to bonuses, sales, rentals and fees (see Figure 6).

Figure 5: Crown Oil and Gas Revenues By Type and Year



Years represent fiscal years ending March, 2007-08 is an estimate
Source: Alberta Energy

Figure 6: Crown Oil and Gas Revenues By Type – 2006-07



Source: Alberta Finance and Enterprise, Fiscal Plan 2008-

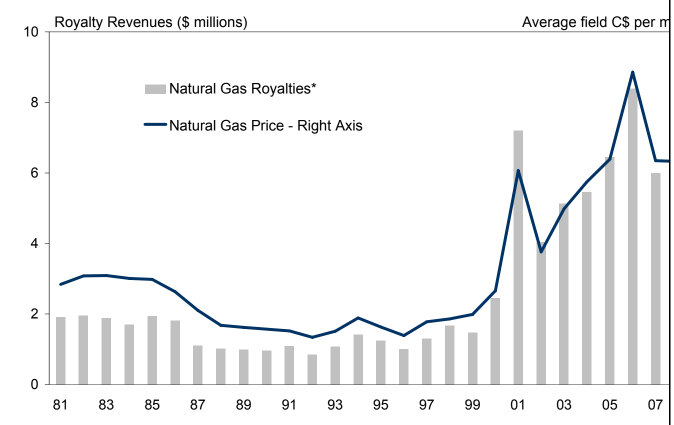
The design of Alberta's royalty system (e.g. the setting of royalty rates and embedded incentives) has a direct bearing on the amount of revenue the Alberta Government receives from resource development. For example, the increase in royalty rates in 1972 and 1974 contributed to an increase in royalty revenues. Another example is when the government changed the royalty system to encourage development of the oil

[8] Corporate taxes are excluded from the figure due the difficulty associated with attributing taxes paid to resource development activities.

sands in 1997. This policy action reduced the share of oil sands revenues flowing to the government in the form of royalties.

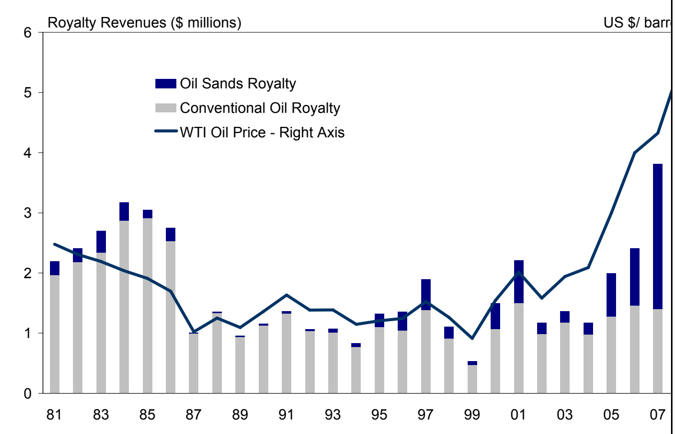
However, the largest impact on royalty revenues comes from oil and gas price movements, as revealed in Figures 7 and 8. Resources revenues have become even more sensitive to prices in recent years due to the introduction of sliding scales – a measure that causes royalty rates to fluctuate with energy prices.

Figure 7: Alberta Natural Gas Royalties and Price



*Includes natural gas by-products
Years represent fiscal years ending March, 2007-08 is an estimate
Source: Alberta Energy

Figure 8: Alberta Crude Oil Royalties and Price



Years represent fiscal years ending March, 2007-08 is an estimate
Source: Alberta Energy

7 Framework for Comparing Jurisdictions

7.1 Government Take

Fiscal systems vary widely across jurisdictions in terms of their complexity, the sharing of risks between the developer and owner, and the types of fees and taxes levied. Despite these differences, the overall tax/royalty burden arising from different royalty systems can be compared using a single measure - the level of 'government take' expressed as a share of total divisible income. By considering all payments made to the government, it represents an important measure of a developer's incentives to invest in a particular project (see box 1).

The main challenge in comparing government take across jurisdictions relates to data availability. Existing studies on government take have limitations insofar as they do not provide information and data (project characteristics and contractual arrangements) in a format that can be efficiently normalized for comparative purposes.

In practice, governments generally capture well below 100% of the divisible income. This is because some income needs to be left in the hands of the private developer so they can earn a reasonable return on their investment. What is considered a 'reasonable' return depends on the level of risk. If there is a high degree of uncertainty regarding future cash flows, for example due to political or geological uncertainty, then a higher private return, and hence a lower level of government take, is required to encourage development of the resource (see Figure 9).

Box 1: The Calculation of Government Take (expressed as share of divisible income)

The best way to calculate government take is using detailed cash flow analysis. Over the life of a typical project, total divisible income (gross revenues less costs) and payments to the government are estimated. Government take is simply the ratio of government payments to divisible income. More sophisticated analysis would discount each of these cash flows, effectively placing a higher weight on government payments or divisible income occurring in the early stages of the project. However, in practice, most estimates of government take are not discounted.

A) Divisible Income

= *Cumulative gross revenues less cumulative gross development and operating costs over life of project.*

B) Government Income

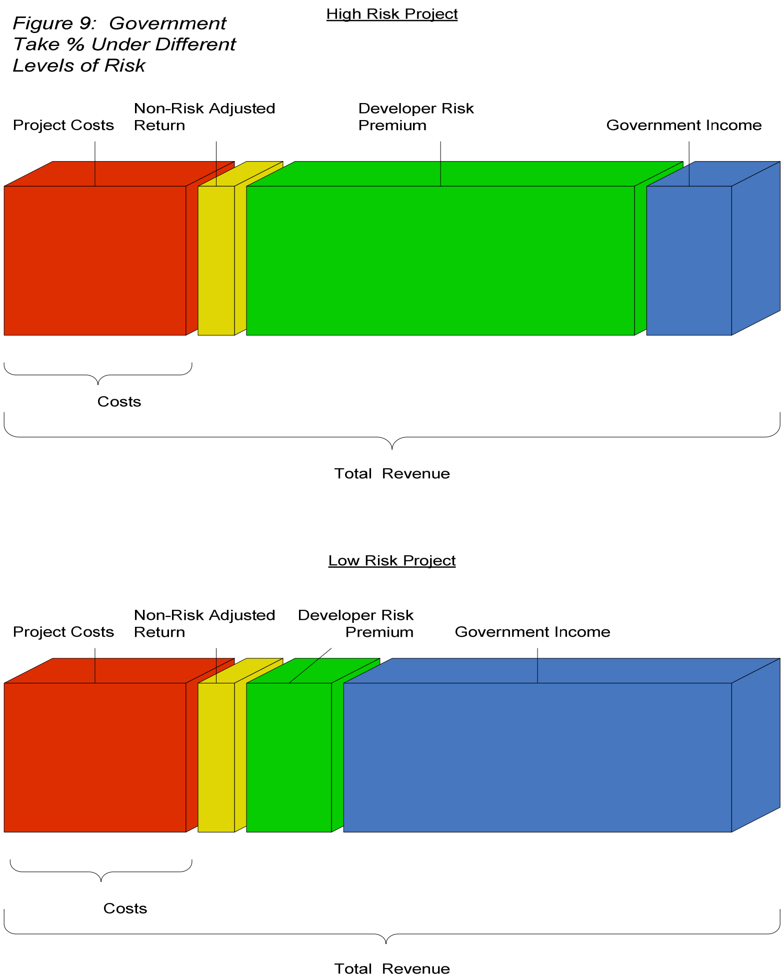
= *All government receipts from bonuses, royalties, taxes, production sharing, etc.*

Government Take (%) = (B/A) *100

Contractor Take (%) = (1-(B/A)) *100

Source: Johnston, D. and Bush, J. (1998). "International Oil Company Financial Management in Nontechnical Language", Penwell Publishers.

Figure 9: Government Take % Under Different Levels of Risk



$$\text{Government Take \%} = \frac{\text{Government Income}}{(\text{Total Revenue}) - (\text{Costs})}$$

Another key consideration is costs. In jurisdictions where the resource is expensive to extract, either due to high cost environment or because the resource is more costly to access (e.g. heavy oil, deep water), a lower level of government take may be required to compensate the developer for bearing this higher cost. In other words, developers that face relatively high costs will need to generate higher cash flows (after taxes, fees and royalties) in order to recover their higher initial exploration and development costs.

Given that government take does not fully account for important risk and cost factors, it cannot be treated as stand-alone indicator of a jurisdiction's competitiveness, or its ability to attract investment. One way to enhance the government take measure is to factor in a risk premium depending on perceived level of risk. If, for example, a jurisdiction has low level of government take, but extremely high levels of political risk or low levels of property protection, a risk premium could be added to the government take calculation to facilitate comparisons to other jurisdictions. The logic behind such an approach is that a developer must earn a higher rate of return or profitability to compensate for operating in a higher risk jurisdiction. The drawback of this approach, however, is that it is inherently difficult to precisely determine the size of the risk premium for each jurisdiction.

7.2 Other Factors

As previously discussed, government take should not be compared in isolation, but rather as one of several factors to provide greater context and meaning for both the government and the developer. The factors considered in this analysis include (Van Meurs, 2008, p.27):

- **Geology, field potential and resource type:**

  Resources that are unproven or difficult to access may require lower levels of government take in order to induce exploration, while easy-to-access and proven reserves may warrant higher levels of government take.

  Some resource types of are lower grade, and require more upgrading before they can be a marketable products. For example, bitumen and heavy oil are viscous and must be heated or physically altered to facilitate further processing. Furthermore, given its impurities, upgrading of heavy oil must occur before it can be turned into a marketable product. Natural gas primarily composed of methane, can also be processed into other marketable products such as ethane, propane, butane, etc.

- **Costs:**

  Costs play an important role when examining a petroleum fiscal system. In the case of Alberta's oil sands, deposits are known and well understood, but are more costly to extract compared to light conventional oil. Moreover, a large portion of North and South American fields of conventional oil have been exhausted and much of what remains can only be exploited using non-conventional (and costly) methods.

  In the case of deep offshore production, fields are relatively small and geographically dispersed, characterized by high costs relative to potential output. Off shore platforms require significant capital investments and extended periods of time to realize production.

  The Middle East, on the other hand, still contains the vast majority of the world's conventional (low cost) crude oil.

- **Political, regulatory, fiscal and/or environmental risks.**

  Developers that face a high degree of risk must be compensated with a higher private return. Therefore, in higher risk jurisdictions, governments may need to leave more divisible income in the hands of the developer to induce exploration and development.

  In countries with a history of instability, and where political and regulatory risk is high, there is a greater probability that the developer's assets will be expropriated, contracts may not be honored, and business dealings will be corrupt. In terms of fiscal risks, developers operating in a country with an unstable fiscal regime face the risk that royalties or taxes may unexpectedly increase. Finally, there may be a risk that the government will unexpectedly tighten environmental standards, resulting in lower production or onerous pollution abatement costs.

  The Economic Freedom Index (EFI)) published by the Fraser Institute. The EFI can be used to examine the level of business risks in jurisdictions around the world. The purpose of the index is to assess whether the policy landscape within a jurisdiction contributes to open and efficient markets.

The above factors were selected on the basis that they are: common to all jurisdictions; and they are measurable using various indices prepared by external agencies. When combined with government take, these factors provide important context when making comparisons to Alberta.

7.3 Petroleum Fiscal Systems

All jurisdictions have a method for collecting revenues generated through the development of their petroleum resources known as a petroleum fiscal system. Before comparing Alberta to other jurisdictions, it is useful to understand the different types of systems in place around the world. Fiscal systems provide context regarding the management of risk (for both the government and the developer) within a jurisdiction. While all petroleum fiscal systems are to some extent unique, they do have common features and can be broadly categorized.

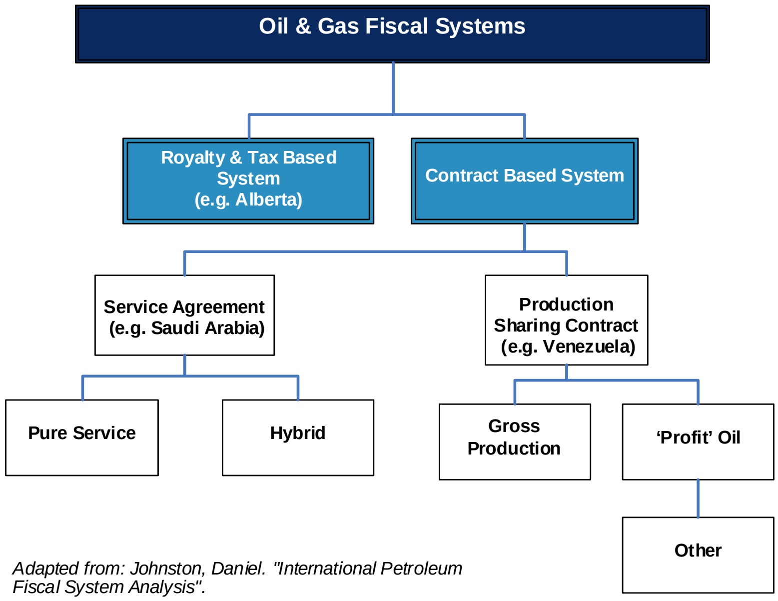
In general, there are two main types of fiscal system: the contractual agreement system and the concessionary (royalty / tax) system. The fundamental difference between the two systems is who holds the title to the resource. (Under a royalty / tax system, title is transferred at the wellhead (i.e. after it is extracted from the ground) (Johnston, 2001, lxiii).))

In a contractual relationship, title to the resource is either transferred at the export point (i.e. when product is ready to be sold in the open market), or not at all, depending on the type of contractual arrangement (see Figure 10). In addition, there are greater incentives to develop the resources to its full potential with contractual systems. Typically, these systems are employed where fields are large and geologically well-known. In this situation, government (often through its state owned oil company) undertakes the initial exploration and development, with outside developers later coming in under contract to further develop the resource and/or lend technical expertise. Contractual systems are more common in jurisdictions with undeveloped or uncertain legal regimes and where concessionary systems are prohibited.

For contractual systems, risk sharing is important to developers since the social and political environments found in many countries do not have legal systems that provide adequate protection for investing corporations. Venezuela, for example, has undertaken a number of nationalization programs across several industries including steel, finance, power, telecommunications, cement, farming and oil. Obviously this represents a great degree of uncertainty on two levels: whether it is even worth the risk to invest if there is a chance the asset will be expropriated once it becomes profitable; and if the asset is nationalized whether the developer will receive fair compensation.

Under a concessionary arrangement, such as Alberta's, the developer is granted title to the field and bears the risk of exploration and development. This system is generally found in higher cost areas where resources are more technically difficult (and in turn more expensive) and requires more sophisticated methods to extract the resource (i.e. ultra deepwater, SAGD, etc.). It is also common in jurisdictions that offer stable legal protection for the developer. Compensation is paid to the resource owner on sales of the resource typically according to a formula that accounts for fluctuations in both price and productivity.

Figure 10: Fiscal Systems



Adapted from: Johnston, Daniel. "International Petroleum Fiscal System Analysis".

Features of each type of fiscal arrangement are summarized as follows:

Service Agreements

- Developer does not take possession of the resource;
- Virtually all risk is born by the resource owner[9]
- Developer is paid in cash for services rendered; and
- This arrangement is often found:
  - In jurisdictions where the costs of exploration are lower than production costs and the owner is typically looking to further expand proven reserves;
  - Where there is a prohibition on foreign ownership of natural resources; and
  - In areas like the Middle East where oil and gas is less costly to produce, but the resource owner requires outside capital, expertise, and/or technology to develop it.

Production Sharing Contracts

- Developers receive oil / gas as remuneration instead of cash. This is especially important in higher risk jurisdictions (political upheaval or civil wars) since the developer receives a tangible (real) product.
- Developers bear the cost of exploration, development and extraction until resources are brought to market.
- Developers are allowed to recover the costs of their efforts (generally up to a certain percentage).
- This arrangement is found in situations:
  - Where the government does not want to bear the risks or costs associated with exploration, and; and
  - Where the government stipulates a role for the state in the development of the resource once it has become commercially viable.

Royalty / Tax Based Systems

- The developer purchases the rights to develop an energy field for a set period of time;
- The developer pays a royalty on products sold (cash or in kind), taxes in corporate income, and other assorted bonuses / fees;
- The developer bears virtually all exploration and development risk;
- This arrangement is typically found in:
  - Higher cost jurisdictions where a developer's legal rights are largely protected; and
  - Political risk is lower and there is less risk that assets will be seized or contracts will not be honored.

[9] It should be noted that this pure (non-risk) arrangement is rare in practice. In practice, some degree of risk / reward is shared with the developer, especially where political risk is involved.

8 Jurisdictional Comparisons

Comparing Alberta to other jurisdictions using a single measure (i.e. government take) is useful. However when considered in context with other useful and important factors such, geology, costs, and risk (political, regulatory, fiscal, environmental) government take can provide greater meaning for both the government and the developer. These factors were selected on the basis that they are: common to all jurisdictions; and they are measurable using various indices prepared by external agencies.

The following jurisdictional comparisons:

- Highlight areas of relative jurisdictional strengths and weaknesses;
- Help facilitate understanding and communicate the complexity of royalty decisions to resource owners; and
- Support royalty policy discussion and debate.

8.1 Detailed Comparison

The following tables provide comparison of government take, cost business climate and fiscal systems of selected regions as compared to Alberta. See Appendices A through E.

Legend

Symbol	Govt. Take (%)	Cost $ (US)	Business Climate Economic Freedom Index overall score
• Much Higher = ⇈	> 76%	> $14.00	-
• Higher = ↑	71% - 76%	$10.68 - $14.00	-
• About the Same = ↓↑	65% - 70%	$7.34 - $10.67	6.0 – 8.5
• Lower = ↓	(64% - 59%)	$4.00 – 7.33	3.5 – 5.9
• Much Lower = ⇊	< 59%	< $4.00B	<3.5

North America

	Type of Fiscal System	Govt. Take	Cost	Business Climate	Discussion & Analysis
US (GoM)	Royalty/Tax	⇊	⇈	⤓⤒	• The United States currently holds 21.3 B/bbl of proven oil reserves and 46.1 Tcf of natural gas. However, much of the oil and natural gas is controlled at the state level or held through private ownership, a situation not found in most jurisdictions. • The social / political situation is very stable and would not lend itself to a risk premium to the developer. • In terms of reserves managed at the federal level, comparing offshore reserves in the Gulf of Mexico, government take may be lower given the costs associated with off shore exploration.
US (Lower 48)	Royalty/Tax	⇊	⤓⤒	⤓⤒	

South America

<table>
<tr><th></th><th>Type of Fiscal System</th><th>Govt. Take</th><th>Cost</th><th>Business Climate</th><th>Discussion & Analysis</th></tr>
<tr><td>Venezuela</td><td>Production Sharing Contract</td><td>↑↑</td><td>↓</td><td>↓↓</td><td rowspan="2">Venezuela's deposits of heavy oil are some of the largest in the world. The Venezuelan government has a large role in the energy industry. Petróleos de Venezuela (PDVSA) is a state owned company that controls much of the development of Venezuela's resources (EIA 2009).
Brazil holds large offshore oil and natural gas fields which could potentially raise Brazil's profile as they are developed. Brazil's state owned oil company, Petrobas, remains the dominant player despite efforts to open up the market (EIA 2008).
Venezuela's costs are significantly lower and its resources potential is on par with Alberta. Venezuela is much less conducive to business in terms of social and political factors. However, low costs and geological potential may be significant enough to off set social and political risks.
Brazil's relatively high exploration and development costs may be due to the offshore nature of its reserves. While Brazil may boast some important finds, the majority of Brazil's oil resources are found in very deep water and consists of mostly heavy grades, which require further upgrading and processing (EIA 2008).</td></tr>
<tr><td>Brazil</td><td>Royalty/Tax</td><td>↓</td><td>↓</td><td>↓</td></tr>
</table>

Middle East[10]

<table>
<tr><th></th><th>Type of Fiscal System</th><th>Govt. Take</th><th>Cost</th><th>Business Climate</th><th>Discussion & Analysis</th></tr>
<tr><td>Saudi Arabia.</td><td>Service Agreement</td><td>↑↑</td><td>↓↓</td><td>NR</td><td rowspan="4">• Government take in the Middle East falls in the high 80% - 90% range, which appears to be due to its low cost environment. Furthermore, it boasts high quality, abundance, and geological certainty.
• The business environment is generally positive, but there are gaps in terms of information. While this might represent a more socially or politically risky environment, it could also be off set from the developer view by the low geological risk and high resource quality and could be more than sufficient to compensate for qualitative social and political risk.
• As such, North America and the Middle East are not comparable in terms product type, cost, capital, or geology. The Middle East's natural advantage in these areas permit a much higher level of government take that North America would have difficulty sustaining this level of take given the cost structure of oil sands and/or the productivity of conventional sources.</td></tr>
<tr><td>Iran</td><td>Service Agreement</td><td>↑↑</td><td>↓↓</td><td>↓</td></tr>
<tr><td>UAE</td><td>Royalty</td><td>↑↑</td><td>↓↓</td><td>⤓⤒</td></tr>
<tr><td>Kuwait</td><td>Service Agreement</td><td>↑↑</td><td>↓↓</td><td>⤓⤒</td></tr>
</table>

[10] First, there are a data problems associated with benchmarking each individual country in the Middle East. Cost information was available for all countries. Government take figures were only available for Iran and the United Arab Emirates. Policy indicators were only available for Kuwait and the United Arab Emirates. Finally, due to the war, information concerning Iraq is questionable.

Africa

	Type of Fiscal System	Govt. Take	Cost	Business Climate	Discussion & Analysis
Algeria	Production Sharing Contract	↑	↓	↓	• Algeria currently holds 12.3 B/bbl of oil and 161.7 Tcf of natural gas. Algeria's national energy company, Sonatrach, is a major player in the oil and gas industry. Algeria, has proven to be less volatile socially and politically than some of its neighbors.
Angola	Production Sharing Contract	↓	⤓⤒	⇊	• Angola currently holds 8.0 B/bbl of oil and 9.5Tcf of natural gas. Angolan resources are managed by Angola's national oil and gas company, Sonangol. The majority of both Angola's oil and natural gas reserves are found in its offshore / deepwater fields (EIA 2008). Angola has suffered social and political unrest, including civil war and separatist unrest (as reflected in it's the much lower EFI score).
Nigeria	Production Sharing Contract & Retail/Tax	↓	↓	↓	• Nigeria currently holds 36.2 B/bbl of oil and 182 Tcf of natural gas (EIA 2007). Nigerian resources are managed by the Nigerian National Petroleum Company and developed through joint ventures with the major international developers. Two-thirds of oil reserves are found onshore while one-third is found offshore. Nigeria has also seen much political unrest with several militant groups conducting attacks, kidnappings and other acts of violence.

Asia

	Type of Fiscal System	Govt. Take	Cost	Business Climate	Discussion & Analysis
China	Production Sharing Contract	↑	↓↑	↓	• China holds18.3 B/bbl of oil and 53.3 Tcf of natural gas. Around 85% of Chinese oil fields are located onshore. The vast majority of which is developed by Chinese national energy companies. China's offshore potential has been the major focus of international developers where some estimates of China's major offshore fields holding a potential 1.5B/bbl of oil. Furthermore, recent efforts have re-focused efforts towards deepwater exploration in the South China Sea potentially increasing reserves (EIA 2006). • Kazakhstan's combined onshore and offshore proven hydrocarbon reserves have been estimated between 9 and 40 B/bbl. Kazakhstan is home to potentially some of the largest newly discovered outside the Middle East (EIA 2008). Kazakhstan also has a relatively stable social and political climate in relation to some of its regional peers. • Indonesia boasts significant natural gas reserves of which 70% are located offshore (EIA 2007). While exploration costs may be lower, the layout of Indonesia may create a higher cost environment given that it is a country composed of many islands required resources to be shipped over longer distances.
Indonesia	Production Sharing Contract	↑	↓↑	↓	
Kazakhstan	Production Sharing Contract & Retail/Tax	↑↑	↓	↓	

Europe

	Type of Fiscal System	Govt. Take	Cost	Business Climate	Discussion & Analysis
Norway	Retail/Tax	↑↑	↑	↓↑	• Norway currently has reserves of approximately 7.8 B/bbl of oil and 88.3 Tcf of natural gas. Norway is generally a high cost jurisdiction, largely the result of accessibility, weather, and stringent environmental and health /safety issues. Resource extraction is primarily managed by Statoil Hydro, which the government of Norway owns 66.67% share (Statoil Hyrdro 2007). Furthermore, many of Norway's current fields are believed to have peaked prompting some developers to shift explorations elsewhere (EIA 2006).
Russia	Production Sharing Contract	↑	↓↑	↓	• Russia has oil reserves of 60 billion barrels, most of which are located in Western Siberia. Russia holds the world's largest natural gas reserves of approximately 1,680 trillion cubic feet (Tcf), which is nearly twice the size of the next largest country, Iran (EIA 2008). Overall, Russia is socially and politically more unstable compared to its counterparts due to persistent social, political and economic turmoil. The Russian energy industry is dominated by major state owned players including Gazprom and Rosneft in which the Russian government owns 50.01% (Gazprom 2009) and 75% (Rosneft 2009) respectively.

8.2 Provincial Comparison

The scope of this analysis has focused in large part on international comparisons. However, monitoring royalty systems within the provinces of Canada is important as they may influence how Alberta balances the trade-offs between development (and its associated benefits) and government take. Understanding other provincial royalty polices and incentive programs may provide an indication of their approach to balancing various objectives.

The following table highlights Alberta's resource potential relative to other Canadian jurisdictions. Alberta's potential far outweighs any other jurisdictions in Canada particularly with respect to proven oil sands reserves. This concentration of energy resources influences the utility of comparative analysis. However, Saskatchewan and BC are certainly the most comparable and based on proximity are likely to have the greatest influence on Alberta particularly with regard to conventional oil and natural gas (see Table 3).

Table 3 – Total Canadian Reserves (CAPP Stat. Handbook, 2009)

Alberta				British Columbia			
Bitumen	Crude Oil	Heavy Oil	Natural Gas	Bitumen	Crude Oil	Heavy Oil	Natural Gas
786,590	185,283	73,262	1,124,930	0	17,129	0	375,929
Eastern Canada				**Manitoba**			
Bitumen	Crude Oil	Heavy Oil	Natural Gas	Bitumen	Crude Oil	Heavy Oil	Natural Gas
0	0	0	105	0	7,046	0	0
Ontario				**Saskatchewan**			
Bitumen	Crude Oil	Heavy Oil	Natural Gas	Bitumen	Crude Oil	Heavy Oil	Natural Gas
0	1,620	00	19,842	0	103,138	87,351	95,060

Table 4 below identifies the various types of incentive programs offered in Saskatchewan, Alberta and BC. Ongoing monitoring and analysis of each of these programs and their impact on industry activities is important to understand the potential impact on Alberta's objectives. See Appendix F.

Table 4: Provincial Royalty Program Comparison[11]

	Conventional Oil Incentive	Natural Gas (Deep) Incentive	Research and Development	Enhanced Recovery Programs	Carbon Capture Incentive
Alberta	No	Yes	Yes	Yes	Yes
BC	Yes	Yes	No	Yes	Yes
Saskatchewan	Yes	No	Yes	Yes	Yes

[11] See Appendix I for royalty program citations.

9 Evaluation of the Crown Revenue Share Performance Measure

This report has stressed that one of the key challenges of royalty system is to balance the objectives of return to owners and development. The challenge is reflected in the first goal in the Ministry of Energy's 2009-13 Business Plan, which states: *Alberta has a competitive and effective royalty system, incenting development and maximizing benefits to Albertans*[12]. The first part of this goal (competitive and effective royalty system) focuses on development while the second part (maximizing benefits) addresses return to owners.

Performance under this goal is measured by examining the share of industry revenues the Government collects through royalties. This performance measure, which is currently under review, has limited utility as it does not:

- Align with the goals of sharing in the benefits since it does not factor in other forms of revenue received by the Government, such as taxes and bonus fees.
- Align with the goals of development since companies consider total government take (not just royalty payments) when making their investment decisions.
- Consider other factors (e.g. geology, costs and risks) that influence the level of revenue the government collects.

The specific target for this measure is 20-25% of industry net revenues to be collected through the royalty system. The Valentine Report recommended that Alberta Energy review the continued appropriateness of the 20%-25% target range for the Government's share of industry revenue (Valentine, 2008). The use of an explicit target range is problematic for the following reasons:

- The royalty share should evolve over-time based on changing market (e.g. prices) or risk factors and geological conditions. For example, a growing share of production in Alberta comes from the oil sands, which are generally more costly to extract. Under a higher cost environment, Alberta may not be able to collect 20-25% revenues and still remain competitive.
- The royalty system must be responsive to global competition. The Government may need to periodically alter royalty rates and incentives to ensure Alberta remains a globally competitive location for investment. These adjustments, while necessary, may cause the share of industry revenues collected through the royalty system to deviate from the 20-25% target.

The current "share of revenue" measure is an incomplete and perhaps inadequate indicator of both the benefits accruing to Albertans from resource development and competitiveness. Moreover, the target range does not account for changes in market, risk or geological factors. To the extent possible, total government take as a share of industry profits may be considered to be a better replacement for the current measure. This measure should not be given a target range, but rather compared to other jurisdictions in the context of other indicators of competitiveness.

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[12] Alberta Ministry of Energy, *Business Plan 2009-12*, submitted March 20, 2009. The Ministry of Energy consists of the Department of Energy, the Energy Resources Conservation Board (ERCB) and the Alberta Utilities Commission (AUC).

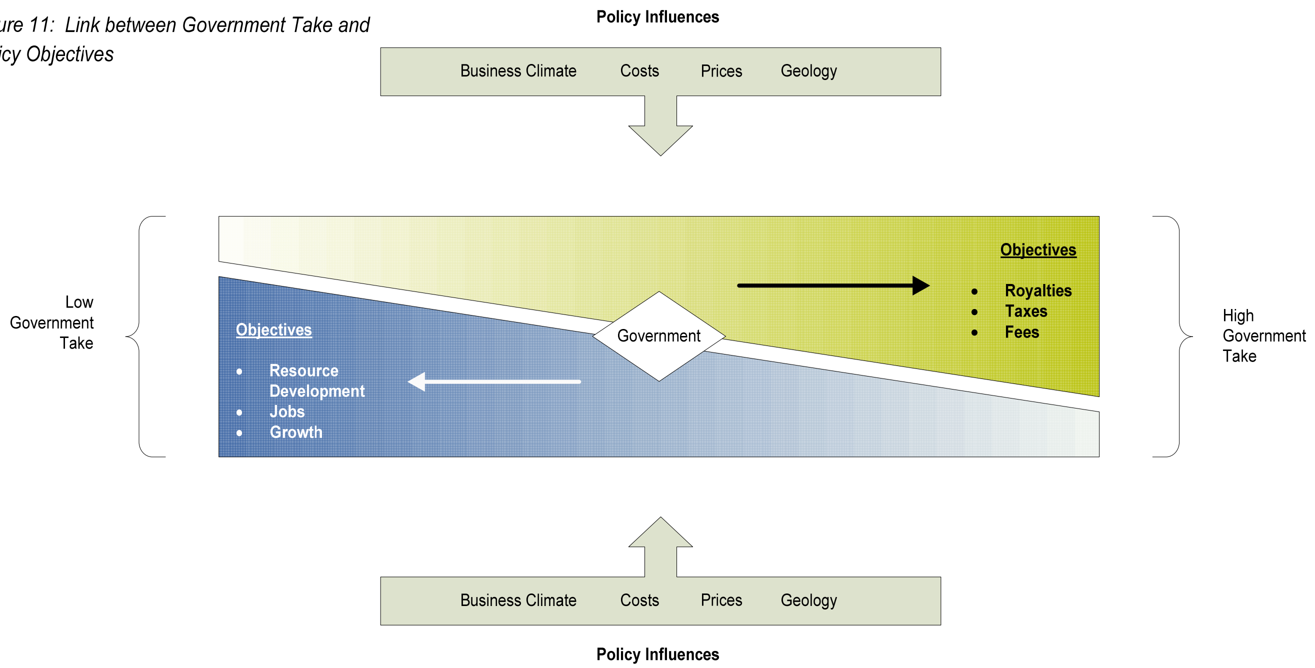
10 Summary

The combination of all royalties, fees and taxes paid by the private developer to the government is called total "government take". It is government take – not only royalties or taxes paid - that matters from a public policy perspective.

Royalty systems, namely the level of government take, endeavor to strike balance two, and at times, competing objectives: returning a share of the profits to the resource owner and encouraging the development of the resource. Resource owners that favor an accelerated pace of development may opt for a system that captures a relatively low government take, leaving more income in the hands of the developer. On the other hand, owners may wish to receive a high financial return at the expense of less development. See Figure 11.

Many factors influence what level of government take is required to meet these objectives. For example, if resources are difficult or costly to extract, a low level of government take may be required to achieve the desired level of development. Alternatively, if a jurisdiction's business climate is favorable due to low levels of political and regulatory risk, then a jurisdiction may be able to achieve the desired level of development with a relatively high government take.

Figure 11: Link between Government Take and Policy Objectives



There are limits to how much government take can be raised. With globalization and the opening of new markets, investment by large oil and gas companies now moves freely around the world in search of the highest return. If government take is set too high, Alberta's resources may remain underdeveloped.

Determining what level of government take is appropriate typically employs a comparison to other resource producing jurisdictions. However, these comparisons are not precise. Indeed, comparisons to Alberta, particularly at the international level, are difficult to make because of the unique nature of Alberta's resources and the specific environment in which private developers operate. A *direct* comparison of Alberta's level of government take to other jurisdictions could lead to inaccurate conclusions regarding Alberta's royalty system and the policy context upon which it is based.

This is not to suggest that comparisons should not be made. It is imperative that the government continually monitor other jurisdictions to ensure that the royalty system is meeting the intended objectives. However, royalty policy should consider the context of several factors that also influence the balance between development and return to owners.

This report introduced a framework for comparing Alberta's government take to other jurisdictions. In particular, government take was examined in the context of several factors, including type of resource, costs, protection of property rights, legal enforcement of contracts, capital market controls, business regulations, and political risk. This framework offers the following advantages:

- Highlights areas of relative jurisdictional strengths and weaknesses;
- Helps facilitate understanding and communicate the complexity of royalty decisions to resource owners; and
- Guides royalty policy discussion and debate.

For Alberta's royalty system, the challenge of balancing of return to owners and development is addressed in the first goal in the Ministry of Energy's 2009-13 Business plan, which states: *Alberta has a competitive and effective royalty system, incenting development and maximizing benefits to Albertans.* Based on our analysis, Alberta Energy's current performance measure for this goal - the share of industry revenues collected by royalty system – has limited utility for the following reason. First, it ignores other forms of revenue received by the government (e.g. bonus fees, taxes). Second, it does not adequately measure against the objectives of development and return in a highly competitive environment. Third, the use of a 20-25% target for royalty collection as a share of industry revenue does not account for the dynamic nature of the royalty regime, particularly the need to respond to changing geological conditions and costs and the evolving competitive environment.

In terms of the jurisdictional comparisons, government take is useful because it is the one element (unlike differences in geology, politics, business climate, etc.) that is common to all jurisdictions and considers all payments made by energy companies to the government. However, it should not be viewed in isolation. Rather, government take in the larger context of the jurisdiction and resource in question can serve as an indicator for further study and review. The scope of this review has focused in large part on international comparisons. However, monitoring royalty systems within the provinces of Canada is important as they may influence how Alberta balances the trade-offs between development (and its associated benefits) and government take. Understanding other provincial royalty polices and incentive programs may provide an indication of their approach to balancing various objectives.

Appendix A: Summary of Conventional Oil and Natural Gas Reserves

The following information is extracted from the BP Statistical Review of World Energy 2008. This information is used to identify countries with significant oil and natural gas reserves for comparison to Alberta. Note that in developing the percentage summary Table A below, Russia is included as part of Europe and Kazakhstan is included are part of Asia.

Table A

Jurisdiction	Oil	Natural Gas
North America	5.60%	4.50%
South America	9.00%	4.40%
Europe	8.40%	32.60%
Middle East	61.00%	41.30%
Asia	6.50%	9.30%
Africa	9.50%	8.20%
World	100.00%	*100.00%

- *May not add to 100% due to rounding.

Oil

Proved reserves	At end 1987 Thousand million barrels	At end 1997 Thousand million barrels	At end 2006 Thousand million barrels	At end 2007 Thousand million tonnes	At end 2007 Thousand million barrels	Share of total	R/P ratio
US	35.4	30.5	29.4	3.6	29.4	2.4%	11.7
Canada	11.7	10.7	27.7	4.2	27.7	2.2%	22.9
Mexico	54.1	47.8	12.8	1.7	12.2	1.0%	9.6
Total North America	**101.2**	**89.0**	**70.0**	**9.5**	**69.3**	**5.6%**	**13.9**
Argentina	2.2	2.6	2.6	0.4	2.6	0.2%	10.2
Brazil	2.6	7.1	12.2	1.7	12.6	1.0%	18.9
Colombia	1.9	2.6	1.5	0.2	1.5	0.1%	7.4
Ecuador	1.6	3.7	4.5	0.6	4.3	0.3%	22.5
Peru	0.5	0.8	1.1	0.1	1.1	0.1%	26.4
Trinidad & Tobago	0.6	0.7	0.8	0.1	0.8	0.1%	14.1
Venezuela	58.1	74.9	87.0	12.5	87.0	7.0%	91.3
Other S. & Cent. America	0.6	1.1	1.3	0.2	1.3	0.1%	25.2
Total S. & Cent. America	**68.1**	**93.4**	**111.0**	**15.9**	**111.2**	**9.0%**	**45.9**
Azerbaijan	n/a	n/a	7.0	1.0	7.0	0.6%	22.1
Denmark	0.4	0.9	1.2	0.1	1.1	0.1%	9.8
Italy	0.7	0.8	0.8	0.1	0.8	0.1%	17.6
Kazakhstan	n/a	n/a	39.8	5.3	39.8	3.2%	73.2
Norway	6.6	12.0	8.5	1.0	8.2	0.7%	8.8
Romania	1.3	0.9	0.5	0.1	0.5	♦	12.4
Russian Federation	n/a	n/a	79.3	10.9	79.4	6.4%	21.8
Turkmenistan	n/a	n/a	0.6	0.1	0.6	♦	8.3
United Kingdom	5.2	5.2	3.6	0.5	3.6	0.3%	6.0
Uzbekistan	n/a	n/a	0.6	0.1	0.6	♦	14.3
Other Europe & Eurasia	61.7	68.0	2.2	0.3	2.1	0.2%	12.8
Total Europe & Eurasia	**75.8**	**88.0**	**144.1**	**19.4**	**143.7**	**11.6%**	**22.1**
Iran	92.9	92.6	138.4	19.0	138.4	11.2%	86.2
Iraq	100.0	112.5	115.0	15.5	115.0	9.3%	*
Kuwait	94.5	96.5	101.5	14.0	101.5	8.2%	*
Oman	4.1	5.4	5.6	0.8	5.6	0.5%	21.3
Qatar	4.5	12.5	27.9	3.6	27.4	2.2%	62.8
Saudi Arabia	169.6	261.5	264.3	36.3	264.2	21.3%	69.5
Syria	1.7	2.3	3.0	0.3	2.5	0.2%	17.4
United Arab Emirates	98.1	97.8	97.8	13.0	97.8	7.9%	91.9
Yemen	1.1	1.8	2.8	0.4	2.8	0.2%	22.7
Other Middle East	0.1	0.2	0.1	†	0.1	♦	10.9
Total Middle East	**566.6**	**683.2**	**756.3**	**102.9**	**755.3**	**61.0%**	**82.2**
Algeria	8.6	11.2	12.3	1.5	12.3	1.0%	16.8
Angola	2.0	3.9	9.0	1.2	9.0	0.7%	14.4
Chad	–	–	0.9	0.1	0.9	0.1%	17.2
Republic of Congo (Brazzaville)	0.7	1.6	1.9	0.3	1.9	0.2%	23.9
Egypt	4.7	3.7	3.7	0.5	4.1	0.3%	15.7
Equatorial Guinea	–	0.6	1.8	0.2	1.8	0.1%	13.2
Gabon	1.0	2.7	2.0	0.3	2.0	0.2%	23.8
Libya	22.8	29.5	41.5	5.4	41.5	3.3%	61.5
Nigeria	16.0	20.8	36.2	4.9	36.2	2.9%	42.1
Sudan	0.3	0.3	6.6	0.9	6.6	0.5%	39.7
Tunisia	1.7	0.3	0.6	0.1	0.6	♦	16.7
Other Africa	1.0	0.7	0.6	0.1	0.6	0.1%	10.2
Total Africa	**58.7**	**75.3**	**117.1**	**15.6**	**117.5**	**9.5%**	**31.2**
Australia	3.2	4.0	4.2	0.4	4.2	0.3%	20.3
Brunei	1.6	1.1	1.2	0.2	1.2	0.1%	16.9
China	17.4	17.0	15.6	2.1	15.5	1.3%	11.3
India	4.4	5.6	5.7	0.7	5.5	0.4%	18.7
Indonesia	9.0	4.9	4.4	0.6	4.4	0.4%	12.4
Malaysia	3.3	5.0	5.4	0.7	5.4	0.4%	19.4
Thailand	0.1	0.3	0.5	0.1	0.5	♦	4.1
Vietnam	†	1.2	3.3	0.5	3.4	0.3%	27.5
Other Asia Pacific	0.8	1.2	0.9	0.1	0.9	0.1%	11.0
Total Asia Pacific	**39.8**	**40.4**	**41.0**	**5.4**	**40.8**	**3.3%**	**14.2**
TOTAL WORLD	**910.2**	**1069.3**	**1239.5**	**168.6**	**1237.9**	**100.0%**	**41.6**

VL > 200 M/bbl, L 150 – 200 M/bbl, M 100M/bbl – 150M/bbl, S > 50M/bbl <100M/bbl, VS 0 - 50M/bbl

Natural gas

Proved reserves	At end 1987 Trillion cubic metres	At end 1997 Trillion cubic metres	At end 2006 Trillion cubic metres	At end 2007 Trillion cubic feet	At end 2007 Trillion cubic metres	At end 2007 Share of total	At end 2007 R/P ratio
US	5.30	4.74	5.98	211.08	5.98	3.4%	10.9
Canada	2.69	1.81	1.62	57.55	1.63	0.9%	8.9
Mexico	2.12	1.80	0.39	13.01	0.37	0.2%	8.0
Total North America	**10.11**	**8.34**	**7.99**	**281.65**	**7.98**	**4.5%**	**10.3**
Argentina	0.69	0.68	0.45	15.54	0.44	0.2%	9.8
Bolivia	0.14	0.12	0.74	26.13	0.74	0.4%	54.7
Brazil	0.11	0.23	0.35	12.89	0.36	0.2%	32.3
Colombia	0.10	0.20	0.12	4.41	0.13	0.1%	16.2
Peru	0.34	0.20	0.33	12.54	0.36	0.2%	*
Trinidad & Tobago	0.30	0.52	0.48	16.95	0.48	0.3%	12.3
Venezuela	2.84	4.12	5.10	181.87	5.15	2.9%	*
Other S. & Cent. America	0.15	0.15	0.07	2.51	0.07	♦	21.0
Total S. & Cent. America	**4.67**	**6.21**	**7.64**	**272.84**	**7.73**	**4.4%**	**51.2**
Azerbaijan	n/a	0.84	1.26	45.13	1.28	0.7%	*
Denmark	0.07	0.11	0.12	4.10	0.12	0.1%	12.6
Germany	0.38	0.26	0.16	4.84	0.14	0.1%	9.6
Italy	0.30	0.27	0.09	3.14	0.09	0.1%	10.0
Kazakhstan	n/a	1.87	1.90	67.20	1.90	1.1%	69.8
Netherlands	1.77	1.79	1.32	44.07	1.25	0.7%	19.4
Norway	2.29	3.65	2.89	104.57	2.96	1.7%	33.0
Poland	0.16	0.16	0.11	3.99	0.11	0.1%	26.4
Romania	0.20	0.37	0.63	22.18	0.63	0.4%	54.4
Russian Federation	n/a	45.17	44.60	1576.75	44.65	25.2%	73.5
Turkmenistan	n/a	2.71	2.67	94.22	2.67	1.5%	39.6
Ukraine	n/a	0.98	1.03	36.24	1.03	0.6%	54.0
United Kingdom	0.64	0.77	0.41	14.55	0.41	0.2%	5.7
Uzbekistan	n/a	1.63	1.74	61.60	1.74	1.0%	29.8
Other Europe & Eurasia	39.25	0.45	0.44	15.31	0.43	0.2%	39.4
Total Europe & Eurasia	**45.06**	**61.02**	**59.37**	**2097.89**	**59.41**	**33.5%**	**55.2**
Bahrain	0.20	0.14	0.09	3.00	0.09	♦	7.4
Iran	13.92	23.00	27.58	981.75	27.80	15.7%	*
Iraq	1.00	3.19	3.17	111.95	3.17	1.8%	*
Kuwait	1.21	1.49	1.78	63.00	1.78	1.0%	*
Oman	0.27	0.54	0.69	24.37	0.69	0.4%	28.6
Qatar	4.44	8.50	25.64	904.06	25.60	14.4%	*
Saudi Arabia	4.19	5.88	7.07	253.03	7.17	4.0%	94.4
Syria	0.13	0.24	0.29	10.17	0.29	0.2%	54.7
United Arab Emirates	5.68	6.06	6.11	215.07	6.09	3.4%	*
Yemen	0.11	0.48	0.49	17.23	0.49	0.3%	*
Other Middle East	†	†	0.05	1.73	0.05	♦	18.5
Total Middle East	**31.18**	**49.53**	**72.95**	**2585.35**	**73.21**	**41.3%**	*****
Algeria	3.16	4.08	4.50	159.45	4.52	2.5%	54.4
Egypt	0.31	0.93	2.05	72.85	2.06	1.2%	44.3
Libya	0.73	1.31	1.49	52.80	1.50	0.8%	98.4
Nigeria	2.41	3.48	5.22	186.99	5.30	3.0%	*
Other Africa	0.79	0.82	1.20	42.84	1.21	0.7%	*
Total Africa	**7.39**	**10.62**	**14.46**	**514.92**	**14.58**	**8.2%**	**76.6**
Australia	1.07	1.48	2.49	88.64	2.51	1.4%	62.8
Bangladesh	0.35	0.30	0.39	13.77	0.39	0.2%	24.0
Brunei	0.33	0.39	0.33	12.11	0.34	0.2%	28.0
China	0.89	1.16	1.68	66.54	1.88	1.1%	27.2
India	0.55	0.69	1.08	37.26	1.06	0.6%	35.0
Indonesia	2.37	2.15	2.63	105.94	3.00	1.7%	45.0
Malaysia	1.49	2.46	2.48	87.40	2.48	1.4%	40.9
Myanmar	0.27	0.28	0.54	21.19	0.60	0.3%	40.8
Pakistan	0.63	0.60	0.85	30.02	0.85	0.5%	27.6
Papua New Guinea	0.09	0.43	0.44	15.36	0.44	0.2%	*
Thailand	0.18	0.21	0.33	11.65	0.33	0.2%	12.7
Vietnam	†	0.17	0.22	7.77	0.22	0.1%	28.5
Other Asia Pacific	0.23	0.41	0.37	13.02	0.37	0.2%	21.9
Total Asia Pacific	**8.45**	**10.73**	**13.82**	**510.69**	**14.46**	**8.2%**	**36.9**
TOTAL WORLD	**106.86**	**146.46**	**176.22**	**6263.34**	**177.36**	**100.00%**	**60.3**

VL > 1Qcf, L 1Qcf – 750Tcf, M 500Tcf – 750Tcf, S 250Tcf – 500Tcf, VS 0 – 250Tcf

<table>
<tr><th>Jurisdiction</th><th>Type of Fiscal System</th><th>Govt. Take</th><th>Notable Resources[13]</th><th>Overall Cost Conditions</th><th>Overall Business Conditions[14]</th></tr>
<tr><td>Saudi Arabia</td><td>SA</td><td>NR</td><td>VL-CO / VS-NG / S</td><td rowspan="7">Low</td><td>NR</td></tr>
<tr><td>Kuwait</td><td>SA</td><td>NR</td><td>S-CO / VS-NG / S</td><td>High</td></tr>
<tr><td>Iran</td><td>SA</td><td>~93%</td><td>M-CO / M-NG / S</td><td>Medium</td></tr>
<tr><td>Venezuela</td><td>PSC</td><td>88%-91%</td><td>VL-HO / S-CO / S</td><td>Low</td></tr>
<tr><td>Algeria</td><td>PSC / RT</td><td>~72%</td><td>VS-CO / VS-NG / S</td><td>Medium</td></tr>
<tr><td>UAE</td><td>R</td><td>85%-86%</td><td>S-CO / VS-NG / S</td><td>High</td></tr>
<tr><td>Kazak.</td><td>PSA / RT</td><td>82%-83%</td><td>L-B / S</td><td>Medium</td></tr>
<tr><td>Nigeria</td><td>PSC / RT</td><td>~62%</td><td>VS-CO / VS-NG</td><td rowspan="5">Medium</td><td>Medium</td></tr>
<tr><td>Brazil</td><td>RT</td><td>~60%</td><td>VS-CO / DW</td><td>Medium</td></tr>
<tr><td>China</td><td>PSC</td><td>71%-72%</td><td>VS-CO / VS-NG</td><td>Medium</td></tr>
<tr><td>Russia</td><td>PSC</td><td>69%-72%</td><td>VL-NG / S / OS</td><td>Medium</td></tr>
<tr><td>Iraq[15]</td><td>NR</td><td>NR</td><td>NR</td><td>NR</td></tr>
<tr><td>Angola</td><td>PSC</td><td>60%-64%</td><td>VS-CO / VS-NG / OS</td><td rowspan="6">High</td><td>Low</td></tr>
<tr><td>Indonesia</td><td>PSC</td><td>~71%</td><td>VS-CO / VS-NG / OS</td><td>Low</td></tr>
<tr><td>Canada (Alberta)</td><td>RT</td><td>65%-70%</td><td>VL-B / S</td><td>Very High</td></tr>
<tr><td>Norway</td><td>RT</td><td>82%-83%</td><td>VS-NG / VS-CO / S</td><td>High</td></tr>
<tr><td>US (Fed GoM)</td><td>RT</td><td>35%-41%</td><td>VS-CO / VS-NG / SW / DW</td><td>High</td></tr>
<tr><td>US (State)*[16]</td><td>RT</td><td>52%-59%</td><td>VS-CO / OS</td><td>High</td></tr>
</table>

[13] Size determined through a review of proved reserves. See Appendices B and C for ranking criteria. Nature of the jurisdictions field is not to be a comprehensive ranking. It is meant to provide a sense of the jurisdictions potential for future development.
[14] This measure is derived from taking a simple average of each of the raw scores. While this may, or may not, result in domestic violence or corruption, it can also result in large policy shifts such as conscription or large public borrowing for military programs.
[15] Iraq war is significant enough to call available information into question.
[16] Refer to the range for Texas, Alaska, and Wyoming collectively.

<table>
<tr><th>Jurisdiction</th><th colspan="2">Type of Fiscal System</th><th>Govt. Take</th><th>Notable Resources[13]</th><th>Overall Cost Conditions</th><th>Overall Business Conditions[14]</th></tr>
<tr><td colspan="7">Key</td></tr>
<tr><td>Fiscal System Type</td><td colspan="3">Field Size</td><td>Field Type</td><td>Costs</td><td>EFI Summary Score</td></tr>
<tr><td>SA = Service agreement
PSC = Production sharing contract
RT = Royalty and/or tax
NR = Not reported</td><td>VL = Very Large
L = Large
M= Medium
S = Small
VS = Very Small</td><td>VL > 1Qcf
L 1Qcf – 750Tcf,
M 500Tcf – 750Tcf,
S 250Tcf – 500Tcf
VS 0 – 250Tcf</td><td>VL > 200 M/bbl
L 150 – 200 M/bbl
M 100M/bbl – 150M/bbl,
S > 50M/bbl <100M/bbl
VS 0 - 50M/bbl</td><td>CO = Conventional Oil
HO = Heavy Oil
NB = Natural Bitumen
NG = Natural Gas
DW = Deep water
OS = Offshore
S = Onshore</td><td>L = $3.00 - $4.79
M = $4.80 - $7.99
H = $8.00 - $15.00</td><td>Very low = 0 – 2.0
Low = 2.01 – 4.0
Medium = 4.01 – 6.0
High = 6.01 – 8.0
Very High = 8.01 = 10.0
NR = Not reported</td></tr>
</table>

Appendix B: Summary of Bitumen and Other Heavy Oil Reserves

The following list of world bitumen and other heavy oil reserves are presented to identify countries with significant reserves for comparison to Alberta based data provided by, the World Energy Council (WEC 2007). Note that Russia has been included as part of Europe and Kazakhstan has been included as part of Asia.

Table B

	Bitumen	Extra Heavy Oil
• North America	71.16%	0.32%
• South America	0.00%	95.46%
• Europe	11.39%	1.83%
• Middle East	0.00%	0.00%
• Africa	0.52%	0.07%
• Asia	16.92%	2.32%
• World	*100.00%	*100.00%

*May not add to 100% due to rounding.

Natural Bitumen

Country	Deposits	Original Reserves
• Angola	3	465
• Congo (Brazzaville)	1	6
• Congo (Democratic Rep.)	1	30
• Madagascar	1	221
• Nigeria	1	574
• Total Africa	7	1296
• Canada	227	178580
• Trinidad & Tobago	14	0
• United States of America	201	24
• Total North America	442	178604
• Venezuela	1	
• Total South America	1	
• Azerbaijan	3	1
• China	4	1
• Georgia	1	3
• Indonesia	1	446
• Kazakhstan	52	42009
• Kyrgyzstan	7	0
• Tajikistan	4	0
• Uzbekistan	8	0
• Total Asia	80	42460
• Italy	14	210
• Russian Federation	39	28380
• Switzerland	1	0
• Total Europe	54	28590
• Syria (Arab Rep.)	1	0
• Total Middle East	1	0
• Tonga	1	0
• Total Oceania	1	0
• TOTAL WORLD	586	250950

Other Heavy Oil

Country	Deposits	Original Reserves
• Egypt (Arab Rep.)	1	50
• Total Africa	1	50
• Canada	4	0
• Mexico	2	6
• Trinidad & Tobago	2	0
• United States of America	54	235
• Total North America	62	241
• Colombia	2	38
• Cuba	1	48
• Ecuador	3	92
• Peru	2	25
• Venezuela	33	72556
• Total South America	41	72759
• Azerbaijan	1	884
• China	12	888
• Uzbekistan	1	0
• Total Asia	14	1772
• Albania	2	37
• Germany	1	0
• Italy	31	269
• Poland	2	0
• Russian Federation	6	6
• United Kingdom	2	1085
• Total Europe	44	1397
• Iran (Islamic Rep.)	1	0
• Iraq	1	0
• Israel	2	1
• Total Middle East	4	1
• TOTAL WORLD	166	76220

Appendix C: Energy Costs (Exploration/Production)

For oil and gas costs, a 2005 OPEC study (Al-Attar and Alomir 2005, 250) was reviewed and the following information was extracted to illustrate the cost environment for major conventional oil producing jurisdictions. This information does not provide costs for specific projects. Rather this information represents high level estimates for the region or jurisdiction as a whole. This information offers coverage of major energy producing regions.

Jurisdiction	Exploration	Production	Total	Range
Saudi	$1.50	$1.50	$3.00	Low
Kuwait	$1.75	$1.80	$3.55	
Iran	$1.75	$2.50	$4.25	
Venezuela (extra heavy)	$2.00	$2.50	$4.50	
Algeria	$2.15	$2.50	$4.65	
UAE	$3.00	$1.80	$4.80	
Kazak.	$3.50	$1.30	$4.80	
Nigeria	$3.00	$2.25	$5.25	Medium
Oman	$3.75	$2.50	$6.35	
Brazil	$3.80	$3.20	$7.00	
China	$3.50	$4.00	$7.50	
Russia	$4.25	$3.50	$7.75	
Iraq	-	-	-	
Angola	$5.00	$3.00	$8.00	High
Indonesia	$2.50	$6.00	$8.50	
US Lower 48 (onshore)	$4.95	$3.57	$8.52	
Canada (Western)	$6.75	$3.00	$9.75	
North Sea (Norway)	$7.50	$3.00	$10.50	
Canada (Eastern)	$6.75	$3.00	$11.80	
US GOM	$11.00	$3.50	$14.50	

The following information was extracted from World Energy-Survey of Energy Resource 2007.

	$2005 (US) per barrel at plant gate	
Method	Product	Supply Cost
Cold (Wabasca, Seal)	Bitumen	12-15
Cold(heavy oil w/ sand)	Bitumen	13-16
Cyclic steam (Cold Lake)	Bitumen	17-20
SAGD	Bitumen	17-20
Mining/extraction	Bitumen	15-17
Integrated	Syncrude	30-33

Appendix D: Summary of EFI Ratings

The following information was extracted from the 2008 Economic Freedom Index (Fraser Institute 2008, 42-182). This information provides a basis for assessing business climate in various countries using numerous policies employed in each jurisdiction. This analysis is not intended to be a comprehensive review. While there are numerous measures within the EFI Index, the measures selected for this comparison are intended to reflect policy areas that are in large part within the control of government. PwC derived the average overall score for each jurisdiction. These scores were then subjectively ranked (very low to very high) to facilitate comparisons.

Measure	Canada	US	Russia	Saudi Arabia.	UAE	Iran	Algeria	Angola	Indonesia
2C Protection of property rights	8.47	7.58	3.6	N/R	6.97	NR	5.58	4.11	3.96
2D Military interference in rule of law and the political process (CRG)	10.00	6.67	7.50	N/R	8.33	8.33	5.0	3.33	4.17
2F Legal enforcement of contracts	5.18	7.63	7.53	N/R	4.23	5.5	4.66	2.3	1.17
4E International Capital Market Controls	7.25	6.72	3.90	N/R	6.5	1.54	4.15	3.33	4.92
5C Business Regulations	8.12	7.27	3.93	N/R	7.40	5.24	5.36	3.51	5.16
Overall	**8.02**	**7.58**	**5.90**	**N/R**	**7.11**	**4.11**	**4.95**	**3.32**	**3.88**
Qualitative Rank[17]	**VH**	**H**	**M**	**N/R**	**H**	**M**	**M**	**L**	**L**

[17] Very low = 0 – 2.0, Low = 2.01 – 4.0, Medium = 4.01 – 6.0, High = 6.01 – 8.0, Very High = 8.01 = 10.0, and NR = Not reported

Measure	Venezuela	China	Nigeria	Kazakhstan	Kuwait	Norway	Brazil
2C Protection of property rights	2.15	5.52	4.68	4.97	7.33	8.85	5.77
2D Military interference in rule of law and the political process (CRG)	0.83	5.00	3.33	8.33	8.33	10.00	6.67
2F Legal enforcement of contracts	3.97	6.87	5.08	7.39	5.39	7.53	4.82
4E International Capital Market Controls	4.02	3.20	6.75	3.81	3.81	6.35	5.52
5C Business Regulations	2.89	3.96	3.93	5.49	6.69	3.93	4.20
Overall	**2.77**	**4.91**	**4.75**	**5.99**	**6.47**	**7.33**	**5.40**
Qualitative Rank	**L**	**M**	**M**	**M**	**H**	**H**	**M**

Appendix E: Summary of 'Government Take'

The following is a compilation of government take by jurisdiction. The main challenge in comparing government take across jurisdictions relates to data complexity and/or data availability. Existing studies on government take have limitations insofar as they do not provide information and data (project characteristics and contractual arrangements) in a format that can be efficiently normalized for comparative purposes. The following information was derived from: 2007 US Government Accountability Office study (GAO 2007, 12-15); and 2001 Daniel Johnson study (Johnston 2001, lxv - lxx). The Johnston study was favored over the GAO study based on completeness and level of detail provided. Where information was not available in the Johnston study, information from the GAO study was used.

Jurisdiction	Sample Description / Notes	Type of Fiscal System	Govt. Take (2001 Daniel Johnston Study)	Govt. Take (2007 GAO Study)
Saudi Arabia	No notes provided. No data found.	SA	NR	NR
Kuwait	No notes provided.	SA	NR	NR
Iran	Buyback arrangement	SA		~93%
Venezuela	1996 Risk Service Agreement	RSA	88%-91%	
Algeria	Large onshore operations.	PSC		~72%
UAE (Abu Dhabai)	Concession (aka. OPEC Model)	R	85% - 86%	
Kazak.	Tengiz 1992 (Large offshore field)	PSC	82% - 83%	
Nigeria	1994 Offshore deepwater	PSC	~62%	
Brazil	Offshore deepwater	NR		~60%
China	Offshore deepwater	PSC	71%-72%	
Russia	Sakhalin II (Large offshore)	PSC	69% - 72%	
Angola	1997 Block 16 (Offshore)	PSC		60%-64%
Indonesia	Offshore	PSC		~71%
Canada (Alberta)	No notes provided	RT	65%-70%	
North Sea (Norway)	Late 1990's RT standard agreement (North Sea offshore)	RT	75%-84%	
US (Fed)	Gulf of Mexico (Federal offshore)	RT	48% - 60% (Shall.)	
			35% - 41% (Deep)	

Appendix F: Provincial Government Programs

Alberta (New Royalty Framework, 2008)

Program	Purpose	Description
Innovative Energy Technologies Program (Oil, Gas, & Oil Sands)	The objective of this program is to generate royalties from the increased recovery of oil, gas and oil sands resources which might not otherwise be recovered under present technology.	Successful applicants in the program are provided royalty adjustments, up to a maximum of 30 per cent of approved project costs.
Oil CO_2 Royalty Program	The objective of the CO_2 Projects Royalty Credit Program (the "program") is to encourage projects and application of technology that will lead to the expanded production of Alberta's oil and gas resources through use of CO_2 (Carbon Dioxide) injection into geological formations.	Demonstration projects based in Alberta, which inject a mixture consisting mainly of CO_2 for enhanced recovery of oil, natural gas, or coal bed methane, were eligible for approval under the program.
Drilling Royalty Credit (Temporary)	The incentive program is designed to provide smaller oil and gas companies with temporary assistance as they weather the current global economic downturn.	New well incentive program provides a maximum five-per-cent royalty rate for all new wells that begin producing conventional oil and natural gas between April 1, 2009 and March 31, 2010. A drilling royalty credit will offer $200 in royalty credits per meter drilled on new conventional oil and natural gas wells. Maximum benefits will be provided to smaller oil and gas companies. Finally, the province will invest $30 million in the reclamation and abandonment of old oil and gas well sites.

British Columbia (BC Energy, Mines and Petroleum, 2009)

<table>
<tr><th>Program</th><th>Purpose</th><th>Description</th></tr>
<tr><td>Royalty Credits for Infrastructure Development</td><td>The purposes of the program are to facilitate increased oil and gas exploration and production in under-developed areas and extend the drilling season to allow for year-round activity.</td><td>The Infrastructure Royalty Credit Program allows oil and gas companies to apply for a credit to the royalties they would otherwise pay to the Province. This credit can be as much as 50 per cent of the cost of constructing roads, pipelines or associated facilities.</td></tr>
<tr><td>Coal Bed Gas Program</td><td>The CBG program facilitates the development of provincial CBG resources, while providing a reasonable return to natural gas producers and the Crown.</td><td>The program provides:
• A producer cost of service allowance to address the added water management costs;
• A royalty bank to collect excess allowance to be used against future-assessed CBG royalties;
• Increases the marginal well adjustment factor to address the lower production rates; and
• A $50,000 royalty credit for CBG wells.</td></tr>
<tr><td>Deep Discovery Royalty Program</td><td>The Deep Discovery Royalty Program aims to provide a break from royalties to companies drilling deep discovery wells.</td><td rowspan="3">Credits are calculated automatically as part of royalty remittances.</td></tr>
<tr><td>Deep Re-Entry Program</td><td>This program provides royalty credits to companies when they drill deep re-entry wells. The royalty credits cover a portion of the drilling and completion costs for these wells.</td></tr>
<tr><td>Marginal Royalty Program</td><td>The Marginal Royalty Program is intended to increase the development of gas reserves with low rates of production. It provides lower rates for low productivity natural gas wells.</td></tr>
<tr><td>Net Profit Royalty Program</td><td>Net Profit Royalty Program intends to stimulate development of natural gas and oil resources by sharing the capital risk of successful developments and recognizing the long-lead times associated with these developments.</td><td>The Department issues a Request for Applications (RFA) from interested parties regarding projects that may be eligible for the program and decides on a project by project basis those which qualify. The Ministry's first request targets only projects which are Enhanced Oil/Gas Recovery or Shale Gas in the Horn River Basin.</td></tr>
</table>

Program	Purpose	Description
Summer Drilling Credit Program	Aims to off set costs attributable to individual wells.	The Summer Drilling Credit Program provides a royalty credit equal to 10% of the goods and service costs attributable to the individual wells. The credit will be added to a royalty bank to a maximum of $100,000.
Ultra-Marginal Royalty Program	The Ultra-Marginal Royalty Program offsets costs with low productivity wells where well returns decline after initial drilling and production.	This program is intended to increase the development of shallow gas wells with low rates of production. Compared to the Marginal Royalty Program, the conditions for a well to qualify for the ultra-marginal reduction are more stringent.

Saskatchewan

Program	Purpose	Description
Drilling Incentives	The purpose is to provide royalty breaks to industry to encourage the development of Saskatchewan's energy resources.	Newly drilled oil wells in Saskatchewan qualify for "volume based" drilling incentives ranging. Qualifying incentive volumes are subject to a maximum royalty rate of 2.5% for Crown production. Newly drilled exploratory gas wells in Saskatchewan qualify for a "volume based" drilling incentive. The qualifying incentive volume is subject to a maximum royalty rate of 2.5% for Crown production.
Saskatchewan Petroleum Research Incentive (SPRI)	SPRI is intended to encourage research, development and demonstration of new technologies that facilitate the expanded production of Saskatchewan's oil and natural gas resources.	Credits towards the remission of royalties and taxes are provided to industry and calculated as follows: • 50% of eligible research costs directly involving the Petroleum Technology Research Centre in Regina (to a maximum of $1 million per project), and • 30% of any remaining costs directly involving the PTRC and all other eligible research costs (to a maximum of $3 million per project)
Saskatchewan Carbon Dioxide EOR and Storage Initiative	Provides funding toward the replication of profitable EOR investments at other oilfields on a project by project basis.	See purpose.
The Saskatchewan Oil and Gas Industry Upstream Emission Reduction Initiative	Upstream Emission Reduction Initiative will assist industry in developing technological opportunities to reduce GHG emissions.	The Upstream Emission Reduction Initiative contributes $300,000 to support one or two large projects in Saskatchewan per year with industry. In addition, Saskatchewan also provides up to an additional $100,000 per year as the provincial contribution to smaller oil and gas industry emission reductions projects.

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