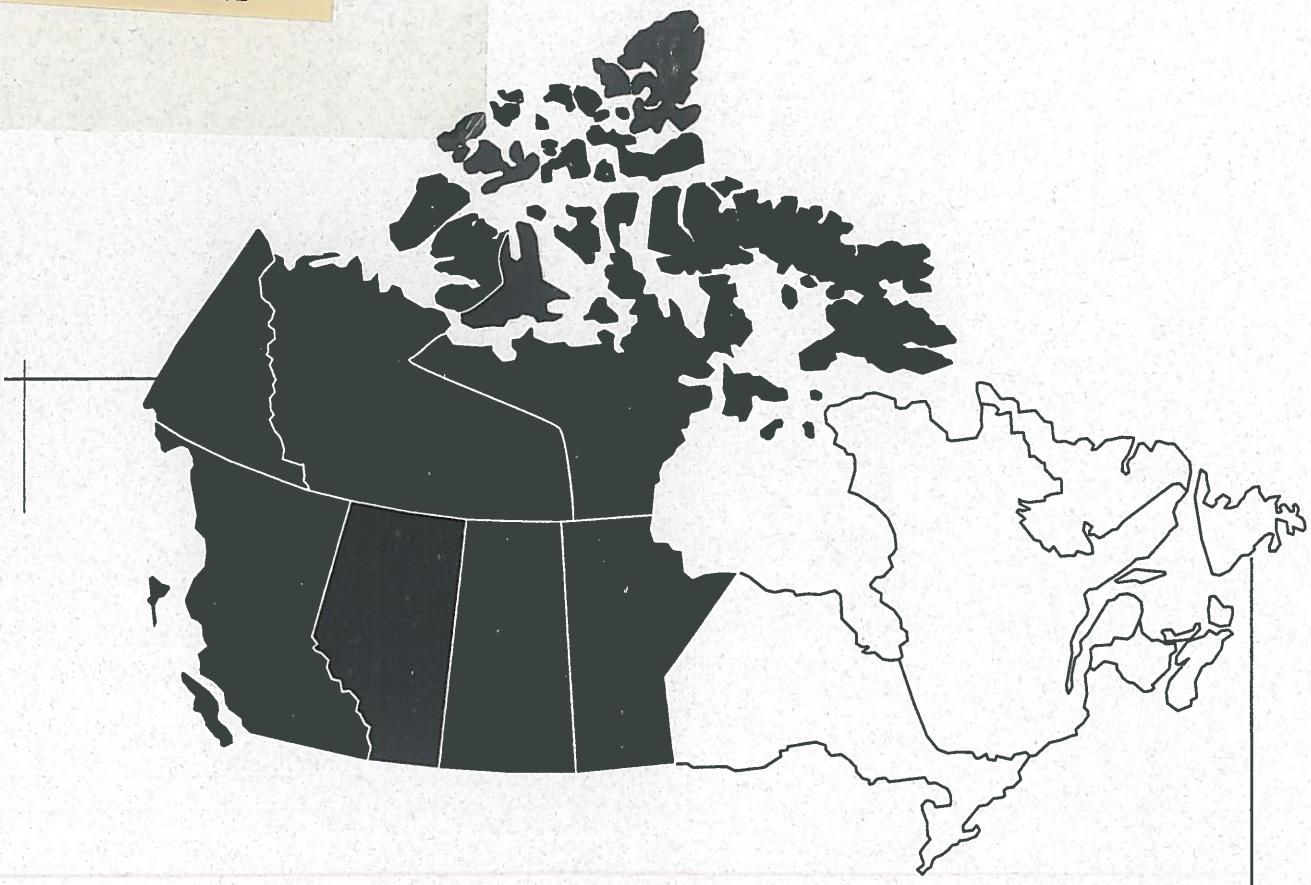

Oil and Gas Fiscal Regimes

of the Western

Canadian Provinces

and Territories

Alberta
RESOURCE DEVELOPMENT

Oil and Gas Fiscal Regimes of the Western Canadian Provinces and Territories

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For additional information on the contents of this report, refer to the list at the end of this report.

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Preface

This report is a summary of the Western Provinces and Territories, fiscal regimes for crude oil, natural gas and natural gas by-products. While all have similar systems of royalty for petroleum resources, there are some distinct differences. The differences in the regimes reflect the unique circumstances in each province, particularly the characteristics of the resource base.

Saskatchewan, British Columbia and Manitoba have each announced significant changes to their fiscal regimes since 1997. Yukon and Nunavut are expected to enact new legislation in the spring of 1999. This report has been updated to reflect the changes where details are available.

Note: The information provided here is for comparative and ease of reference purposes only. Current legislation and reporting guidelines for specific features of each of these regimes should be obtained from the contacts listed at the end of this report.

Introduction

In Alberta, almost all of the petroleum and other mineral rights are owned by the province in the name of the Crown and are administered by Alberta Resource Development. In 1992 a series of policy changes regarding royalties on oil and natural gas were announced. These were the most sweeping changes since 1974. The new policies reflect the increasing maturity of the western Canadian sedimentary basin with respect to oil exploration, and the dramatically different world market conditions as compared with 1974 when expectations were that oil prices would be high for the long term. In 1995, expected prices were around $20US per barrel of light crude oil. The average price in 1998 was considerably lower.

Alberta's policies reflect its continuing philosophy with respect to resource development. The development of the Province's natural endowment of petroleum resources should take place in such a way as to ensure a fair financial return to the province as owner of the resources and to maximise other benefits of resource development to the province. The Province believes this can best be accomplished through private enterprise resource development in a free market economy, with a minimum of government intervention, and by maintaining a stable and predictable fiscal regime for exploration.

In Alberta, resource development proceeds through a business arrangement between the Province as resource owner, and the private companies that explore and develop the resource. This arrangement benefits both partners. The Province provides companies with the right to exploit the resource. Industry provides the knowledge, ability, and capital needed to explore, develop and extract the resource, and deliver it to market. The province and the companies share in the oil and gas production or its revenue. The return to industry must be sufficient to cover costs and give investors a reasonable rate of return. The share retained by the province is specified by the fiscal regime. The province's royalty share is part of the price companies pay for the right to exploit the natural resource.

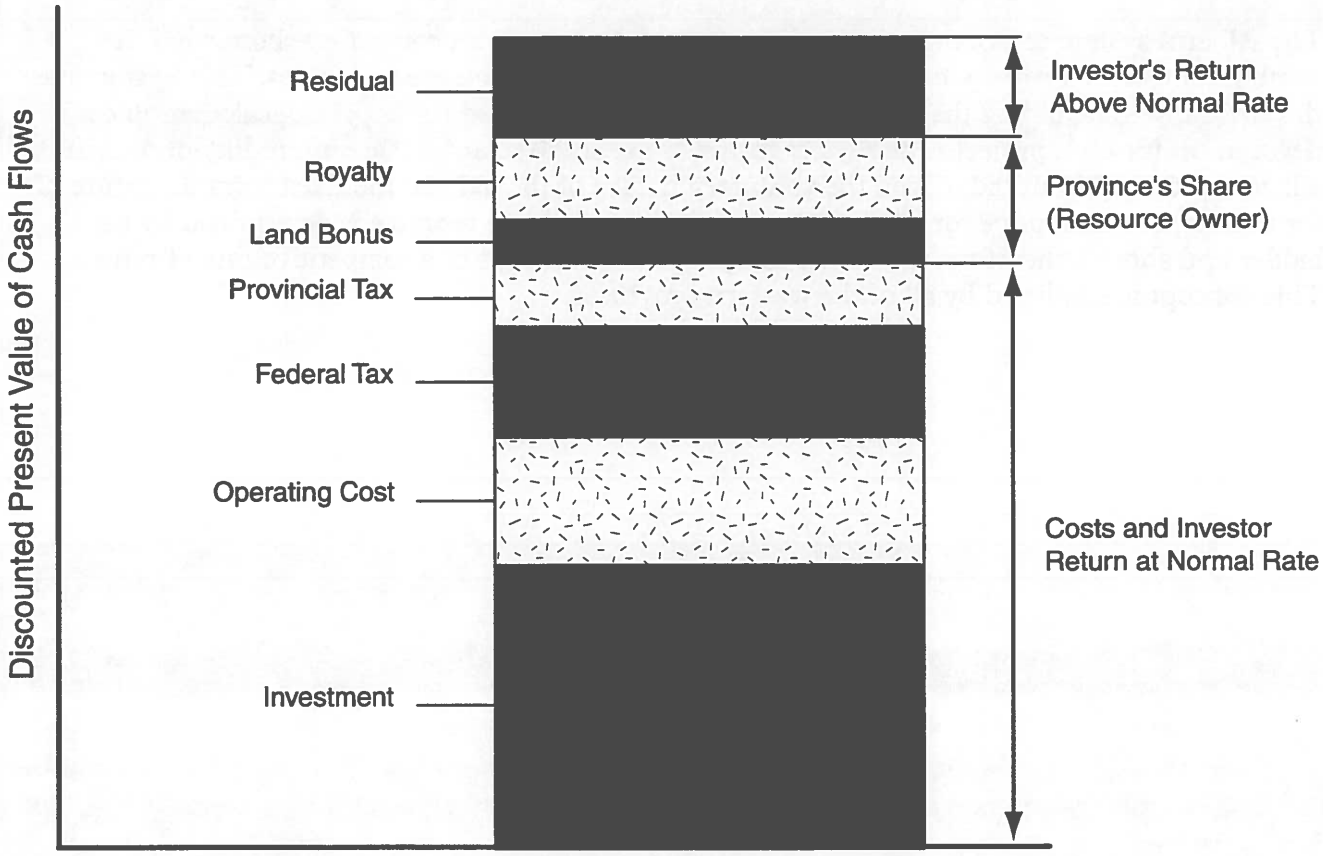
Pricing of exploitation rights for mineral resources can be problematic. The rights must be allocated by an efficient means, when a resource has yet to be discovered. The exploitation rights pricing formula must be considered fair by both industry and the resource owner.

The price for the right to exploit Alberta's petroleum resources is composed of an up-front competitive bid, plus the stream of royalty payments over the production life of a well. The competitive bid, based on a company's expectations of commodity price, exploitation costs (based on the company's knowledge of the quality of the resource to be discovered) and the royalty payments associated with extraction of the resource ensure a fair price for both the Crown and the producer.

Alberta's royalty formulas are designed to reduce the risks from unanticipated commodity prices. Since bids are made before the discovery of the resource, unexpected costs or commodity prices may result in the bids being viewed as too high, or too low. To reduce the risks to producers, the royalty formulas are directly sensitive to changes in price. Royalty rates also vary with production levels to extend the economic life of oil and gas reservoirs and share in the higher unit costs of smaller pools.

The Alberta system of pricing exploitation rights uses an up-front competitive bonus bid in combination with a royalty formula based on simple, readily measured variables. This System has the advantage of avoiding the administrative burden of a detailed rights pricing calculation or negotiation for each project. The royalty formulas are set to retain a share of production which allows for the up-front bid. Given the voluntary nature of the bid and the fixed formula nature of the royalty, the total price for the right to exploit the petroleum resource is determined by the bidder and should, therefore, reflect the company's expectations of a competitive rate of return. This concept is employed by all of the western provinces.

Figure 1 *Illustrates the components of a total allocation of project revenues.*



Conventional Crude Oil Crown Royalty - Graphic Comparison Between Provinces

The following pages present conventional crude oil royalty formulas for British Columbia, Alberta and Saskatchewan in graphic form. The graphs serve to illustrate royalty sensitivities to well productivity, oil classification (may be termed vintage or status), oil quality and price.

In the graphs depicting price sensitivity, heavy oil has a fixed production rate of 175 cubic metres (m^3) per month, while non-heavy oil has a fixed production rate of 300 m^3 per month. In the graphs depicting production sensitivity, heavy oil has a fixed price of \$85/m^3, while non-heavy oil has a fixed price of \$125/m^3. The select prices in effect for 1998 were used in the calculations.

Oil Classification

For royalty calculation purposes, each province has classified its oil resources into tiers according to either the date of discovery of the pool from which the oil is produced, or the finished drilling date of the well (see provincial regulations for specific criteria). The royalty formulas are set so that the newer classifications pay less royalty. In general, the tier classifications are as follows:

Alberta - based on date of discovery of pool.

Old Oil	pre-April 1974
New Oil	post-March 1974
Third Tier Oil	post-September 1992

British Columbia - based on date of discovery of pool.

Old Oil	pre-November 1975
New Oil	post-October 1975
Third Tier Oil	post-May 1998

Saskatchewan - based on finished drilling date of well.

Old Oil	pre-1974
New Oil	post-1973
Third Tier Oil	post-1993 (does not usually apply to horizontal wells)

Note that all heavy oil is classified as either New or Third Tier in Saskatchewan.

Manitoba - based on finished drilling date of well.

Old Oil	prior to April 1, 1974
New Oil	on or after April 1, 1974
Third Tier Oil	on or after April 1, 1999 (vertical wells only)
Incentive Oil	from 1987 to 1991 (EOR Incentive to January 1, 1992)

Production

All western Canadian provinces' oil royalties vary with well productivity.

Oil Density

For royalty calculation purposes, some Provinces' oil resources are classified by density:

Alberta

Type	Definition
Heavy Oil	oil with density $\geq$ 900 kg/m^3
Non-heavy Oil	oil with density $<$ 900 kg/m^3

Saskatchewan

Heavy oil is usually oil produced from zones below Viking in the Lloydminster and Kindersley-Kerrobert areas. Southwest-designated oil is oil produced after February 8, 1998 from the southwest area of the province. All other oil is classified as non-heavy.

Price

Alberta and Saskatchewan oil royalties vary with price; British Columbia and Manitoba oil royalties do not.

Inflation Adjustment

Royalty formulas are designed to make royalty rates rise with prices. Over the years, however, royalty rates have risen while prices have simply kept up with general price inflation. Alberta has recognised this problem and now indexes its select prices with inflation. This prevents royalty rates from rising as prices rise with general inflation. The graphs depicting Alberta's royalty rates are derived using 1998 select prices.

***1997 Conventional Crude Oil Production Statistics* – (1000m^3)**

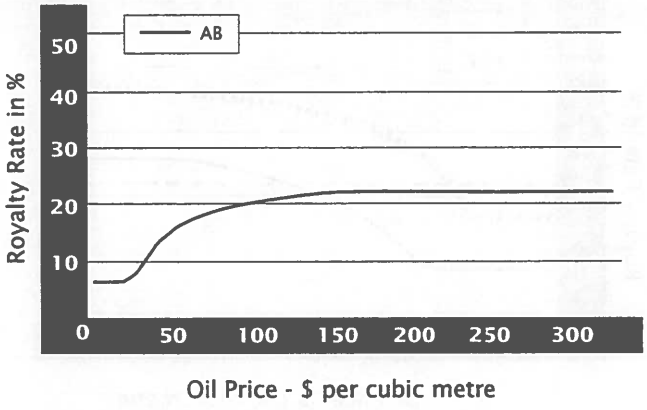
Alberta	British Columbia	Saskatchewan	Manitoba
52,818	2,540	23,325	637

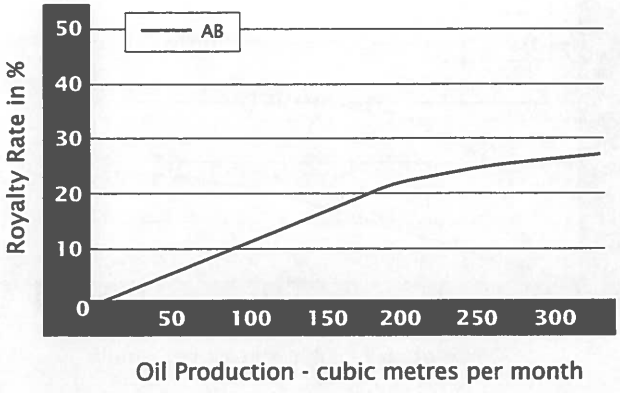
Source: Canadian Association of Petroleum Producers (CAPP)
Statistical Handbook – 1998 (British Columbia's revised)

Figure 2

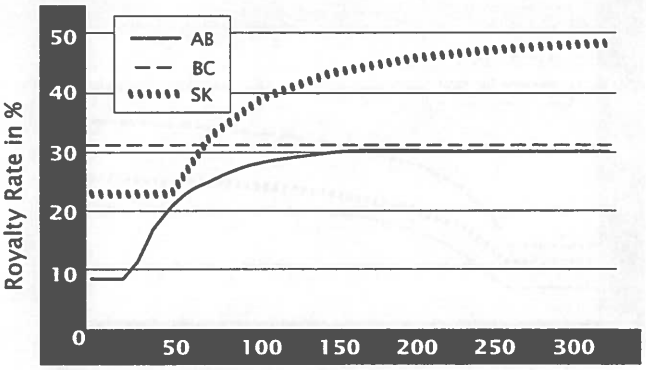
Old oil royalty rates as a function of oil classification, wellhead price and well productivity. Saskatchewan heavy oil has a classification of new or third tier oil. British Columbia currently has no heavy oil royalty rate.

OLD OIL - Heavy





OLD OIL - Non-heavy



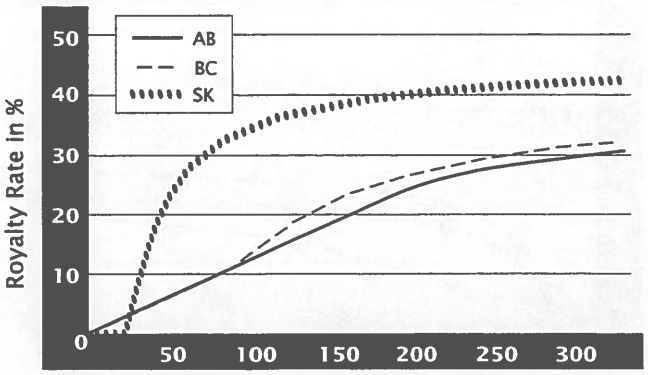


Figure 3

New oil royalty rates as a function of oil classification, wellhead price and well productivity. The density of Saskatchewan's southwest-designated oil (SOP) is equivalent to Alberta's heavy. British Columbia currently has no heavy oil royalty rate.

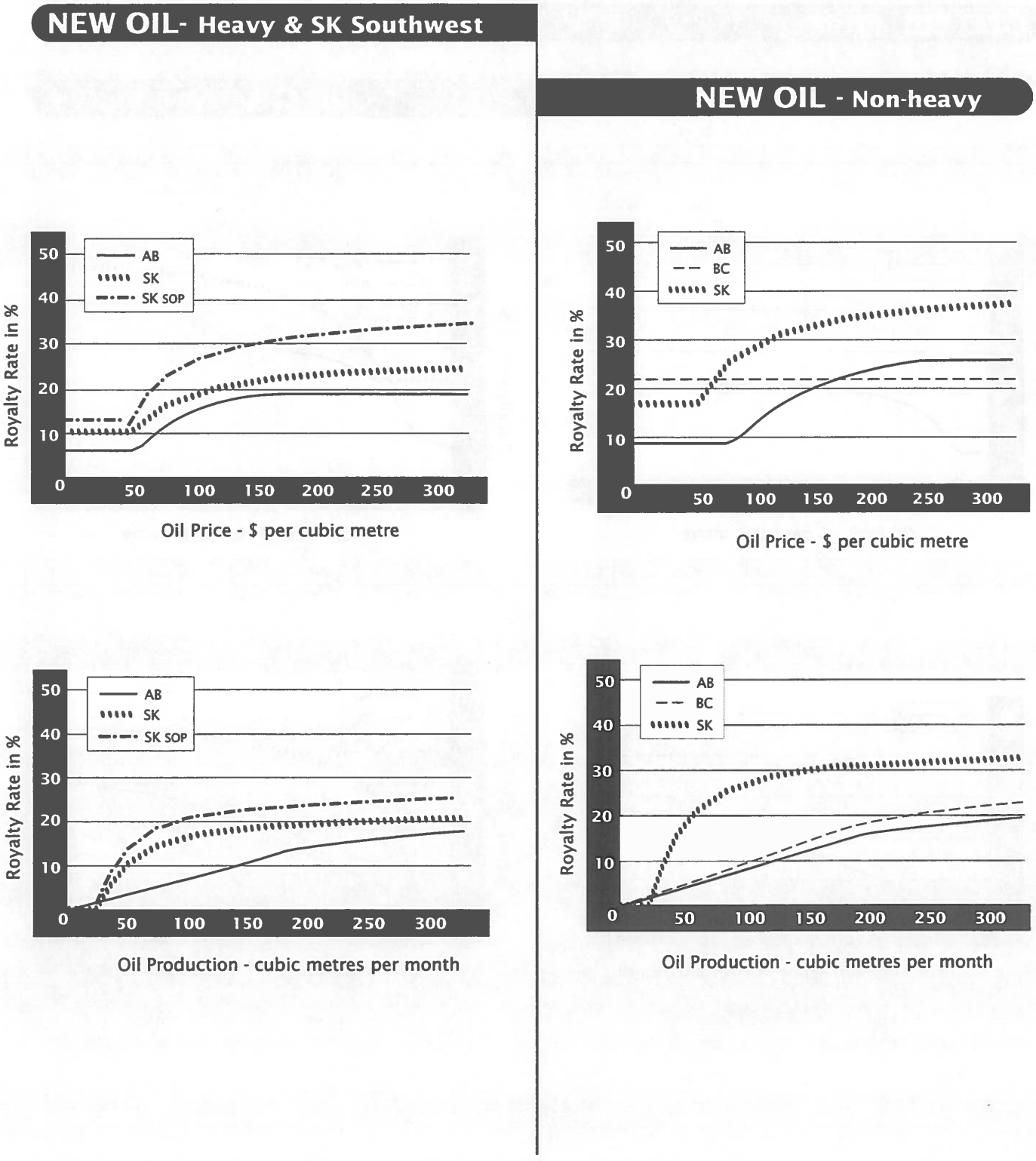
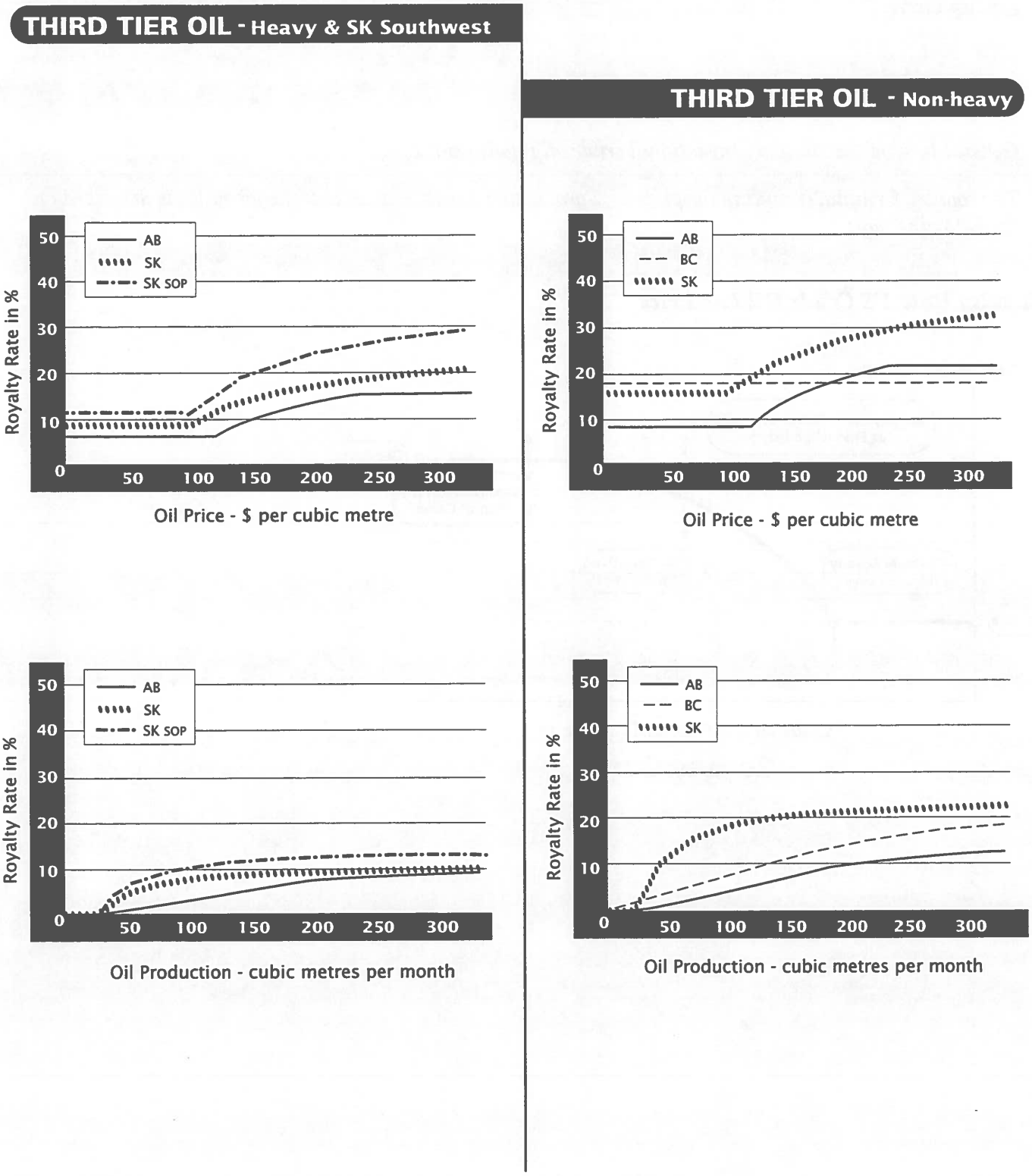


Figure 4

Third tier oil royalty rates as a function of oil classification, wellhead price and well productivity. The density of Saskatchewan's southwest-designated oil (SOP) is equivalent to Alberta's heavy. British Columbia currently has no heavy oil royalty rate.



Conventional Crude Oil Crown Royalty Formulas

Alberta

Objective:

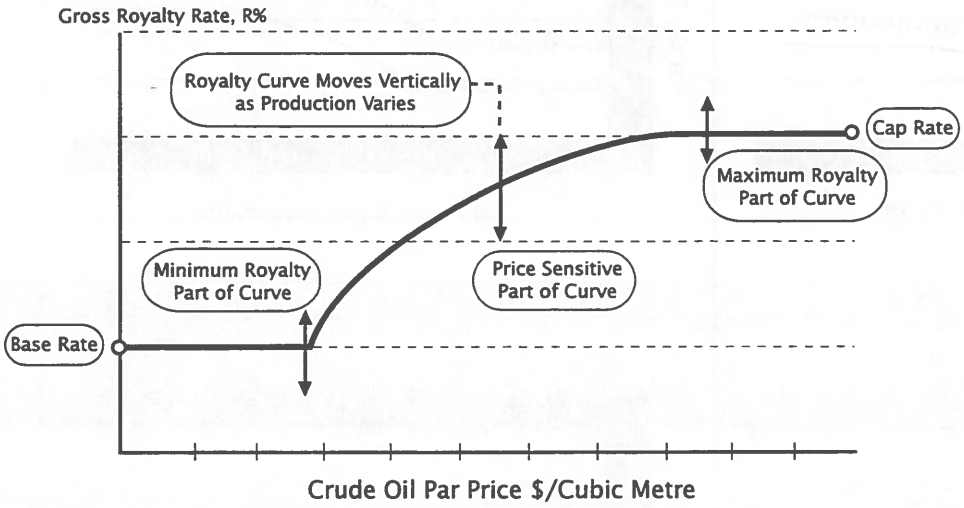
To determine a royalty share to be retained by the resource owner that is sensitive to crude oil price and quality, well productivity and oil pool classification. The parameters of the royalty formula are set at a reference well rate of 572.1 m^3/month. At this well production rate, the base rate is 10 % and the marginal rate is 40 %. The following graph depicts the general form of the royalty curve.

Figure 5

General form of the Alberta conventional crude oil royalty curve.

The royalty formula, including the price and production sensitive aspects of the formula, is described on the following page.

Royalty Rate VS Crude Oil Par Price



Royalty Curve

Conventional Crude Oil Crown Royalty Formulas

Alberta

R% = Royalty rate

$$R\% = \frac{BR \times B + MR \times (A-B)}{A} \times 100$$

where:

BR = Base Rate (see Production Sensitive Royalty)

MR = 4 x BR

A = Par Price (see Price Sensitive Royalty)

B = Select Price (see Price Sensitive Royalty)

Price Sensitive Royalty

The royalty rate is price sensitive within the following ranges:

Old Oil: for A > B and A < (6 x B)

New Oil: for A > B and A < (3 x B)

Third Tier Oil: for A > B and A < (2 x B)

Par and Select Prices

Separate par and select prices are set for non-heavy and heavy oils for determining royalty rates. Select prices are set annually and par prices are determined each month.

A = Par Price in $\$/m^3$ = average wellhead price

B = Select price in $\$/m^3$

Old Oil (pre-April 1974)

B = $\$26.31/m^3$ for both non-heavy and heavy oil for 1999

New Oil (post-March 1974)

B = $\$83.83/m^3$ for non-heavy oil for 1999

B = $\$56.54/m^3$ for heavy oil for 1999

Third Tier Oil (post-September 1992)

B = $\$120.33/m^3$ for both non-heavy and heavy oil for 1999

Minimum Royalty

A minimum royalty applies when the par price is less than the select price. In this case the royalty formula is R% = BR x 100.

Maximum Royalty

A maximum royalty applies when the par price reaches a certain limit. This maximum royalty differs for each classification.

Old Oil: for A ≥ (6 x B) R% = BR x 3.5 x 100

New Oil: for A ≥ (3 x B) R% = BR x 3 x 100

Third Tier Oil: for A ≥ (2 x B) R% = BR x 2.5 x 100

Note: At certain prices and at the same production level, the royalty rate for heavy oil may exceed the non-heavy rate. If this occurs, the rate is capped at the non-heavy rate.

Production Sensitive Royalty

Production sensitivity is given to the royalty formula through the base rate (BR).

$$BR = \frac{S}{Q}$$

where: S = the basic royalty in m^3
Q = monthly well production in m^3

for **Old and New Oil:**

$$S = \frac{Q^2}{2755.04} \text{ when } Q < 190.7 \text{ m}^3\text{/month}$$

$$S = 13.2 + [(Q - 190.7)x\ .115385] \text{when } Q \geq 190.7 \text{m}^3\text{/month}$$

for **Third Tier Oil:**

$$S = 0 \text{ when } Q < 20 \text{ m}^3\text{/month}$$

$$S = \frac{(Q-20)^2}{2207.46} \text{ when } 20 \geq Q < 190.7 \text{ m}^3\text{/month}$$

$$S = 13.2 + [(Q - 190.7)x\ .115385] \text{ when } Q \geq 190.7 \text{m}^3\text{/month}$$

Low Productivity Wells

Wells producing at rates of less than 190.7 m^3/month benefit from lower royalties. Third tier wells producing at rates of less than 20 m^3/month pay no royalty.

Simplified Royalty Calculation

A simplified version of the royalty formula is available for calculation of royalty liability. Required variables are reported monthly in *Alberta Energy Information Letters* (refer to contacts listed at the end of this report to obtain more information).

Royalty Payment

Of the regimes described in this report, Alberta's crude oil royalty regime is the only one that takes royalty in kind. Crown royalty volumes are delivered to agents on Alberta's behalf and the proceeds from their sale remitted to the Crown.

Conventional Crude Oil Crown Royalty Formulas

British Columbia

R% = Royalty rate

Q = Production (m^3/month)

$$R\% = \frac{Q}{K} \times 100 \text{ when } Q \leq C$$

$$R\% = \frac{A + [B \times (Q - C)]}{Q} \times 100 \text{ when } Q > C$$

Old Oil (November, 1975)

K = 792
A = 11.4

B = Percent of incremental production
= 40%

C = Production threshold for royalty calculation
= 95 m^3/month

New Oil (post-October, 1975)

K = 1058
A = 23.9

B = Percent of incremental production
= 30%

C = Production threshold for royalty calculation
= 159 m^3/month

Third Tier Oil (post-May, 1998)

K = 1322.5
A = 19.12

B = Percent of incremental production
= 24%

C = Production threshold for royalty calculation
= 159 m^3/month

Objective:

To determine a royalty share to be retained by the resource owner that is sensitive to well productivity and classification.

Old Oil

The old oil royalty formula retains between 0 and 12% of production for well production rates between 0 and 95 m^3/month. At well rates greater than 95 m^3/month, the marginal rate applied to production is 40%.

New Oil

The new oil royalty formula retains between 0 and 15% of production for well production rates between 0 and 159 m^3/month. At well rates greater than 159 m^3/month, the marginal rate applied to production is 30%.

Third Tier Oil

The third tier oil royalty formula retains between 0 and 12% of production for well production rates between 0 and 159 m^3/month. At well rates greater than 159 m^3/month, the marginal rate applied to production is 24%.

Low Productivity Wells

Old oil wells producing at rates less than 95 m^3/month, and new or third tier oil wells producing at rates less than 159 m^3/month benefit from lower royalties. There is no minimum rate for oil.

Conventional Crude Oil Crown Royalty Formulas

Saskatchewan

R% = Royalty rate

$$R\% = \left(K - \left(\frac{X}{MOP}\right) - SRC\right) \text{ to a minimum of } 0\%$$

where:

MOP = Monthly Oil Production (m^3/month)

X = K x 23.08

NOP = Average wellhead price of non-heavy oil ($/$m^3$), to a minimum of $50/$m^3$ for old and new oil and $100/$m^3$ for third tier oil

HOP = Average wellhead price of heavy oil ($/$m^3$) to a minimum of $50/$m^3$ for new oil and $100/$m^3$ for third tier oil.

SOP = Average wellhead price of southwest designated oil ($/$m^3$) to a minimum of $50/$m^3$ for new oil and $100/$m^3$ for third tier oil

SRC = Saskatchewan Resource Credit of either: a) 2.5% for vertical wells drilled, or waterflood projects after February 8, 1998, or b) 1% for all other oil

Old Oil (pre-1974)

$$K = 26 + \left(\frac{32.5 \times NOP - 50}{NOP}\right)$$

New Oil (post-1973)

$$K = 13 + \left(19.5 \times \frac{HOP - 50}{HOP}\right) \text{ for heavy oil}$$

$$K = 16.25 + \left(29.25 \times \frac{SOP - 50}{SOP}\right) \text{ for southwest oil}$$

$$K = 19.5 + \left(26 \times \frac{NOP - 50}{NOP}\right) \text{ for non–heavy oil}$$

Third Tier Oil (post-1993)

$$K = 13 + \left(19.5 \times \frac{HOP - 100}{HOP}\right) \text{ for heavy oil}$$

$$K = 16.25 + \left(29.25 \times \frac{SOP - 100}{SOP}\right) \text{ for southwest oil}$$

$$K = 19.5 + \left(26 \times \frac{NOP - 50}{NOP}\right) \text{ for non–heavy oil}$$

Objective:

To determine a royalty share to be retained by the resource owner that is sensitive to well productivity, crude oil price and classification. The intent of the Saskatchewan Resource Credit (SRC) is to take into account the non-deductibility of the Saskatchewan Corporate Capital Surcharge Tax.

Old Oil

The old oil royalty formula retains 20% of the first $\$50/m^3$ of the price and 45% of the remainder at a well reference rate of 100 m^3/month.

New Oil

The new oil royalty formula retains 15% (non-heavy), 12.5% (southwest) or 10% (heavy) of the first $\$50/m^3$ of the price and 35% (non-heavy and southwest) or 25% (heavy) of the price above $\$50/m^3$ at a well reference rate of 100 m^3/month.

Third Tier Oil

The third tier royalty formula retains 15% (non-heavy), 12.5% (southwest) or 10% (heavy) of the first $\$100/m^3$ of the price, and to take 35% (non-heavy and southwest) or 25% (heavy) of the price above $\$100/m^3$ at a well reference rate of 100 m^3/month. In general, the third tier structure does not apply to horizontal wells.

Low Productivity Wells

Wells producing at rates less than about 23 m^3/month are not subject to a royalty.

Conventional Crude Oil Crown Royalty Formulas

Manitoba

R % = Royalty rate

$$R\% = \frac{\text{Crown Royalty (S)}}{\text{Production (P)}} \times 100$$

where:

S = Base Crown royalty

P = Production (m^3/month)

$$S = K \times \frac{P^2}{265} \text{ when } P \leq 50 \text{ } m^3\text{/month}$$

$$S = K \times [9.43 + 0.45 \times (P - 50)] \text{ when } P > 50 \text{ } m^3\text{/month})$$

Old Oil (prior to April 1, 1974)

K = 1.00

New Oil (on or after April 1, 1974)

K = 0.55

Incentive Oil (1987 to 1991)

EOR Incentive Oil (1987 to January 1, 1992)

K = 0.35

Third Tier Oil (on or after April 1, 1999)

K = 0.47

Objective:

To determine a royalty share to be retained by the resource owner that is sensitive to well productivity and classification.

Old Oil

The old oil royalty formula retains between 0 and 18.9 % of production for well production rates between 0 and 50 m^3/month. For well production rates greater than 50 m^3/month, the marginal rate applied to production is 45 %.

New Oil

The new oil royalty formula retains between 0 and 10.4 % of production for well production rates between 0 and 50 m^3/month. For well production rates greater than 50 m^3/month, the marginal rate applied to production is 24.75 %.

Incentive and EOR Incentive Oil

The incentive oil royalty formula retains between 0 and 6.6 % of production for well production rates between 0 and 50 m^3/month. For well production rates greater than 50 m^3/month, the marginal rate applied to production is 15.75 %.

Third Tier Oil

The new oil royalty formula retains between 0 and 8.9 % of production for well production rates between 0 and 50 m^3/month. For well production rates greater than 50 m^3/month, the marginal rate applied to production is 21.15 %.

Low Productivity Wells

Wells producing at rates less than 50 m^3/month benefit from lower royalties.

Natural Gas Royalty - Graphic Comparison Between Provinces

The following page presents the natural gas royalty formulas for British Columbia, Alberta and Saskatchewan in graphic form. The graphs serve to illustrate royalty sensitivities to well productivity, classification and prices. In the graphs depicting price sensitivity, the well production rate is fixed at 25 thousand cubic metres (e^3m^3) per day. In the graphs depicting production sensitivity, price is fixed at $62 per e^3m^3. The select prices in effect for 1998 were used in the calculations.

Natural Gas Classification

For royalty calculation purposes, most provincial natural gas resources have been classified into tiers according to the date of discovery of the pool from which the gas is produced, the finished drilling date of the well and/or the date the oil and gas rights were acquired. The royalty formulas are set so that the newer classifications pay less royalty.

The tier classifications are as follows:

Alberta – based on date of discovery of pool.

Old Gas pre-1974

New Gas post-1973

British Columbia – based on date when the well was drilled and the date the oil and gas rights were acquired.

Non-Conservation Gas wells drilled prior to June 1998 (Old Gas in Charts)

New Wells on Existing Lands wells drilled after May 1998 on lands acquired prior to June 1998 (New Gas in Charts)

New Wells on New Lands wells drilled after May 1998 on lands acquired after May 1998 and before January 2002 (temporary feature)

Saskatchewan – based on date when gas was first produced from the well.

Old Gas pre-October 1976

New Gas post-September 1976

Third Tier Gas post-February 8, 1998 (based on finished drilling date of well)

Manitoba – does not classify its natural gas resources.

Production

Alberta and Saskatchewan natural gas royalties vary with well productivity. British Columbia and Manitoba natural gas royalties do not.

Prices

With the exception of Manitoba, the western Canadian provinces' natural gas royalties vary with price. In British Columbia, the price determination point is the plant inlet, as opposed to Alberta, where it is the plant outlet.

Inflation Adjustment

Some provinces' royalty formulas are designed so that royalty rates rise with prices. Over the years, however, royalty rates have risen as prices have simply kept up with general price inflation.

Alberta and British Columbia have recognised this problem and now index their select prices with inflation. This prevents royalty rates from rising as prices rise with general inflation.

1997 Natural Gas Production Statistics* – (1,000 e^3m^3)

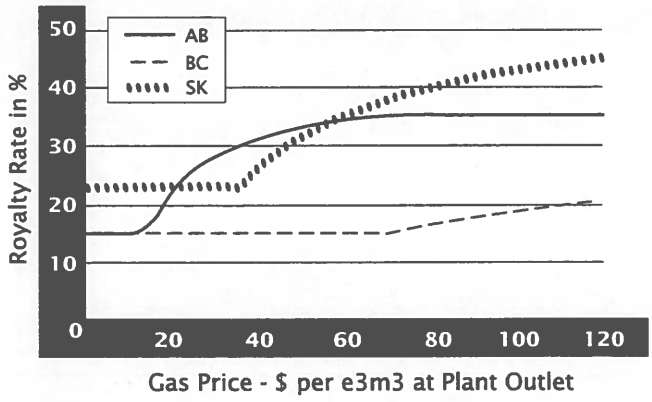
* at 101.325 kPa and 15° C.
Raw natural gas production less raw and processed gas injection.

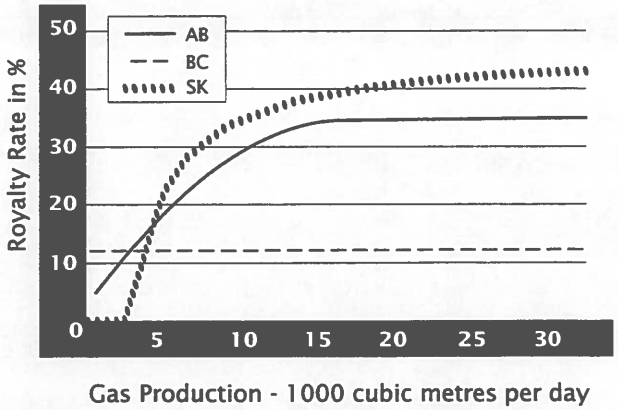
Alberta	British Columbia	Saskatchewan	Manitoba
156,675	23,601	7,781	none reported

Source: *CAPP Statistical Handbook - 1998*

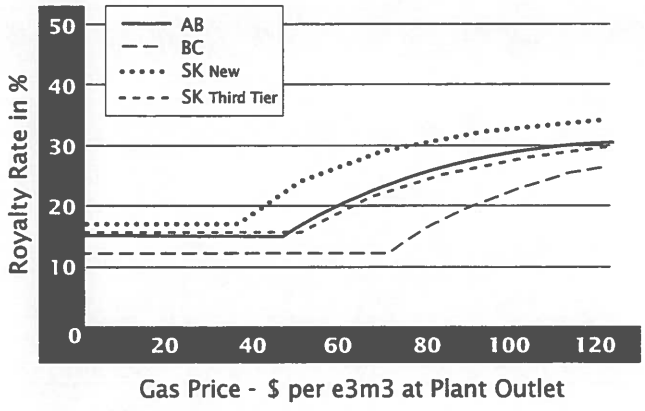
Figure 6 *Natural gas royalty rates as a function of price, well productivity and classification. Note that British Columbia's curve has been adjusted to reflect gross royalties to the same point as Alberta and Saskatchewan (average cost between plant inlet and the plant outlet).*

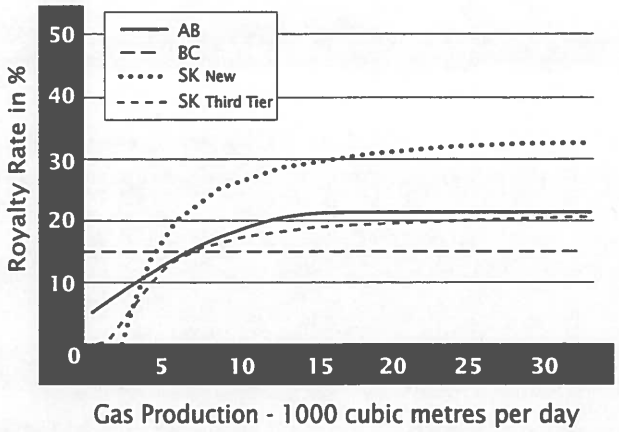
OLD GAS





NEW & THIRD TIER GAS





Natural Gas Crown Royalty Formulas

Alberta

R% = Royalty rate

J = Joule (a unit which expresses quantity of energy)

G = Giga (prefix for 10^9)

SP = Select Price ($/GJ) used in calculating royalty. There are separate select prices for Old and New classifications.

PP = Gas Par Price used in calculating royalty. PP is equal to the previous month's gas reference price.

RP = Gas Reference Price ($/GJ) is the weighted average of intra-Alberta consumer's price and ex- Alberta border price.

Old Gas (pre-1974) and **New Gas** (post-1973)

$R\% = 15$ when $PP \leq SP$

$$R\% = \frac{15 \times SP + 40 \times (PP - SP)}{PP} \text{ when } PP > SP$$

R% = a maximum of 35 for old gas

R% = a maximum of 30 for new gas

Low Productivity Allowance (Old and New Gas)

$$R\% = Rc\% - [(Rc\% - 5) \times (\frac{16.9 - ADP}{16.9})^2] \text{ when } ADP < 16.9$$

where:

Rc = Royalty percent (R%) as calculated before allowance

ADP = Average daily production (e^3m^3/day) over a month for a well

***Select Prices* $/GJ**

Year	*Old Gas*	*New Gas*
1999	0.351	1.181

Objective:

To determine a royalty share which is a percentage of the energy content, expressed in gigajoules, of the Crown ownership share of production. The royalty share is sensitive to the current market price and the classification of the reserves, with adjustments for low productivity wells. There is no distinction among raw gas, residue gas and ethane for calculating a royalty share.

Crown Royalty Volumes Valuation

In 1998, clients were given a one-time choice of one of two valuation methods:

1. Valuation at the gas Reference Price; or
2. Valuation at a Corporate Average Price (CAP).

If using CAP, the Crown's royalty volumes cannot be valued at less than 90% of the gas reference price. New clients have a one-time choice between the two methods.

Low Productivity Wells

Gas wells producing at less than 16.9 e^3m^3/day are entitled to an allowance which reduces royalty rates to as low as 5%. Gas produced from oil wells is currently eligible for this allowance at the same threshold, if the oil production is less than 0.15 m^3/day.

Natural Gas Crown Royalty Formulas

British Columbia

R% = Royalty rate

RP = Reference Price ($/e^{3}m^3) is the greater of Selling Price at the plant inlet or PMP (Posted Minimum Price).

SP = Select Price ($/e^{3}m^3), used in calculating royalty. For 1999 and all prior years, the select price is $50. For Non-Conservation gas produced from wells drilled prior to June 1998, the select price is permanently fixed at $50.

Non-Conservation Gas (wells drilled prior to June 1998)

$$R\% = \frac{750 + 25 \times (RP - 50)}{RP}$$ to a minimum of 15%

Non-Conservation Gas (wells drilled after May, 1998 on oil and gas rights held on or before June, 1998)

$$R\% = \frac{12 \times SP + 40 \times (RP - SP)}{RP}$$ to a minimum of 12%, maximum of 27%

Non-Conservation Gas (wells on Land Rights Acquired between June 1, 1998 and December 31, 2001)

$$R\% = \frac{9 \times SP + 40 \times (RP - SP)}{RP}$$ to a minimum of 9%, maximum of 27%

Conservation Gas

$$R\% = \frac{400 + 15 \times (RP - 50)}{RP}$$ to a minimum of 8%

Objective:

To determine a royalty share to be retained by the resource owner that is sensitive to gas prices above the select price. A posted minimum price (PMP) for natural gas to be used in the calculation of the royalty rate and royalty payable. As of February 1998, the PMP is set for each of five different provincial areas.

Non-Conservation Gas

For wells drilled before June 1998, the royalty formula retains $7.50 of the price, when the price is less than or equal to $50, and to take 25% of the price in excess of $50.

For new wells on lands acquired before June 1, 1998, the royalty formula retains 12% of the select price, when the price is less than or equal to the select price, and 40% of the price in excess of the select price.

For new wells on lands acquired between June 1, 1998 and December 31, 2001, the royalty formula retains 9% of the select price, when the price is less than or equal to the select price, and 40% of the price in excess of the select price.

Conservation Gas

The conservation gas royalty formula retains $4 of the price, when the price is less than or equal to $50, and 15% of the price in excess of $50.

Low Productivity Wells

There is no special allowance for low productivity wells.

Natural Gas Crown Royalty Formulas

Saskatchewan

R% = Royalty rate

R% = a minimum of 0%

R% = (C x MGP) – SRC when MGP ≤ 115.4 e^3m^3/month

$$R\% = \left(K - \frac{X}{MGP}\right) - SRC \text{ when } MGP > 115.4\ e^3m^3/\text{month}$$

where:

MGP = Monthly Gas Production (e^3m^3/month)

PGP = Provincial average fieldgate price ($/$e^3m^3$) as determined by the Saskatchewan Department of Energy and Mines, to a minimum of $35/$e^3m^3$ for new and old gas, and $50/$e^3m^3$ for third tier. The price is determined prior to the deduction of gas cost allowance.

SRC = Saskatchewan Resource Credit of either: a) 2.5% for wells drilled after February 8, 1999, or b) 1% for all other gas wells.

$$C = \frac{K}{230.76}$$

$$X = K \times 57.69$$

Old Gas (pre-October 1976)

$$K = 26 + \left(32.5 \times \frac{PGP - 35}{PGP}\right)$$

New Gas (post-September 1976)

$$K = 19.5 + \left(26 \times \frac{PGP - 35}{PGP}\right)$$

Third Tier Gas (post-February 8, 1998)

$$K = 19.5 + \left(26 \times \frac{PGP - 50}{PGP}\right)$$

Gas Associated with Oil

R% = 0%

Objective:

To determine a royalty share to be retained by the resource owner that is sensitive to well productivity, price and classification. The Saskatchewan Resource Credit (SRC) was introduced in 1988 to take into account the non-deductibility of the Saskatchewan Corporate Capital Surcharge Tax.

Old Gas

The old gas royalty formula retains 20% of the first $35 of the price and 45% of the remaining price at a well reference rate of 250 e^3m^3/month.

New Gas

The new gas royalty formula retains 15 % of the first $35 of the price, and 35 % of the remaining price at a well reference rate of 250 e^3m^3/month.

Third Tier Gas

The third tier gas royalty formula retains 15 % of the first $50 of the price and 35 % of the remaining price at a well reference rate of 250 e^3m^3/month

Low Productivity Wells

There is no special allowance for low productivity wells.

Manitoba

R % = Royalty rate

R % = 12.5 % of monthly sales

Objective:

To have a flat royalty of 12.5 % on natural gas consumed or sold from a location.

Low Productivity Wells

There is no special allowance for low productivity wells.

Cost Allowances

Alberta

Gas Cost Allowance

The gas cost allowance (GCA) is a deduction from gross royalties payable on natural gas and by-products to compensate for the costs of gathering, compressing and processing the Crown royalty share. The allowance is determined on the basis of:

- **Annual Capital Cost Allowances** to royalty clients that own gathering, compressing and processing facilities. The capital cost allowance calculation includes a 15 % return on investment;
- **Monthly Operating Cost Allowances** to all royalty clients; and,
- **Annual Custom Processing Cost Allowances** to royalty clients that pay for gas gathering, compressing or processing on a fee for service basis.

For any royalty client, total cost allowances for a year cannot exceed the total value of royalty payable for that year. Excess cost allowances are not recoverable in other years.

For detailed information on GCA rates and business rules refer to the contacts listed at the end of this report.

British Columbia

Producer Cost of Service Allowance

Gas producers are eligible to receive the producer cost of service allowance (PCOS) for field gathering, dehydration, compression, field processing and conservation. It is a plant specific, fixed rate deduction from gross natural gas royalty.

Royalty clients that utilise gathering, compressing and processing facilities are eligible for Annual Capital and Operating Cost Allowances. The capital cost allowance calculation includes a 15 % return on investment, increased from 12.5 % effective June 1998.

For detailed information on PCOS rates refer to the contacts listed at the end of this report.

Saskatchewan

Saskatchewan producers receive a deemed gas cost allowance of $\$10/e^3m^3$. This allowance is in recognition of costs incurred in gathering and compressing the natural gas. The costs of processing gas are excluded from the allowance because the vast majority of natural gas is dry gas that does not require further processing. The majority of gas that does require processing is produced from oil wells that normally subject to royalty.

Manitoba does not have a gas cost allowance.

Natural Gas By-products Crown Royalty Formulas

Alberta

Pentanes Plus:

R% = Royalty rate

$$R\% = \frac{22 \times B + [C \times (F - B)]}{F}$$

where:

F = Average selling price ($/m^3)

B = Select Price for 1999 = $42.73/m^3

Old Pentanes Plus (pre-1974)

C = 50

New Pentanes Plus (post-1973)

C = 35

Objective

To take 22% of the first $42.73 of the price and 50% and 35% of the price in excess of $42.73 for old and new pentanes plus, respectively.

Butane & Propane:

Royalty is levied at a rate of 30% of production.

Sulphur

Royalty is levied at a rate of 16 2/3% of production.

Ethane

See "Natural Gas Crown Royalty Formula".

British Columbia

Royalties on natural gas liquids are levied at a flat rate of 20% of the sales volume.

Royalties on sulphur are levied at a flat rate of 16 2/3 % of the sales volume.

Saskatchewan

The majority of natural gas by-products are derived from associated gas which is not subject to a direct royalty or tax. By-products contained in natural gas that is marketed in a raw (unprocessed) state are subject to the natural gas royalty/tax.

Manitoba

Royalties and taxes are not levied separately on natural gas by-products. The levy on raw natural gas encompasses by-products.

Other Features of the Provincial Royalty Regimes

Crude Oil Royalty Holidays

Alberta

Third Tier Exploration Oil Royalty Holiday

Refer to Alberta Energy Information Letter 93-8.

Qualifying Wells

A third tier exploratory well is an oil or oil sands well spudded after September 30, 1992. It is classified by the AEUB as a New Field Wildcat (NFW), New Pool Wildcat (NPW), or Deeper Pool Test (DPT). The exploratory interval in an NFW and NPW well is the interval that extends from the surface to total depth. In a DPT well, the interval identified by the AEUB as exploratory extends from the base of the deepest established pool to total depth. The third tier exploratory oil produced from the exploratory interval in a well qualifies for the holiday.

Non-Qualifying Types of Wells

A Development well is a well that is not an exploratory well. If a Development well, Outpost well or Shallow Pool Test finds a new pool, the pool is classified as third tier oil, but does not qualify for a 1 year holiday.

Benefit

A royalty holiday on the first 12 production months or $1,000,000, valued at par price, is applied to the combined production from the entire exploratory interval of the well, regardless of the number of drilling, deepening or completion events.

Reactivated Oil Well Holiday

Refer to Alberta Energy Information Letter 93-3.

Qualifying Type of Wells

A reactivated well is an oil or an oil sands well that was reactivated on or after October 1, 1992, after the well did not produce any substance during its qualifying period. This period comprises the 12 consecutive months preceding the month in which reactivation took place, if that month was October, November or December 1992 or January 1993. If the well was reactivated in February 1993 or later, the period consists of the preceding 24 months. Eligible oil from a reactivated well is oil or oil sands obtained from a pool or oil sands deposit that was penetrated by the well at the time the well commenced reactivated production. Production from deeper pools or deposits penetrated after the well commenced or resumed production is not eligible.

Non-Qualifying Wells

Wells eligible for benefits under another royalty reduction program will not qualify for both benefits. Wells in enhanced oil recovery projects or eligible for an oil sands agreement or experimental royalties will be specifically excluded.

Benefits

The royalty holiday is available from the reactivation date until 8,000 m^3 have been produced in aggregate from the reactivated well. Production of crude oil or oil sands from all events in the reactivated well is exempt from Crown royalty that would otherwise be payable under the Petroleum Royalty Regulation or the Oil Sands Royalty Regulation, 1997. Production from each producing event of an eligible reactivated well that has retained Old Oil status will be certified as New Oil after the well reaches the 8,000 m^3 production limit. An application is not required to qualify for the program.

Crude Oil Royalty Holidays

British Columbia

Discovery Oil Royalty Holiday

Oil produced from a new pool discovery well is royalty exempt for the first 36 producing months or 11,450 m^3, whichever comes first.

Manitoba

The Manitoba Drilling Incentive Program provides the licensee of new wells or qualifying wells with a royalty/tax free "holiday oil volume". No royalties or taxes are payable until the holiday oil volume has been produced. The program consists of 5 components: New Well Holiday Oil Volume, Special New Formation Holiday Oil Volume, Marginal Well Major Workover Holiday Oil Volume, Holiday Oil Volume Account and the Horizontal Well Holiday Oil Volume (see Horizontal Well Features).

New Well Holiday Oil Volume (Until 2004)

New wells drilled prior to January 1, 2004, qualify for a royalty/tax free production volume. The holiday volume is sensitive to oil price and is dependent on the well's location. The maximum holiday volume is 10,000 m^3 or 10 years of production, whichever occurs first. No application is required to receive the holiday oil volume.

The holiday volume is calculated in accordance with the following equations:

If $D \leq 2$ kilometres: $HOV = D\,(A) + B$

If $D > 2$ kilometres: $HOV = A'\,(D2) + B'$

where:

HOV = The holiday oil volume in m^3 earned by the well

D = Distance in kilometres from the nearest well which, as of the finished drilling date of the new well, is cased for production from the same or a deeper formation penetrated by the new well.

$A = 1.7\,P + 230$

$B = 3130 - 13.6\,P$

$A' = 0.17\,P + 106.9$

$B' = 3163 - 10.9\,P$

P = Average Price ($/$m^3$)

Special New Formation Holiday Oil Volume (Until 2004)

Any well that is the first in Manitoba to produce from a non-productive formation deeper than the Mississippian Bakken Formation and is drilled prior to January 1, 2004, is provided with a holiday volume of 50,000 m^3. This volume must be produced within 10 years of the finished drilling date and is not transferable to a holiday oil volume account. An application is required to claim this incentive.

Marginal Well Major Workover Holiday Oil Volume (Until 2004)

Any marginal well where a major workover is completed prior to January 1, 2004 earns a holiday oil volume of 500 m^3. A marginal well is defined as a well drilled at least 12 months ago that, over the previous 12 months, has been shut in or has an average oil production rate of less than 1 m^3 per operating day.

Holiday Oil Volume Account

Each licensee of a well or wells may establish a holiday volume account. The purpose of such an account is to provide flexibility in the allocation of earned holiday volumes. This account may be used to bank and allocate holiday volumes earned by the licensee. Several rules apply (refer to contacts listed at the end of this report).

Saskatchewan does not offer any oil holiday programs. See other oil royalty features.

Other Oil Royalty Features

Alberta

Low Productivity Oil Wells

Refer to Alberta Energy Information Letter 93-2.

Qualifying Types of Wells

- Oil well or oil sands well.
- The well did not produce more than 121 m^3/month of oil or oil sands in any month during the qualifying period.
- The qualifying period consists of the 12 consecutive months that end in September, October, November or December 1992, or the 24 consecutive months ending in January 1993 or later.
- Average monthly production for the well is 73 m^3 or less during the most recent 6 months that the well produced, providing those months occurred within the qualifying period.
- Eligible oil from a low-productivity well is oil or oil sands obtained from a pool or oil sands deposit that was penetrated by the well at the end of the wells' qualifying period. Production from deeper pools or deposits penetrated after the well's qualifying period is not eligible.

Benefits

For the first 16,000 m^3 of gross oil or oil sands production from each eligible well, the royalty rate will be the lower of 5% or the rate determined by the oil royalty formula. An application is not required to qualify for the program.

Experimental Conventional Oil Projects

Refer to Alberta Energy Information Letter 92-8.

Experimental oil projects approved by the AEUB are eligible for a flat royalty rate of 5% of production.

Other Oil Royalty Features

Saskatchewan

Exploratory Oil Volume-based Royalty/Tax Reduction

Non-deep exploratory wells (located at least 3 kilometres from the nearest oil well or producing from a geological system below all other oil wells within 3 kilometres) qualify for a royalty/freehold tax reduction on the first 8,000 m^3 of production.

Deep exploratory wells (located at least 3 kilometres from the nearest oil well or producing from a geological system below all other oil wells within 3 kilometres and producing oil from a geological system older than Mississippian, other than the Bakken formation and from a depth greater than 1,700 metres) qualify for a royalty/freehold tax reduction on the first 25,000 m^3 of production.

A maximum royalty/freehold tax of 5% less the SRC will apply to the volumes under both programs.

Development Oil Volume Based Royalty/Tax Reduction

Non-deep development wells drilled in the heavy oil areas qualify for a royalty/freehold tax reduction on the first 4,000 m^3 of production. Non-deep development wells drilled in non-heavy oil areas qualify for a reduction on the first 2,000 m^3 of production.

Deep development wells (produce oil from a geological system older than the Mississippian, other than the Bakken formation, and from a depth greater than 1,700 metres) qualify for a royalty/freehold tax reduction on the first 12,000 m^3 of production.

A maximum royalty/freehold tax of 5% less the SRC will apply to the volumes under both programs.

New or Expanded Waterflood Projects

The incremental oil production from these projects is subject to the third tier royalty/tax structure. A volume incentive is not available.

Oil Well Reactivation Program

Oil production from qualifying reactivated oil wells will be subject to a maximum new oil royalty tax rate of 5% less the SRC for a period of 5 years from the date of reactivation, and the applicable new oil royalty/freehold tax rates will apply thereafter.

Only those wells reactivated after 1993 which were shut-in or suspended during the entire 1993 calendar year will qualify under this program.

Horizontal Well Features

Alberta

Horizontal Re-entry Oil Royalty Reduction

Refer to Alberta Energy Information Letter 93-4.

Qualifying Types of Wells

The following criteria must be met:

- A horizontal wellbore was drilled from an existing wellbore to extend at least 100 metres beyond the point where the wellbore deviates 80 degrees from vertical.
- The horizontal drilling activity started on or after October 1, 1992, and at least 5 years after the finished drilling date of the existing wellbore.
- The average of the 12 latest months with production establishes the "maintenance volume" for a well from a pool. These production months occurred both within the year of re-entry and the previous 4 years.
- For an injector well that is converted to a producing well by re-entry, the maintenance volume is established by the latest 12 months in which the well produced. If the well does not have 12 months of production during the year of re-entry plus the 4 previous years, the maintenance volume will be based on the 12-month average for the well(s) where production was enhanced by the injected substance (e.g., the four producing wells in a five-spot pattern).
- Production obtained through the horizontal extension is from the same pool as the maintenance volume.
- Application to the Department is filed by the well operator.
- Notification of qualification is issued by the Department.

Exclusions

A well is excluded from qualifying during the period in which one of the following circumstances is in effect:

- royalty for the well event is calculated under another;
- a well is within a Petroleum Royalty Regulation, Section 11, EOR scheme boundary or 0.8 kilometres beyond; or
- royalty is reduced under Petroleum Royalty Regulation, Section 10.

The horizontal re-entry well royalty reduction terminates when the well qualifies as either a low-productivity well or becomes a reactivated well, unless the benefits under these regulations are revoked by the Department.

Benefits

The royalty rate will be capped for oil produced from an eligible horizontal extension. The cap will be the royalty rate associated with the average production volume for the latest 12 months when production occurred before re-entry. For a well with a 12-month production average of up to 184 m^3/month, royalty will be capped at one half that rate for the incremental production that exceeds the qualifying average. For program purposes, the average 12-month qualifying production is referred to as the "maintenance volume".

British Columbia does not have a horizontal drilling regime.

Horizontal Well Features

Saskatchewan

Horizontal Oil Well Volume-based Royalty/Tax Incentives

For horizontal oil wells with a total horizontal section length of 300 metres or more, which are not re-entry wells, the first 12,000 m^3 of oil production from a non-deep well or the first 25,000 m^3 from a deep well is subject to a maximum royalty/freehold tax of 5% less the SRC

Horizontal Short Section Volume-based Royalty/Tax Incentives

For horizontal wells with a total horizontal section length of less than 300 metres, which are not re-entry wells, the first 12,000 m^3 of oil produced from a non-deep oil well or the first 25,000 m^3 of oil produced from a deep well is subject to a maximum royalty/freehold tax of 10% less the SRC.

Horizontal Re-entry Oil Volume-based Royalty/Tax Incentives

For horizontal re-entry wells, the first 12,000 m^3 of oil production from a non-deep well or the first 25,000 m^3 of oil production from a deep well is subject to a maximum royalty/freehold tax of 10% less the SRC.

All horizontal oil wells are subject to the new oil royalty/freehold tax rates following production of the incentive volume except for incremental water flood oil from water flood projects commencing after 1993, which is subject to third tier royalty/freehold tax rates.

Manitoba

Horizontal Well - Holiday Oil Volume (To 2002)

A horizontal well (defined as a well that achieves an angle of 80 degrees from vertical for a minimum distance of 100 metres or a recompletion of an existing well that meets these criteria) drilled prior to January 1, 2002, earns a holiday volume of 10,000 m^3. This volume must be produced within 10 years of the finished drilling date.

All horizontal wells are classified as new oil wells for royalty and tax purposes.

Holiday volumes earned by a horizontal well can be transferred to the licensee's holiday volume account.

Enhanced Oil Recovery (EOR) Royalty Relief

Alberta

The Alberta enhanced oil recovery royalty regime facilitates the use of EOR methods for conservation of petroleum resources. The Enhanced Recovery of Oil Royalty Reduction Regulation provides for Crown sharing in the incremental costs of enhanced oil recovery through a reduction in royalties on incremental tertiary production.

The allowable EOR costs are incremental to the base case recovery scheme and approved by the Department of Energy. The major cost categories are as follows:

- Capital
- Consumed Energy
- Injectant
- Breakthrough Processing Allowance
- Transportation
- Overhead Allowance

Tertiary revenues are determined by a tertiary factor, which deems a portion of the oil recovered from a scheme as incremental tertiary production. The tertiary (t) factor is the lesser of 0.9 or the result of the following formula:

$$\text{t Factor} = \frac{\text{incremental tertiary reserves over scheme life}}{\text{remaining recoverable reserves at start of tertiary flood}}$$

The reduction in oil royalties is the lesser of:

- Scheme allowed costs x crown interest x royalty rate, or
- Scheme oil production x crown interest x royalty rate x t factor x oil par price.

The Department of Energy evaluates each application for royalty reduction in consultation with the EUB. The key criteria for scheme approval are:

1. The scheme must receive technical approval from the EUB under Section 26 of the Oil and Gas Conservation Act.
2. The scheme must use the injection of hydrocarbons, carbon dioxide, nitrogen, chemicals or other material approved by the Minister.
3. The scheme is likely to produce more crude oil from the pool than could be produced under the base recovery scheme for that pool.
4. The costs to implement and operate the EOR scheme are significantly greater than the costs to implement and operate the base recovery scheme.

Saskatchewan

The Saskatchewan enhanced oil recovery royalty regime is a cost sensitive system that recognises the higher investment and operating costs associated with EOR projects. The royalty level is based on project profitability both before and after payout of investments. The EOR royalty regime applies to any project that enhances the total recovery of oil through the use of thermal or other techniques.

The EOR royalty regime does not apply to waterflood projects. The EOR royalty rate is calculated as follows:

	Crown Lands	*Crown-Acquired Lands*	*Freehold Lands*
Before Payout	Intermediate (1 % of gross revenue, 5 % of gross revenue, 10 % of net revenue)	Intermediate (1 % of gross revenue, revenue, 5 % of gross revenue,10 % of net revenue) – Lease Royalty	Nil
After Payout	Greater (5 % of gross revenue, 30 % of net revenue)	Greater (5 % of gross revenue, 30 % of net revenue) – Lease Royalty	23 % of net revenue

Gross revenue is based on the EOR oil production from a project. The EOR oil is determined by multiplying the total oil production from the project by the EOR factor (additional recoverable reserves/total remaining recoverable reserves). The EOR factor for heavy oil projects is 100 %. The net revenue is equal to the gross revenue and recovered investment less operating costs and net royalty payments.

All EOR oil production is eligible for the SRC. In general, the SRC is 2.5 % for new or expanded projects commencing after February 8, 1998 and 1 % for all other EOR oil. All EOR oil production from Crown-acquired lands will be treated as if it was produced from Crown lands effective February 28, 1998.

British Columbia and Manitoba currently have no specific programs in place for EOR. Provincial regulations may provide special royalty or tax reduction or exemption. In British Columbia this has been done by way of a royalty agreement.

Natural Gas Royalty Features

Alberta

Deep Gas Royalty Holiday (DGRHP)

Refer to Alberta Energy Information Letter 85-29.

A holiday applies to all new wells or deepened wells drilled into previously undefined gas pools or extensions of existing pools located below 2,500 metres. The drilling spacing unit must be wholly outside the deep gas pools as defined by the AEUB.

The holiday is defined in terms of a dollar amount applied against royalties, which increases with well depth and hence the cost of incremental drilling below 2,500 metres. The royalty holiday applies until the value of the natural gas and by-products exempted equals the amount determined by a depth-base schedule (see table below). The maximum value is $3.6 million. Entitlements must be used within 10 years of completing drilling.

Depth (m)	Cumulative Value ($000)	IncrementalValue ($/metre)
2500	0	1000
3000	500	1000
3500	1000	1000
4000	1500	1300
4500	2150	1300
5000	2800	1600
5500	3600	———

British Columbia

Natural Gas Royalty Reduction

Non-Conservation Gas from wells drilled on land rights acquired between June 1, 1998 and December 31, 2001 qualify for a reduced royalty rate on their lifetime production volumes. Under this program, the minimum royalty rate has been reduced to 9 %. See "Natural Gas Crown Royalty Formulas".

Saskatchewan

Natural Gas Exploration Incentive

The first 25 million m^3 of natural gas produced from a qualifying exploratory natural gas well will be subject to a maximum new gas royalty/tax of 5 % less the SRC.

To qualify, a gas well must be drilled a minimum of 4.8 kilometres from the nearest gas well or producing from a geological system below all other gas wells within 4.8 kilometres.

Manitoba does not offer natural gas royalty holidays.

Non-Conventional Crude Oil/Oil Sands Royalty

Alberta

Background

In 1993, industry and government formed the joint National Task Force on Oil Sands Strategies. In spring 1995, the Task Force released a comprehensive report detailing its recommended royalty and tax terms for the oil sands industry in Alberta. The Task Force recommended that this regime be established by legislation rather than through individual Crown agreements. On November 30, 1995, Premier Ralph Klein announced that a generic royalty regime would be developed for Alberta's oil sands.

Objectives

The objectives of the royalty regime are as follows:

- To optimise the sustained contribution from Alberta's resources in the interests of Albertans.
- To establish a single, clear and stable royalty regime that is applicable to all new investments in oil sands and facilities development without the province of Alberta having to provide grants, loans, loan guarantees, or become directly involved in any capacity other than as resource owner.
- To ensure that oil sands development in Alberta is generally competitive with other petroleum development investment opportunities around the world.

Legislation

To achieve these objectives, the Crown amended the Mines and Minerals Act, May 1997, embedding royalty formulas and the applicable return allowance rate in the Act itself.

The Oil Sands Royalty Regulation, 1997 (AR 185/97), outlines the main administrative provisions, most notably the following areas:

- requirements for Project approval;
- royalty based on revenue minus costs;
- definition of allowed costs; and
- reporting and payment mechanisms.

Key Features of the Oil Sands Royalty Regulation, 1997

The Regulation applies to all new investment in the oil sands whether they are new projects or expansions of existing projects.

Prior to a projects payout (i.e., when the developer has recovered all allowed project costs plus a return allowance), the applicable royalty is 1 % of project gross revenue. Subsequent to a project's payout, the applicable royalty is the greater of 25 % of project net revenue, or 1 % of gross revenue.

The return allowance is set at the Government of Canada long-term bond rate. All cash costs (operating and capital) of the project are 100 % deductible in the year in which they are incurred.

Oil & Gas Royalty Regulations in the Territories

Northwest and Nunavut Territories

On April 1, 1999, the Northwest Territories was divided creating a new territory, Nunavut (which means "our land" in Inuktitut). Currently, the federal government manages oil and gas resources.

Under the *Canada Petroleum Resource Act* (CPRA) royalty regulations the royalty consists of a 1 % royalty on gross revenue at start-up, increasing by 1 % every 18 production months to a maximum of 5 %. The royalty remains at 5 % until payout when it converts to 30 % of net profit or 5 % of gross revenues, whichever is greater.

Net profit is calculated as:

Gross Revenue
- Allowed Operating Costs
- Allowed Capital Costs
= Net Profit

Operating and capital costs receive 10 % and 1 % uplifts respectively to recognise indirect expenses. Allowed capital costs incurred before the approval of the development plan receive 5 % uplift.

Prior to payout, unrecovered costs are given a return allowance equal to the long-term government bond rate plus 10 %. Royalty payout is attained when cumulative gross revenues exceed cumulative operating costs, capital costs, gross royalties and return allowance. Payout is calculated on a working interest basis, not on a project basis.

Yukon

In November 1998, the Yukon Territory was transferred authority for its oil and gas resources from the federal government. Royalty regulations are under development and expected in the spring of 1999, so they are not available by the publication date of this document.

For further information, refer to the contacts at the end of this report.

Petroleum and Natural Gas Rights

In Alberta and Saskatchewan, the provincial Crown owns approximately 80 % of petroleum and natural gas resource rights. In British Columbia, the Crown owns almost 100 % of producing oil and gas rights.

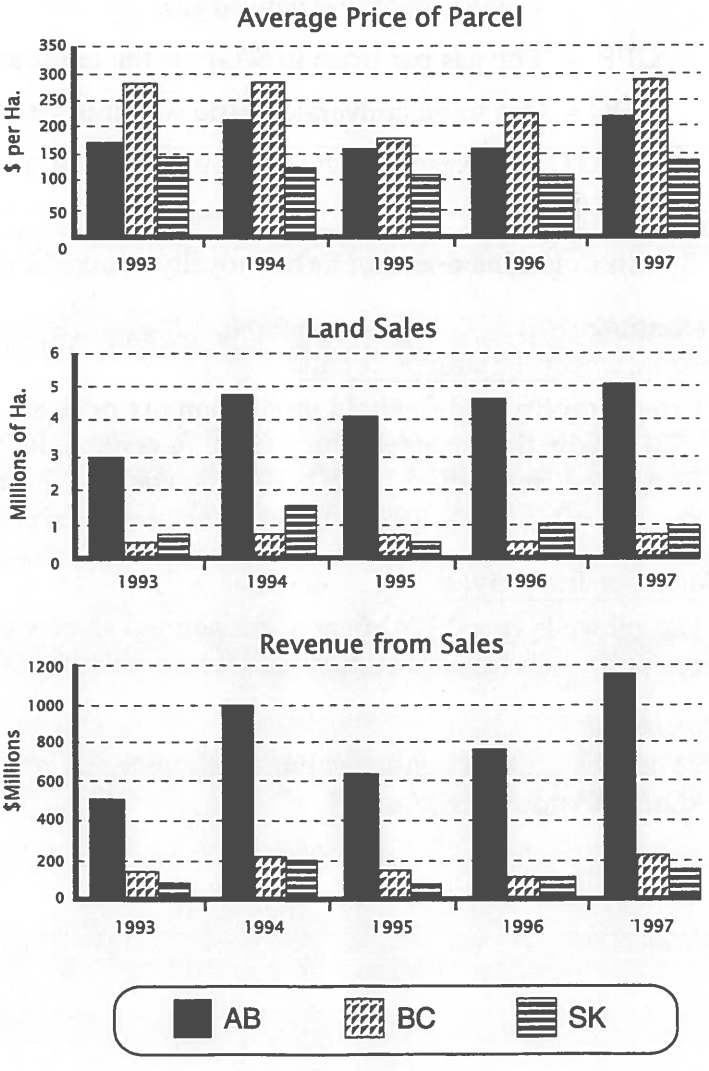
The total revenue received by a Province from the allocation of resource development rights generally has two major components: revenue from the allocation of the right to produce the oil or gas, and revenue from royalties on production from that lease. This section compares revenues received for the sale of rights for conventional oil and gas from Alberta, British Columbia and Saskatchewan.

The revenue from mineral rights comes from the allocation of rights by public tender. Industry submits sealed bids for each parcel. The highest bidder is typically awarded the parcel. The amount paid reflects industry's estimate of the difference between the present value of production revenues and the present value of costs, taxes and royalties over the time there is production from the leased lands. This tends to make total Crown revenues from comparable leases simila, despite differences in royalty rates and royalty reduction features available.

All of these provinces have systems in place for the disposition and posting of available Crown rights and identification of access constraints and potential land use conflicts. In Alberta, Information Letters are issued for the upcoming calendar year to advise industry of deadlines for submission of their posting requests, publication of postings, and the actual sales dates which usually occur twice per month. The other two provinces follow a similar process , but their sales dates are less frequent.

Figure 7

Comparison of provincial land sales.



Taxation – Royalty Tax Credits and Workover Incentives

Alberta

Alberta Royalty Tax Credit

The Alberta Royalty Tax Credit (ARTC) provides oil and gas producers with a refundable tax credit equal to a percentage of the first $2 million in Crown royalty paid by each corporation. Effective January 1, 1995, the percentage of royalties rebated vary between 25% and 75% with the ARTC rate sensitive to the Royalty Tax Credit Reference Price (RTCRP), which includes a blend of oil and gas par prices. The ARTC rates are expressed as follows:

ARTC % = 75 when RTCRP $\leq \$100/m^3$

ARTC % = 75 – (2/40)* (RTCRP – 100) when $\$100 < RTCRP \leq \$140/m^3$

ARTC % = 73 – (48/70)* (RTCRP – 140) when $\$140 < RTCRP \leq \$210/m^3$

ARTC % = 25 when RTCRP $> \$210/m^3$

where:

RTCRP = (Oil%)*APP + ((Gas%) * GPP * GOC)

Oil % = The 3 year moving average of the percentage of Alberta conventional oil and gas royalties contributed by conventional oil.

APP = Average par price of oil for the previous quarter

Gas % = The 3 year moving average of the percentage of Alberta oil and gas royalties contributed by natural gas.

GPP = The gas par price in $/GJ for the latest available 3 months.

GOC = Gas to oil conversion ratio which is set at 79.64 GJ to 1 m.

The ARTC rate prescribed for the fourth quarter of 1998 is 73.68% based on a RTCRP of $126.49.

British Columbia

British Columbia does not have a royalty tax credit or a workover incentives program.

Saskatchewan

Saskatchewan Resource Credit

Crown royalty and freehold production tax rates are eligible for the Saskatchewan Resource Credit (SRC) reduction in effect since 1988. In general, for wells drilled before February 9, 1998, and for horizontal wells, the SRC is 1%. For vertical wells and new or expanded EOR and water flood projects after Feb 8, 1998, the SRC has been increased from 1% to 2.5%.

Workover Incentives

Old oil wells (pre-1974) may be reclassified as new oil wells for royalty/tax purposes if the operator undertakes an approved major workover to improve recoverability.

Manitoba

Manitoba offers a holiday volume for major workover of wells, see description under "Other Crude Oil Features".

Freehold Taxes

Crude Oil Freehold Mineral Tax

Alberta

The freehold mineral tax levied on the holder of a petroleum right is the aggregate of crude oil factors (COF) and solution gas factors (SGF) calculated for each well on the basis of production.

$$FMT = COF + SGF$$

$$COF = R \times M \times V \times T$$

where:

R = Prescribed tax rate = 0.269

$$M = \frac{(0.0833 \times Q)^2}{105.94} \text{ when } Q < 2{,}288.4 \text{ m}^3\text{/year}$$

$$M = \frac{Q}{4} - 228.84 \text{ when } Q \geq 2{,}288.4 \text{ m}^3\text{/year}$$

Q = Production (m^3/year)

V = Price ($/$m^3$)

T = % of total production attributable to the mineral right owner

$$SGF = R \times M \times V \times T$$

where:

R = Prescribed tax rate = 0.069

M = Annual solution gas production (e^3m^3/year)

V = Price ($/$e^3m^3$)

T = % of total production attributable to the mineral right owner

British Columbia

Freehold Production Tax is calculated and payable on a monthly basis in a manner very similar to the royalty calculation.

For example, the tax rate expressed as a percent is as follows:

- where monthly well/tract production ≤ 159 m^3

  Rate = 0.06 x Production

- where monthly well/tract production > 159 m^3

$$\text{Rate} = \frac{1575 + [20 \times (\text{Production} - 159)]}{\text{Production}}$$

Crude Oil Freehold Mineral Tax

Saskatchewan

The freehold tax on oil is derived by calculating the royalty rate according to the Crown royalty formula for crude oil and subtracting a production tax factor (PTF).

PTF = 6.9 for old oil
= 10.0 for new oil
= 10.0 for third tier oil

The intent is to equalise after-tax netbacks from Crown and freehold production.

Eligibility of freehold oil wells for a volume-based tax reduction is determined in the same manner as the volume-based Crown royalty reduction.

Manitoba

Freehold lessees are subject only to that portion of the freehold tax levied on the operator's share of production.

The freehold lessor is responsible for that portion of the tax levied on the royalty share of production. The freehold tax on crude oil is calculated based on the monthly production rate and oil classification (old, new, incentive and holiday oil).

T = Tax rate as % of P
P = Production (m^3/month)

Old Oil

T = 0, when $P \leq 20$
= $[(0.43 \times P) - 8.24]$, when $20 < P < 65$
= $[42.76 - (1{,}500 / P)]$, when $P \geq 65$

New Oil

T = 0, when $P \leq 36$
= $[(0.23 \times P) - 8.11]$, when $36 < P < 65$
= $[19.59 - (820 / P)]$, when $P \geq 65$

Third Tier Oil

T = 0, when $P \leq 46$
= $[11 - (465 / P)]$, when $P > 46$

Incentive Oil

T = 0, when $P \leq 56$
= $[9.27 - (510 / P)]$, when $P > 56$

Holiday Oil

T = 0, for all volumes

Natural Gas Freehold Mineral Tax

Alberta

The freehold mineral tax levied on the holder of a natural gas right is the aggregate of field gas factors (FGF) and gas well condensate factors (GWCF) calculated for each well on the basis of production.

FMT = FGF + GWCF

FGF = R x M x V x T when ADP ≥ 16.9 e^3m^3/day
FGF = M x V x A x T when ADP < 16.9 e^3m^3/day

where:

ADP = Average daily production
R = Prescribed tax rate = 0.069
V = Value ($/$e^3m^3$)
M = Annual field gas production (e^3m^3/year)
T = % of field gas recovered attributable to the mineral right owner
A = $R - \{[(R - 0.01) \times (16.9 - ADP)^2] / (16.9)^2\}$

GWCF = R x M x V x T

where:

Q = Production (m^3/year)
R = Prescribed tax rate = 0.269

M = $(0.0833 \times Q)^2 / 105.94$ when Q < 2,288.4 m^3/year
M = (Q / 4) – 228.84 when Q ≥ 2,288.4 m^3/year

V = Price ($/$m^3$)
T = % of total production attributable to the mineral right owner

British Columbia

The Freehold Production Tax is calculated and payable on a monthly basis in a manner very similar to the royalty calculation.

The tax rate expressed as a percent is as follows:

Conservation Gas:

- where P ≤ $50/$e^3$ m^3
  rate = 5%
- where P > $50/$e^3$ m^3
  rate = [245 + 9 x (P – 50)] / P

Non-Conservation Gas:

- where P ≤ $50/$e^3$ m^3
  rate = 9%
- where P > $50/$e^3$ m^3
  rate = [460 + 15 x (P – 50)] / P

Where P is the Reference Price defined as the greater of the selling price at plant inlet or the Posted Minimum Price (PMP).

Liquids Rate = 12.25%
Sulphur Rate = 10.25%

Natural Gas Freehold Mineral Tax

Saskatchewan

The freehold tax on natural gas is derived as for crude oil, by calculating the royalty rate according to the Crown royalty formula for natural gas and subtracting a production tax factor (PTF).

PTF = 6.9 for old gas
= 10.0 for new gas

The intent is to equalise after-tax netbacks from Crown and freehold production.

Eligibility of freehold gas wells for a volume-based tax reduction is determined in the same manner as the volume-based Crown royalty reduction.

Manitoba

Freehold lessees are subject only to that portion of the freehold tax levied on the operator's share of production. The freehold lessor is responsible for that portion of the tax levied on the royalty share of production.

The freehold tax is calculated as 1.2 % of the volume consumed or sold off the location.

Corporate Taxes

Federal Taxes

The net federal corporate income tax rate (after the 10% abatement for income taxes levied by the provinces) is 28%. A federal surtax levied at 4% of tax owed is applicable to corporations for an indefinite period. Corporations are generally allowed deductions for amounts paid out to earn income, including operating and lifting costs, capital cost allowance, interest expense, exploration and development expense, general and administrative expense and, in some cases, earned depletion. Deductions cannot be claimed for provincial royalties and freehold taxes paid.

Large corporations are assessed an additional tax of 0.225% on taxable capital employed in Canada less a capital deduction of $10 million. This tax may be credited against the federal surtax. Capital cost allowance provides a deduction against income for depreciating property. Many classes of depreciable property exist, the most relevant being Class 41 for oil and gas equipment. Class 41 allows a 25% write-down of equipment on a declining balance basis.

Corporations are also allowed a Resource Allowance deduction for income tax purposes. The Resource Allowance is a notional allowance in lieu of deduction of provincial royalties and freehold mineral taxes. The deduction is equal to 25% of taxable net resource profits computed as gross revenue (including production royalties receivable and deemed income in B.C.) less the sum of: operating and lifting costs, production royalties paid or payable, general and administrative expenses related to production, deductible Crown lease rentals, and capital cost allowances in respect of production assets. The Resource Allowance does not reduce the tax saving advantages related to the exploration and development expenditures discussed above. Resource Allowance not claimed in the current year cannot be carried forward.

Exploratory and development expenses are grouped into one of three pools: Canadian Exploration Expense (CEE)[1]; Canadian Development Expense (CDE)[2]; and Canadian Oil and Gas Property Expense (COGPE)[3]. The CEE balance of exploration expenditures must be fully deducted against income with any unclaimed portion carried forward indefinitely. Up to 30% of the CDE balance and up to 10% of the COGPE balance can be applied against income.

Manufacturing and Processing (M&P) Income (Gas Plants)

Since January 1, 1994, M&P income is eligible for a 7% reduction from the general tax rate, reducing the tax rate on manufacturing profits from 28% to 21%. M&P revenue must be at least 10% of the company's gross revenue to qualify for the credit. Oil and gas well operation and extraction are excluded from the M&P category, while operation of a gas plant is included. Gas plant income would include income from custom processing, processing on purchased gas and the difference between sales value and royalty value (sales value less a gas cost allowance calculated in a similar manner to the gas cost allowance for processing royalty volumes) for the producers' own gas. There is no Resource Allowance deduction from M&P income.

Small Business Deduction

Canadian Controlled Private Corporations (CCPC's) may deduct 16% of a maximum of $200,000 net income. This effectively reduces the rate on the first $200,000 from 38% to 22% (before provincial abatement).

[1] **CEE:** includes geological, geophysical, geochemical, drilling and completion expenses, cost of building a temporary access road or preparing a site for the well.

[2] **CDE:** includes expenses incurred in drilling or converting a well for the disposal of waste liquids, injection of water, gas or other substances, monitoring fluid levels or pressure changes, drilling for water or gas for injection, drilling & completing a well after the commencement of production or drilling & completing a well, building a temporary access road or preparing a site for the well to the extent that the expense is not a Canadian exploration expense.

[3] **COGPE:** includes the cost of any right, licence or privilege to explore or drill for petroleum, natural gas or related hydrocarbons, the cost of any oil or gas well, and rental or royalty.

Federal Taxes

Example of Simplified Tax Calculation Format

Gross Revenue
- – Operating & Lifting Costs
- – Non-Crown Royalty
- – General & Administrative Expense
- – Capital Cost Allowance
- – Interest Expense
- – Exploration & Development Expense
- – Resource Allowance
- = **Net Income**
- * Tax Rate

= Tax Payable

Gross Revenue
- – Operating & Lifting Costs
- – Non-Provincial Production Royalties Paid or Payable
- – General & Administrative Expense
- – Crown Lease Rentals on Non-producing Properties
- – CCA

= Net Resource Profits

Non-producing lease rentals are deductible at the rate of $2.50/ha for federal tax purposes.

Tax Rate = (38% – 10% provincial tax abatement + 3% federal surtax)

Common CCA Classifications

Class 1	4%	Pipeline manufacturing & distributing gas plant equipment.
Class 2	6%	As in Class 1, but acquired before 1988 – pursuant to an obligation in writing entered into before June 18, 1987 – that is a building, structure, plant facility or other property where the property was under construction by or on behalf of the taxpayer on June 18, 1987; or – that is machinery or equipment that is a fixed and integral part of property under construction by or on behalf of the taxpayer on June 18, 1987.
Class 10	30%	As in Class 41, but before 1987 and after 1979.
Class 29	50%	As in Class 39, but before 1987
Class 39	30%	Manufacturing & processing plant and equipment or oil or water storage tank after 1987.
Class 41	25%	Gas or oil well equipment Property acquired after 1987 that is designed principally for the purpose of: – determining the existence, location, extent or qualify of accumulations of petroleum or natural gas, property acquired after 1980 to be used in the processing of heavy crude oil.

Provincial Taxes

Alberta

Basic Corporate Tax

The current rate is 15.5 % of the amount taxable in Alberta where:

The royalty tax deduction can only reduce the tax to zero. Unused deductions can be carried forward.

Alberta Taxable Income = (Canadian Taxable Income – Royalty Tax Deduction) *(Alberta Allocation Factor)

Royalty Tax Deduction = (Crown Royalties and Freehold Mineral Tax paid but not allowed as a deduction for federal income taxes) – (25 % Resource Allowance)

Alberta Allocation Factor = $\frac{\text{Taxable income in Alberta}}{\text{Taxable income in Canada}}$

Manufacturing and Processing (M&P) Corporate Tax

The corporate income tax rate is 14.5 % for large manufacturers and processors.

Small Business Corporate Tax

The corporate tax rate is 6 % for firms that qualify as small businesses.

British Columbia

Basic Corporate Tax

The current rate applicable to the first $200,000 of active business income less the royalty tax rebate is 10 %. The rate applicable to taxable income over $200,000 is 16.5 %. The royalty tax rebate is the disallowed Crown royalty less the 25 % Resource Allowance. The rebate can either increase or decrease the tax on a corporate basis.

Provincial Taxes

Saskatchewan

Basic Corporate Tax

The current rate is 17% of taxable income earned in Saskatchewan less the royalty tax rebate. The small business rate is 8%.

The royalty tax rebate is the royalties/taxes less the 25% Resource Allowance. The rebate cannot increase the tax. Unused deductions can be carried forward.

Corporate Capital Tax Surcharge

Large resource corporations are assessed a corporation capital tax surcharge, which is equal to the difference between the existing corporation capital tax liability and 3.6% of a corporation's value of Saskatchewan resource sales. Saskatchewan's fiscal regime incorporates a deduction of up to $99,000 per year from the Corporate Capital Tax Surcharge for resource corporations whose assets total less than $100 million.

Small Business Deduction

Effective January 1, 1995, the small business corporate income tax rate was reduced to 8.0% from 8.5%.

Manitoba

Basic Corporate Tax

The basic corporate tax rate is 17% of taxable income earned in Manitoba.

Small Business Corporate Tax

The corporate tax rate is 10% for firms that qualify as small businesses.

For Further Information: Alberta

Alberta Resource Development

Visit the Resource Development website at: www.resdev.gov.ab.ca

Information Centre/Library

9945 – 108 Street
Edmonton, Alberta T5K 2G6
Phone: (780)427–7425
Fax: (780) 427–3198
E-mail: Energy.Library@gov.ab.ca

801 – 6 Avenue SW
Calgary, Alberta T2P 3W4
Phone: (403) 297–6324
Fax: (403) 297–2576

Mineral Tenure and Freehold Tax Branch

Information Letters, Crown Land Sales, Agreements, Well Licenses

Phone: (780) 427–7749
Fax: (780) 422–1123

Petroleum and Other Royalties Branch

Crude Oil, Oil Sands, Coal, Other Minerals, Oil Holidays and Relief

Phone: (780) 427–8050
Fax: (780) 422–0382

Gas Royalty Branch

Gas Royalty, Cost Allowances, Gas Holidays

Phone: (780) 427–2962
Fax: (780) 427–3334

Royalty and Tenure Branch

Fiscal Regimes Publication, Economic Analysis and Program Review

Phone: (780) 427–2964
Fax: (780) 422–0975

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Main Floor, McDougall Centre
455 – 6th Street SW
Calgary, Alberta T2P 4E8
Phone: (403) 297–6251
Fax: (403) 297–8450

Alberta Treasury, Corporate Tax

Alberta Royalty Tax Credit
Visit the website at: www.treas.gov.ab.ca/tra

Phone: (780) 427-3044
Fax: (780) 422-3770
Toll Free: 310-0000 then Phone or Fax number (in Alberta only)

Visit the following websites for more information about Alberta and its energy and mineral resources:

Government of Alberta at:

www.gov.ab.ca

Alberta Energy and Utilities Board at:

www.eub.gov.ab.ca

For Further Information: British Columbia

Department of Energy and Mines:
Visit the Energy and Mines website at: www.em.gov.bc.ca

Communications Branch
General information about the Ministry

PO Box 9324, Stn Prov Govt,
1810 Blanshard St.,
Victoria BC V8W 9N3
Phone: (250) 952–0606
Fax: (250) 952–0626/0627

Petroleum Lands Branch
Information Letters, Land Sales, Titles Administration

Phone: (604) 952–0340
Fax: (604) 952-0331

Resource Revenue Branch
Oil & Gas Royalties and Taxes

Phone: (604) 952–0195
Fax: (604) 952–0191

Queen's Printer
B.C. Statutes and Regulations
Visit the Queen's Printer website at: www.qp.gov.bc.ca

563 Superior Street
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For Further Information: Saskatchewan

Department of Energy and Mines
Visit the Energy and Mines website at: www.gov.sk.ca/enermine

1914 Hamilton Street
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Petroleum and Natural Gas Division
Petroleum Development, Engineering Services, Geology and Petroleum Lands,
Economic and Fiscal Analysis, Petroleum Statistics

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Resource Policy and Economics Division
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Office of the Queen's Printer
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Visit the Queen's Printer website at: www.qp.justice.gov.sk.ca

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E-mail: qprinter@justice.gov.sk.ca

For Further Information: Manitoba

Department of Energy and Mines
Visit the Energy and Mines website at: www.gov.mb.ca/em

1395 Ellice Avenue
Winnipeg, Manitoba R3G 3P2

Petroleum and Energy Branch
Phone: (204) 945–6577
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For Further Information: Nunavut Territory

Nunavut Planning Commission
Visit the Planning Commission website at: www.npc.nunavut.ca

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For Further Information: Northwest Territories

Department of Resources, Wildlife and Economic Development
Visit the Minerals, Oil, and Gas website at: www.gov.nt.ca/RWED/mog

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4th Floor Scotia Centre
5102 50th Avenue
P.O. Box 1320
Yellowknife Northwest Territories, X1A 2L9
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For Further Information: Yukon Territory

Department of Economic Development
Visit the Economic Development website at:www.economicdevelopment.gov.yk.ca

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209–212 Main Street,
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