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

Alberta Energy

Markets, Supply & Industry Analysis Division
Supply & Royalty Policy Branch

November 1991

Publication Number: T/249
ISBN: 0-86499-848-1

FOR ADDITIONAL INFORMATION OR COPIES OF THIS REPORT, CONTACT:

Director
Supply & Royalty Policy Branch
Markets, Supply & Industry Analysis Division
Alberta Energy
Petroleum Plaza, North Tower
5th Floor, 9945 - 108 Street
Edmonton, Alberta, Canada T5K 2G6

Telephone : (403) 427-7003
Fax : (403) 422-2548

TABLE OF CONTENTS

LIST OF FIGURES

SUMMARY

This report compares the fiscal regimes in British Columbia, Alberta, Saskatchewan, and Manitoba. It also discusses the Yukon and Northwest Territories.

The most notable changes in fiscal regimes from 1985 to 1988 were the end of the National Energy Program's discriminatory fiscal regime, reduction of federal taxes, reduction of royalty rates and the expansion of crude oil holiday programs to ameliorate the 1986 oil price crash in Alberta, and the introduction of tax and production holidays in other provinces. The changes generally reflected governments' willingness to forgo revenues in an effort to aid the oil and gas industry as it recovered from the National Energy Program, faced the 1986 price slump, and made the transition from a highly regulated market to a deregulated one.

Since 1988 the changes made have reflected the trends of consolidation and less government willingness to forgo revenues to support activity. Major changes are:

- Phase out of federal CEDIP and CEIP programs
- Introduction of a federal large corporations capital tax
- Expiration of natural gas holidays in British Columbia
- Expiration of exploration natural gas holidays in Alberta
- Phase out of old, and introduction of new, oil royalty holidays in Alberta
- Phase out of Manufacturing and Processing tax reductions in Alberta
- Restructuring of the Alberta Royalty Tax Credit from an ad hoc to a fixed term price sensitive program
- Temporary assistance to gas producers through ARTC adjustment following the Gulf War
- Changes to fiscal regimes to accommodate horizontal drilling in Saskatchewan and Manitoba, and for a trial period in Alberta
- Increases in provincial taxes in Alberta, British Columbia, and Saskatchewan

A comparison of fiscal regimes must recognize the differing scale and nature of oil and gas operations among the four provinces. Alberta accounts for 80-90% of Canada's oil and gas production, while British Columbia, Saskatchewan, Manitoba, and the Territories are much smaller producers.

This comparison of fiscal regimes does not take into account variations in exploration, drilling, and development costs or the variation in the frequency and size of hydrocarbon discoveries in each jurisdiction. Play economics differ for each province and would have to be taken into account to definitively compare the attractiveness of each province's oil and gas prospects.

Except where otherwise noted, all dollars are expressed in Canadian currency.

1. CROWN ROYALTIES
1.1 Conventional Crude Oil

B.C.

R% = Royalty rate
Q = Production (m^3/month)

R% = $[Q^2*100]/[K*Q]$, when $Q \leq C$
R% = $\{[A+B*(Q-C)]*100\}/Q$, when $Q>C$

Old Oil (pre-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 = 1 058
A = 23.9

B = Percent of incremental production
= 30%

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

Note on Alberta k and y factors:
* k and y factors are determined under the regulations. Current k and y factors are as follows: k = 0.846154 (for old oil)
y = 0.246154 (for new oil)

ALBERTA

R% = Royalty rate
Q = Production (m^3/month)

R% = $\{S+kS[(A-B)/A]\}*100/Q$ for old oil
R% = $\{S+yS[(A-B)/A]\}*100/Q$ for new oil

where:
S = the basic royalty in cubic metres

S = $Q^2/1271.28$
when $Q \leq 190.7$ m^3/month (1 200 bopm)

S = $[(Q-190.7)/4] + 28.6$
when $Q > 190.7$ m^3/month (1 200 bopm)

A = Par Price = Average wellhead price ($/$m^3$)

B = Select Price = $40.90/$m^3$ ($6.50/b)

k,y = a royalty factor set to make the royalty formula equal to the intent formula on the reference well

k,y* = $\{[(r\%*572.07)/123.95]-1\}/[(A-B)/A]$

r% = Royalty intent at a well reference rate of 572.07 m^3/month (3 600 bopm)

Old Oil (pre-April, 1974)
r% = $\{[0.2167*B] + [0.4*(A-B)]\} * 100/A$

New Oil (post-March, 1974)
r% = $\{[0.2167*B]+[0.27*(A-B)]\} * 100/A$
when $A \leq \$188.80/m^3$ ($30/b)

r% = $\{[0.2167*B]+[0.27*(188.80-B)] +[0.3*(A-188.80)]\} * 100/A$
when $A > \$188.80/m^3$ ($30/b)

1.1 Conventional Crude Oil (cont'd)

MANITOBA

R% = Royalty rate
P = Production (m^3/month)

R = (S*C)/P

where:

S = Base Crown royalty

S = $(P)^2/265$, when $P \leq 50$ m^3/month

S = 9.43 + [0.45*(P-50)], when $P > 50$ m^3/month

C = 1.0 for old oil (pre-April 1, 1974)
= 0.55 for new oil (post-March 31, 1974)

SASKATCHEWAN

R% = Royalty rate
MOP = Production (m^3/month)

R% = {K-[X/MOP]}-SRC to a minimum of 0%

where:

X = K*23.08

A = Average wellhead price of non-heavy oil ($/$m^3$)

B = Average wellhead price of heavy oil ($/$m^3$)

SRC = Saskatchewan Resource Credit of one percentage point

Old Oil (pre-1974)

K = 26 +{32.5*[(A-50)/A]}

New Oil (post-1973)

K = 19.5 +{26*[(A-50)/A]} for non-heavy oil

K = 13 + {19.5*[(B-50)/B]} for heavy oil

All wells producing at less than 1.6 m^3 (10 barrels) per day will receive "new oil" designation (as of January 1, 1991).

Heavy oil is defined as oil produced from the Lloydminister and Kindersley-Kerrobert heavy oil areas. All heavy oil is given new oil status.

1.1 Conventional Crude Oil (cont'd)

B.C.

Objective:

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

Old Oil

To take 40% of incremental production above 95 m^3/month as a percentage of total production.

New Oil

To take 30% of incremental production above 159 m^3/month as a percentage of total production.

Low Productivity Wells

Old oil wells producing at less than 95 m^3/month (600 bopm), and new oil wells producing at less than 159 m^3/month (1 000 bopm) benefit from lower royalty rates.

ALBERTA

Objective:

To determine a royalty share to be retained by the resource owner that is sensitive to well productivity, and crude oil price and vintage.

Old Oil

To take a royalty of 21 2/3% of the first \$40.90/m^3 (\$6.50/b) of the price, and 40% of the price in excess of \$40.90 m^3 at a well reference rate of 572 m^3/month (3 600 bopm).

New Oil

To take a royalty of 21 2/3% of the first \$40.90/m^3 of the price, 27% of the price between \$40.90 and \$188.80/m^3 (\$30/b), and to take 30% of the price above \$188.80/m^3 at a well reference rate of 572 m^3/month (3 600 bopm).

Low Productivity Wells

Wells producing at rates of less than 191 m^3/month (1 200 bopm) are subject to lower royalties.

<u>Comparison of Royalty Rates as Function of Price</u>
Old Oil: Alberta royalty rates are considerably lower than comparable rates for Saskatchewan; both regimes are price-sensitive. Royalty rates in Manitoba and B.C. do not respond to price; at a 159 m^3/month well rate (1 000 bopm), the B.C. royalty rate is lower than that of Manitoba.
New Oil: The Saskatchewan heavy oil regime exhibits the lowest royalty rate at prices under \$62/m^3 (\$10/b). Above this price and at a well rate of 159 m^3/month, the Alberta and B.C. regimes produce the lowest royalty rates of all the provinces (Figure 1).

MANITOBA

Objective:
To determine a royalty share to be retained by the resource owner that is sensitive to production and vintage.

Old Oil
To take 100 % of the base royalty.

New Oil
To take 55% of the base royalty.

Low Productivity Wells
No special allowance applies to low productivity wells.

SASKATCHEWAN

Objective:

To determine a royalty share to be retained by the resource owner that is sensitive to well productivity, and crude oil price and vintage.*

Old Oil
To take a royalty of 20% of the first \$50/m^3 (\$7.95/b) of the price, and 45% of the remainder at a well reference rate of 100 m^3/month (630 bopm).

New Oil
To take a royalty of 15% (non-heavy oil) or 10% (heavy oil) of the first \$50/m^3 of the price, and to take 35% (non-heavy oil) or 25% (heavy oil) of the price above \$50/m^3 at a well reference rate of 100 m^3/month (630 bopm).

Low Productivity Wells
Wells producing at rates less than approximately 23 m^3/month (145 bopm) are not subject to a royalty.

<u>Comparison of Royalty Rates as a Function of Productivity</u>
Old Oil: At a price of \$125.86/m^3 (\$20/b), royalty rates for Alberta and B.C. are similar throughout the range of production, and peak at about 39%. Royalty rates for Manitoba and Saskatchewan are also comparable, although no royalty applies in the case of Saskatchewan at a well rate below 23 m^3/month at this price. Rates under the Manitoba and Saskatchewan regimes peak at about 44%.
New Oil: For new oil, the Saskatchewan non-heavy crude regime produces the highest royalty rates, while the regime for heavy crude produces the lowest. Royalty rates under the Manitoba regime are similar to those of the Saskatchewan heavy regime at production levels above 23 m^3/month, and the maximum rates under both regimes are less than those of Alberta and B.C. (Figure 2).

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* Effective July, 1988 the calculated royalty rate is reduced by 1% to implement the Saskatchewan Resource Credit (SRC).

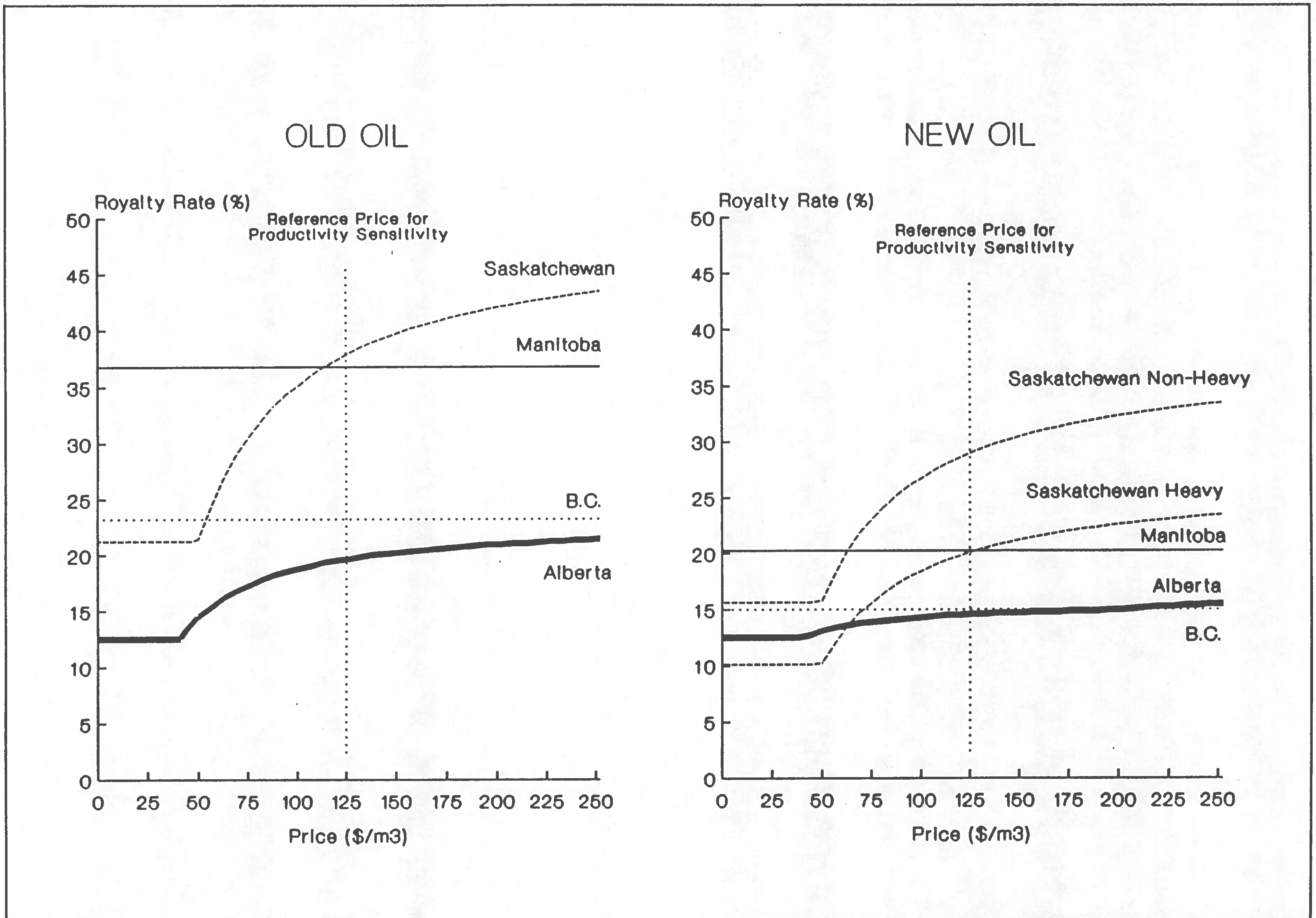

Figure 1 Comparison of B. C., Alberta, Saskatchewan and Manitoba Crude Oil Royalty Rates as a Function of Wellhead Price. Well Productivity = 159 m^3/month (1 000 bopm).

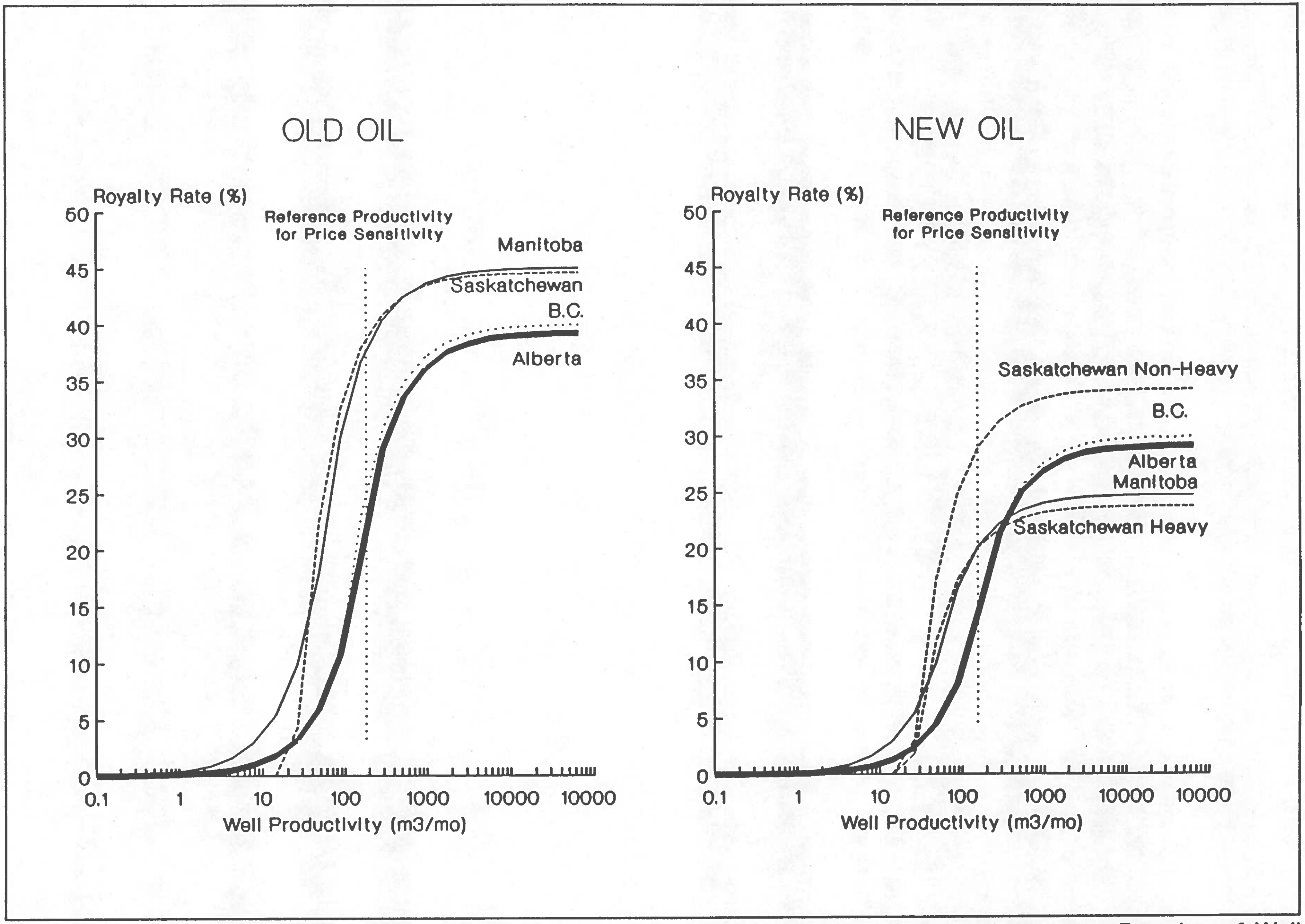

Figure 2 Comparison of B. C., Alberta, Saskatchewan and Manitoba Crude Oil Royalty Rates as a Function of Well Productivity. Wellhead Price = $125.86/m^3$ ($20/b)

1.2 Natural Gas

B.C.

R% = Royalty rate
P = Reference Price ($\$/10^3m^3$), the greater of Selling Price @ plant inlet or PMP (Posted Minimum Price)

Non-Associated Gas

R% = {[750 + 25(P-50)]/P}, with a minimum of 15% when P < $\$50/10^3m^3$

Conservation Gas

R% = {[400 + 15(P-50)]/P}, with a minimum of 8% when P< $\$50/10^3m^3$

ALBERTA

R% = Royalty rate
AMP = Average Alberta Market Price ($\$/10^3m^3$) established by the Minister in advance of each production month
Heat Content AMP = AMP $/GJ

Old Gas (pre-1974)

R% = 22%, when AMP ≤ $\$17.75/10^3m^3$ ($0.50/mcf)

R% = {390.50 + [40*(AMP-17.75)]}/AMP
when AMP > $\$17.75/10^3m^3$ ($0.50/mcf)

New Gas (post-1973)

R% = 22%, when AMP ≤ $\$17.75/10^3m^3$ ($0.50/mcf)

R% = {390.50 + [27*(AMP-17.75)]}/AMP
when AMP > $\$17.75/10^3m^3$ ($0.50/mcf)
and ≤ $\$71.00/10^3m^3$ ($2/mcf)

R% = {1 828.25 + [30*(AMP-71.00)]}/AMP
when AMP > $\$71.00/10^3m^3$ ($2/mcf)

Low Productivity Allowance (Old and New Gas)

R% = Rc-{[(Rc-5)*(16.9-ADP)^2]/(16.9)^2}
when P < 16.9 10^3m^3/day

where:

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

ADP = Average daily production (10^3m^3) over a month for a well

1.2 Natural Gas (cont'd)

MANITOBA

R% = Royalty rate
R% = 12.5% of monthly sales

SASKATCHEWAN

R% = Royalty rate

R% = [C*MGP]-SRC
when MGP ≤ 115.4 10^3m^3/month (135 mcf/day)

R% = {K-[X/MGP]}-SRC
when MGP > 115.4 10^3m^3/month (135 mcf/day)
to a minimum of 0%

where:

MGP = Marketable Gas Production (10^3m^3/month)

C = K/230.76

X = K*57.69

P = Average provincial fieldgate price ($/$10^3m^3$) as determined by the Saskatchewan Department of Energy and Mines

SRC = Saskatchewan Resource Credit of one percentage point

Old Gas (pre-October 1976)

K = 26 + {32.5*[(P-35)/P]}

New Gas (post-September 1976)

K = 19.5 + {26*[(P-35)/P]}

Gas Associated with Oil

R% = 0%

1.2 Natural Gas (cont'd)

B.C.

Objective:

To determine a royalty share to be retained by the resource owner that is sensitive to gas prices above $\$50/10^3m^3$. Effective November 1, 1990 there is a minimum price (PMP) for natural gas to be used in the calculation of the royalty rate and royalty payable.

Low Productivity Wells

There are no special allowances for low productivity wells.

ALBERTA

Objective:

To determine a royalty share of production to be retained by the resource owner that is sensitive to the prevailing market price and the vintage of the reserves, with adjustments for low productivity wells. The royalty volumes are valued at the greater of the selling price, or 80% of the prevailing Heat Content AMP. The gross unit royalty (R$) is calculated as:

R% = Royalty rate
F = Selling price ($/GJ)
R$ = R%*F, if F ≥ 0.8*Heat Content AMP
R$ = R%*0.8*Heat Content AMP, if F < 0.8*Heat Content AMP

Old Gas

To take 22% of the first $\$17.75/10^3m^3$ ($.50/mcf) of the price and 40% of the remaining price.

New Gas

To take 22% of the first $\$17.75/10^3m^3$ of the price, 27% of the price between $17.75 and $\$71/10^3m^3$ ($0.50 and $2/mcf), and to take 30% of the remaining price.

Low Productivity Wells

Wells producing at 16.9 10^3m^3/day (600 mcf/day) or less are entitled to an allowance which reduces royalty rates to as low as 5%. This allowance does not apply to solution or associated gas.

<u>Comparison of Natural Gas Royalty Rates as a Function of Price</u>
The Manitoba regime, which is not sensitive to either prices or production, generates the lowest royalty rate of all the provinces at a flat rate of 12.5% of sales. Royalty rates produced by the Alberta regime exceed those for B.C. and Manitoba, but are less than those of Saskatchewan over most of the price range (Figure 3).

1.2 Natural Gas (cont'd)

MANITOBA

Objective:

To take 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.

SASKATCHEWAN

Objective:

To determine a royalty share to be retained by the resource owner that is sensitive to well productivity, and natural gas price and vintage.*

Old Gas

To take 20% of the first $35/10^{3}m^3 ($1/mcf) of the price and 45% of the remaining price at a well reference rate of 250 10^{3}m^3/month (292 mcf/day).

New Gas

To take 15% of the first $35/10^{3}m^3 of the price, and 35% of the remaining price at a well reference rate of 250 10^{3}m^3/month.

Low Productivity Wells

There is no special allowance for low productivity wells.

<u>Comparison of Natural Gas Royalty Rates as a Function of Productivity</u>
Neither the B.C. regime nor the Manitoba regime is sensitive to production. At a price of $70.99/m^3 ($2/mcf), the Manitoba royalty rate (12.5%) is less than the B.C. rate (18%). Royalty rates generated by the Alberta regime at this price are less than those of Saskatchewan for production levels above 80 10^{3}m^3/month (about 93 mcf/d) (Figure 4).

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*Effective July, 1988 the calculated royalty rate is reduced by one percentage point to implement the Saskatchewan Resource Credit (SRC).

1.2 Natural Gas (cont'd)

B.C.

Producer Cost of Service Allowance
All gas producers are eligible to receive the producer cost of service allowance (PCOS) for field gathering, compression and conservation. It is a fixed rate deduction from gross natural gas royalty. The rates vary according to H_2S content, field facilities, and geographic location (See table below).

Gas Cost Allowance
Producers with natural gas processed at plants not owned by Westcoast Energy Company Ltd. are entitled to deduct a gas cost allowance (GCA) against royalties. The gas cost allowance is determined in a manner similar to that used in Alberta, with the allowance calculation based on plant flow-through volumes.

PRODUCER COST OF SERVICE ALLOWANCE RATE TABLE

Category	$/10³m³ of Raw Gas Delivered Area "D" $H_2S \leq 1\%$	Area "D" $H_2S > 1\%$	Other Areas $H_2S \leq 1\%$	Other Areas $H_2S > 1\%$
Gas Wells:				
Field Gathering and Dehydration	$5.00	$11.00	$4.00	$5.00
Field Compression	8.00	9.00	5.00	5.00
Maximum Claim	13.00	20.00	9.00	10.00
Oil Wells:				
Conservation of Conservation Gas	16.00	16.00	16.00	16.00

The designation of area "D" is as follows:
From a commencement point of Latitude 54°00' and Longitude 120°00', northwest along the Rocky Mountain watershed to Latitude 55°35', east to Longitude 120°00', south to Latitude 55°25', east to Longitude 120°00' and south to the commencement point.

ALBERTA

Gas Cost Allowance

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

1. Operating costs
2. Capital cost allowance, and
3. A 15% return on capital before tax.

The annual GCA royalty deduction is calculated as the portion of annual allowable GCA costs attributable to the non-freehold share of the volumes produced, multiplied by the effective gross royalty rate at the facility for all products. The actual deduction is the lesser of the calculated deduction or 95% of the gross royalty. Estimates of GCA are allowed as deductions from monthly royalty payments.

1.2 Natural Gas (cont'd)

MANITOBA

Gas Cost Allowance

No gas cost allowance.

SASKATCHEWAN

Gas Cost Allowance

Saskatchewan producers receive a deemed gas cost allowance of $\$5/10^3m^3$ on old raw gas and $\$10/10^3m^3$ on new raw gas. This allowance is in recognition of costs incurred in gathering and compressing the Crown's share of natural gas. The costs of processing gas are excluded from the allowance because the vast majority of natural gas is marketed in a raw (unprocessed) state.

Natural gas royalty rates are calculated on the natural gas price before deduction of the gas cost allowance.

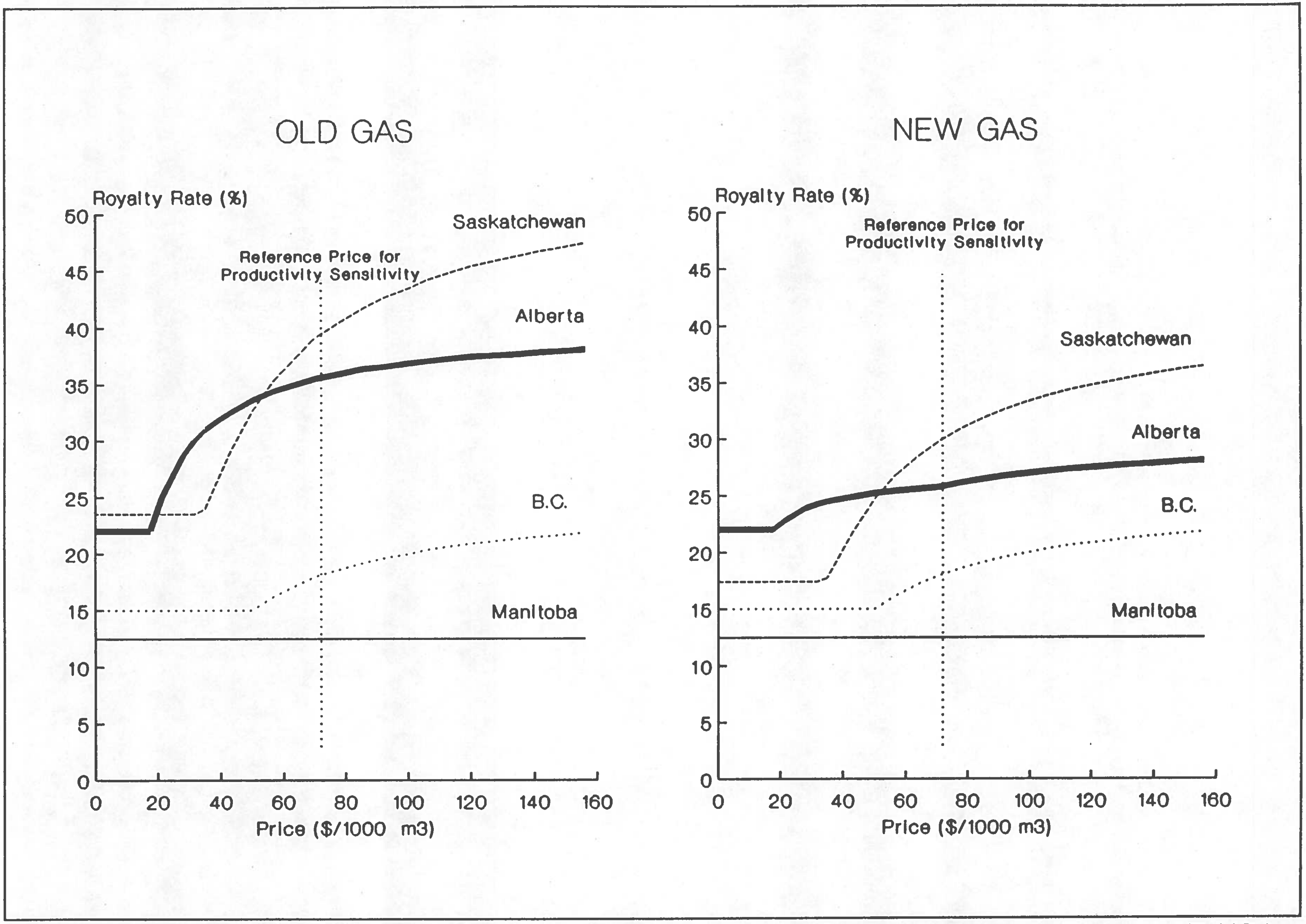

Figure 3 Comparison of B. C., Alberta, Saskatchewan and Manitoba Natural Gas Royalty Rates as a Function of Field Price. Well Productivity = 1295 10^3 m^3/month (1200 mcf/d).

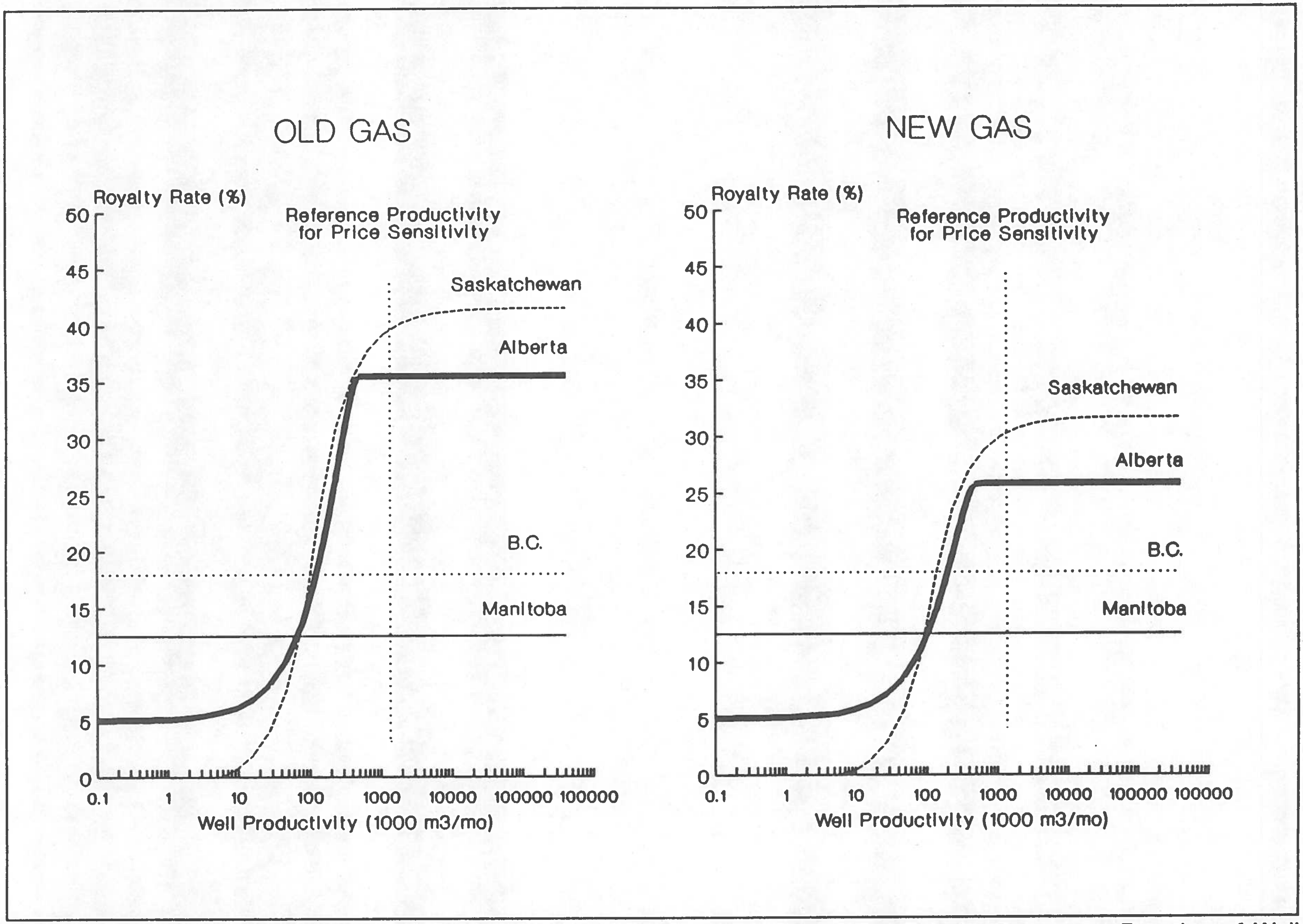

Figure 4 Comparison of B.C., Alberta, Saskatchewan and Manitoba Natural Gas Royalty Rates as a Function of Well Productivity. Field Price = $70.99/10^3 m^3 ($2/mcf).

1.3 Natural Gas Byproducts

B.C.

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

No royalty is paid on sulphur obtained from gas processed by Westcoast Energy for Can West Gas Supply Inc. Instead, Westcoast Energy sells the sulphur and the net proceeds become part of the average price Can West pays for contracted natural gas.

Where gas is not processed by Westcoast Energy, or where Westcoast Energy processes gas for other marketers, a flat rate royalty of 16 2/3% applies on sulphur.

ALBERTA

Pentanes Plus:

R% = Royalty rate
R% = {[22*B] + [C*(F-B)]}/F

where:

F = Average selling price ($\$/m^3$)
B = Select Price = $\$40.90/m^3$ ($6.50/b)

Old Pentanes Plus (pre-1974)

C = 50

New Pentanes Plus (post-1973)

C = 35

Objective

To take 22% of the first $\$40.90/m^3$ of the price and 50% and 35% of the price in excess of $\$40.90/m^3$ 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.

1.3 Natural Gas Byproducts (cont'd)

MANITOBA

Royalties and taxes are not levied separately on natural gas byproducts. The levy on raw natural gas encompasses byproducts.

SASKATCHEWAN

The majority of natural gas byproducts are derived from associated gas, which is not subject to a direct royalty or tax. Byproducts contained in natural gas that is marketed in a raw (unprocessed) state are subject to the natural gas royalty.

1.4 Nonconventional Crude Oil

Oil Sands Royalty

B.C., Saskatchewan and Manitoba have no royalty regimes for oil sands. Alberta has regimes for the two mining projects, Suncor and Syncrude, and the Cold Lake regime for commercial in situ projects. Experimental projects as designated by the ERCB have separate royalty regimes.

Suncor

Alberta receives a percentage of either production or net revenues according to the following schedule:

From July 1, 1987 to December 31, 1991: the greater of 2% of gross production or 15% of net revenues.
After December 31, 1991: the greater of 5% of gross production or 30% of net revenues.

Syncrude

Alberta receives a royalty of 50% of net revenue. Net revenue is calculated as:

Deemed Gross Revenue
- Allowed Operating Costs
- Deemed Interest Expense
- Amortization of Capital Expenditures
- <u>Loss Carry Forwards (if any)</u>
= Net Revenue

The deemed interest expense consists of 8% simple interest per annum based on 75% of average capital employed. The amortization of capital expenditures commenced in 1984 and encompasses all pre-production and ongoing capital over an assumed life commencing on the first day of the month such expenses were incurred (1984 if the expenses were incurred earlier) and ending in 2004 on a remaining useful life basis.

Between January 1, 1983 and December 31, 1987 capital expenditures (termed "special capital costs") qualify for a 100% write-off in the year incurred, thereby deferring royalties. This royalty adjustment was implemented to encourage Syncrude to expand plant capacity. Royalty benefits occur only if expenditures exceed previously agreed-upon levels. A minimum royalty clause ensures that the minimum joint venture payment would be the lesser of: 5% of gross revenue, or 50% of the net revenue that would have been payable without the implementation of the special capital costs write-off.

Alberta has an option to take a 7.5% gross revenue royalty in place of the 50% net revenue royalty. This option can only be exercised once. Therefore, once the Province opts for a 7.5% gross revenue royalty it cannot revert to a 50% net revenue royalty.

1.4 Nonconventional Crude Oil (cont'd)

Commercial In Situ Production

Typically, the fiscal terms applicable to commercial in situ thermal projects are known as the Cold Lake regime because they were first applied to the Esso Cold Lake Project. The royalty consists of a 1% royalty on gross revenue at startup, increasing by 1% every 18 months to 5%. The royalty remains at 5% until payout at which point it converts to 30% of net profit or 5% of gross revenue, whichever is greater.

Net profit is calculated as:

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

Operating costs and capital costs receive 10% and 1% uplifts respectively to recognize indirect expenses.

Unrecovered costs are escalated by a 10% return allowance. Royalty payout is attained when cumulative gross revenue exceeds cumulative operating costs, capital costs, gross royalty and return allowance.

Experimental Projects

Experimental projects approved by the ERCB receive a flat royalty rate of 5% of production.

1.5 Oil & Gas Royalty Regulations in Yukon and Northwest Territories

Under the Canada Petroleum Resource Act (CPRA) royalty regulations, which use the Alberta Cold Lake royalty regime as a starting point, the royalty consists of a 1% royalty or gross revenue at startup, 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 recognize indirect expenses. Allowed capital costs incurred before the approval of the development plan receive a 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.

1.6 Petroleum and Natural Gas Rights

The total revenue received by a Province from the giving up of resource rights generally has two major components, revenue from the sale of the right to produce the oil or gas, and revenue from royalties on production from that lease.

Sections 1.1 to 1.4 have dealt with the royalty aspect. This section compares revenues received for the sale of rights for conventional oil and gas from Saskatchewan, Alberta and B.C. from 1986 to 1990.

The revenue from sales of mineral rights comes from the sale of these rights by public tender. 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 similar despite differences in royalty rates and incentive programs.

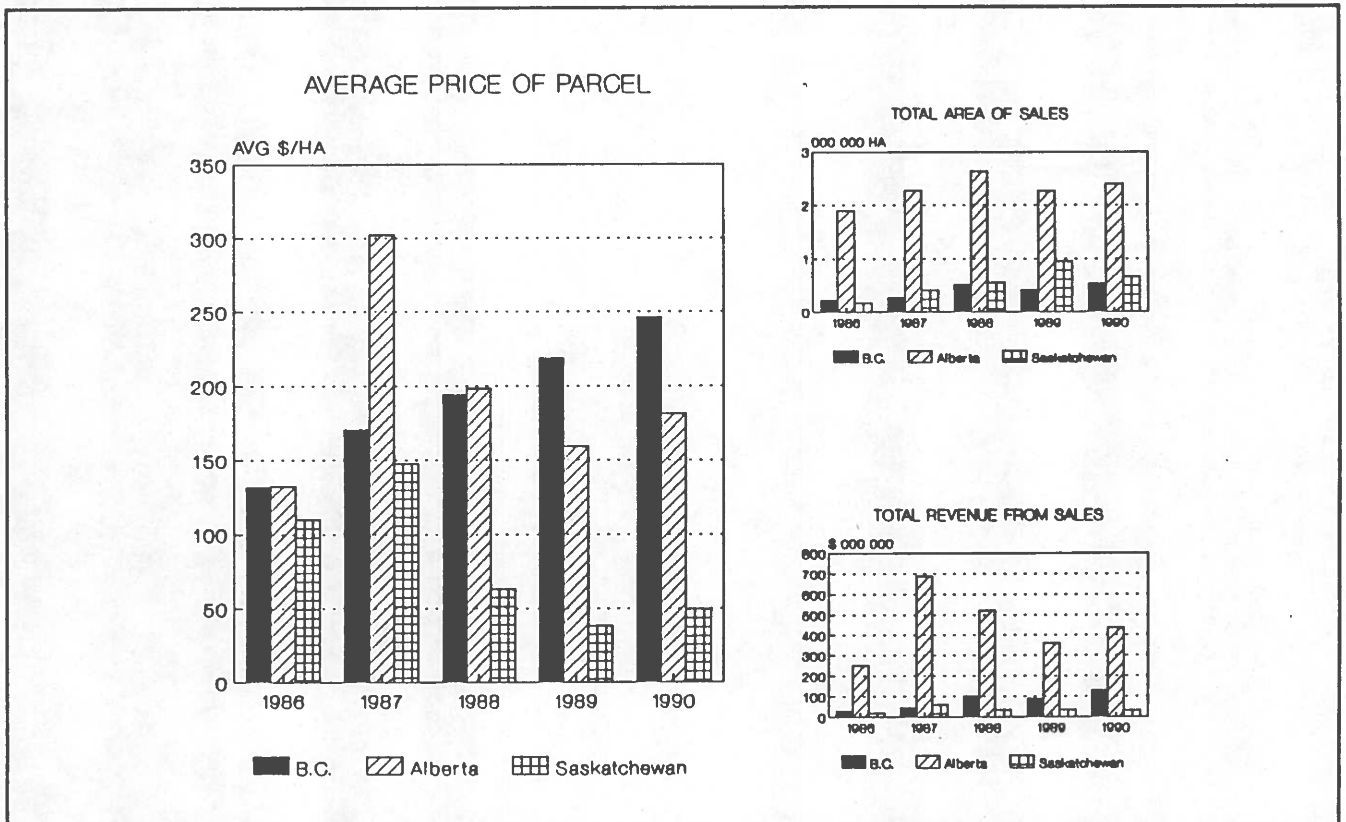

Figure 5 Comparison of British Columbia, Alberta and Saskatchewan Land Sales. Source: Nickle's Oil and Gas Statistics Quarterly.

2. INCENTIVES
2.1 Crude Oil Royalty Holidays

B.C.

Discovery Oil Royalty Holiday

Oil produced from a new pool discovery well completed after June 30, 1974 is royalty exempt for the first 36 producing months.

All benefits from holidays that were given to wells drilled under the various Crude Oil Royalty Holiday Programs will expire on December 31,1991.

ALBERTA

Exploration Oil Royalty Holiday

Qualifying Oil Royalty Holiday
Exploratory wells located more than 2.4 kilometres from the nearest well capable of production from the same zone qualify for an exploratory holiday.

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. Wells eligible for the horizontal well royalty reduction will be eligible, but will then be required to forgo the horizontal well benefit.

Qualifying Period and Benefits
Wells in the Plains area will qualify for a 24 production-month holiday if they are spudded after 31 October 1991 and before 1 April 1992. Wells spudded after 31 March 1992 and prior to 1 April 1993 will qualify for a 12 production-month holiday.

Wells in the **Northern and Foothills** areas, where the Province restricts access for environmental reasons, will qualify for a 24 production-month holiday if they are spudded after 31 October 1991 and before 1 April 1993. The qualifying period for drilling will end on 31 March 1993 and the holiday benefits must be taken prior to 1 April 1996.

Maximum Benefit
The maximum value of the oil royalty volumes granted a holiday will be $1 million for any individual well. For the purposes of the holiday cap, the oil will be valued at Par Price.

ALBERTA

Development Oil Royalty Holiday

Qualifying Types of Wells
All development wells drilled except for those which are eligible for the Exploration Oil Royalty Holiday or Non-Qualifying Wells.

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 will be specifically excluded. Wells eligible for the horizontal well royalty reduction well be eligible, but will then be required to forgo the horizontal well benefit.

Qualifying Period and Benefits
Wells qualify for a 12 production-month holiday if spudded after 31 October 1991 and before March 31, 1993. The program will terminate on March 31, 1993. The qualifying period for drilling will end on 31 March 1993 and the holiday benefits must be taken prior to 1 April 1996.

Maximum Benefit
The maximum value of the oil royalty volumes granted a holiday will be $400,000 for any individual well. For the purposes of the holiday cap, the oil will be valued at Par Price.

Reactivated Oil Well Holiday

Qualifying Type of Wells
All oil wells which have been continuously inactive since 31 August 1990 and inactive on 31 October 1991 will be eligible. An oil well will be a well than when reactivated initially produces crude oil with a gas to oil ratio of less than 1800:1. Gas wells will not be eligible.

Non-Qualifying Wells
Wells eligible for benefits under another royalty reduction program will

ALBERTA

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.

Qualifying Period and Benefits
All qualifying wells which are reactivated after 31 October 1991 and before 1 April 1993, will have royalties waived on oil produced during the sixty calendar months following the date of reactivation.

Maximum Benefit and Time
The maximum royalty holiday per well will be the royalty on 25,000 barrels of production. A well reactivated in the last eligible month, March 1993, will have a royalty holiday on oil produced prior to 1 April 1998.

New Oil Certification

The administrative process is simplified through the removal of the application requirement for "new" status.

Qualifying Type of Wells
- Oil wells drilled after 31 October 1991.
- Oil wells eligible under the Reactivated Well Holiday program.
- Oil wells shut-in as of 31 October 1991, reactivated prior to 1 April 1993, and inactive for a continuous period of one year.

Existing provisions for converting "old" oil wells to "new" status after a three year shut-in period will be discontinued. An oil well will be a well that initially produces crude oil with a gas to oil ratio of less than 1800:1 at the time of first production or reactivation. Gas wells will not be eligible.

Benefits
All eligible wells will be certified as "new" oil wells without making application for new status.

2.1 Crude Oil Royalty Holidays (cont'd)

MANITOBA

Incentive Drilling Program

Wells drilled between January 1, 1987 and January 1, 1992 qualify for royalty/tax free production. The holiday volume is sensitive to price, well location, depth, producing formation and qualifying credits from previous dry holes. The maximum volume is 10 000 m^3 or five years of production, whichever occurs first.

$VT = V_k + V_l + V_f + VT_i * ti$

where:

VT = Total royalty holiday volume (m^3)

V_k = Distance factor volume (maximum 5000 m^3) = D*A+B

D = Distance from nearest well (km)

A = 1.7 P + 230

B = 3130 - 13.6 P

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

V_l = Length factor volume (with TL>1000 m)

V_l = 4 * TL - 4000 when D≤1.6 km

TL = Total length (m)

IL = Incremental length (m) = greater of (TL - TL (deepest well within 1.6 km) or (TD - 1000)
= 0 if not greater than 30 m

SASKATCHEWAN

Exploratory Oil Royalty/Tax Holiday

Exploratory wells (located at least 3 km from the nearest oil well or producing from geological systems below all other wells within 3 km) qualify for a three-year holiday. Deep exploratory wells meeting this distance requirement, drilled into a geological system older than Mississippian (other than the Bakken formation) and capable of producing oil from depths greater than 1 700 m qualify for a five-year holiday.

Development Oil Royalty/Tax Holiday

Eligible development wells and incremental oil from new or expanded waterflood projects qualify for a two year royalty/tax holiday which is later phased down to one year on a monthly basis in accordance to an established schedule (see next page). Eligibility is restricted to wells drilled into drainage units where previous drilling has not occurred or where drilling has resulted in dry or abandoned wells. Wells that do not qualify for two-year holidays may be eligible for a one-year holiday. Deep development wells drilled into a geological system older than Mississippian (other than the Bakken formation) and capable of producing oil from depths greater than 1 700 m qualify for a three-year holiday.

2.1 Crude Oil Royalty Holidays (cont'd)

MANITOBA(cont'd)

V_f = Formation factor volume (m^3) as in table below:

Formation	Formation Factor Volume (Vf)
Bakken	500
Nisku	1000
Duperow	1400
Dawson Bay	1800
Winnipegosis	2200
Ashern	2300
Interlake	3100
Stonewall	3200
Stony Mountain	3400
Red River	4400
Winnipeg	4600
Deadwood	5000

$VT_i * t_i$ = qualifying dryhole volume as modified by the time reduction factor excluding volumes less than 1600 m^3 for any dry hole.

t_i = time reduction factor

t_i = 0.5 when the dry hole was drilled within the previous year

t_i = 0.2 when the dry hole was drilled more than 1 year but less than 2 years previous.

t_i = when the dry hole was drilled more than 2 years previous.

SASKATCHEWAN(cont'd)

	Heavy Oil Area	Non-Heavy Oil Area
	24 months from Jul 1/88-Dec 31/91	24 months from Jul 1/88-Dec 31/90
	In 1992	In 1991
January	24 months	24 months
February	23 months	23 months
March	22 months	22 months
April	21 months	21 months
May	20 months	20 months
June	19 months	19 months
July	18 months	18 months
August	17 months	17 months
September	16 months	16 months
October	15 months	15 months
November	14 months	14 months
December	13 months	13 months
	12 months thereafter	12 months thereafter

2.2 Natural Gas Royalty Holidays

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Deep Gas Royalty Holiday Program (DGRHP)

Effective June 1, 1985, 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 m. The drilling spacing unit must be wholly outside the deep gas pools as defined by the ERCB.

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 m. The royalty holiday applies until the value of the natural gas and byproducts 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 ($000)	Incremental Value ($/metre)
2500	0	1000
3000	500	1000
3500	1000	1000
4000	1500	1300
4500	2150	1300
5000	2800	1600
5500	3600	-

Note: B.C., Saskatchewan and Manitoba do not offer natural gas royalty holidays.

2.3 Enhanced Oil Recovery Relief

B.C.

Incremental oil production from either an approved experimental tertiary recovery project or a commercial tertiary recovery project is subject to a royalty agreement established under Section 93 of the B.C. Petroleum and Natural Gas Act.

ALBERTA

Section 11 of the Alberta Petroleum Royalty Regulations allows the operator of an approved tertiary recovery scheme to deduct approved costs from tertiary revenues before calculating royalties.

Approved costs are costs incremental to a suitable secondary recovery scheme, and are approved by the Department of Energy.

Tertiary revenues are determined by a tertiary factor calculated by the Department, which deems a portion of the oil recovered from the project as incremental tertiary.

Tertiary (t) factor for a EOR project is:

$$\text{'t' Factor} = \frac{\text{Incremental Tertiary Reserves over Project Life}}{\text{Remaining Recoverable Reserves at Start of Tertiary Flood}}$$

or 0.90 whichever is less.

Tertiary (t) factor for an existing EOR project is:

$$\text{'t' Factor} = \frac{\text{Incremental Tertiary Reserves over Project Life}}{\text{Remaining Recoverable Reserves on June 1, 1990}}$$

or 0.90 whichever is less.

Alberta will provide Section 11 royalty relief to a project if two criteria are met. First, the project must receive technical approval from the ERCB under Section 26 of the Oil and Gas Conservation Act. Second, the Minister must be satisfied that the royalty revenue accruing to the province from the project, net of relief, must at least equal the royalty revenues that would have been collected under a suitable secondary recovery scheme.

2.3 Enhanced Oil Recovery Relief (cont'd)

MANITOBA

Reduced royalty and tax rates apply to wells in qualifying new or enlarged EOR projects approved after January 1, 1987 and fully implemented before January 1, 1992. These rates are equivalent to 35% of the base Crown royalty rate for old oil, or the corresponding freehold tax incentive rate.

The incentive period is a maximum of 60 months, and is calculated based on the initial production rate and the average initial water cut for wells in the project.

EORIP = EOR incentive period = $I_o + I_{wc}$

where:

I_o = qualifying EOR incentive period in months based on the average initial oil production rate for all wells in the EOR project area.

I_{wc} = qualifying EOR incentive period in months based on the average initial water cut rate in percent for all wells in the EOR project area restricted to 24 producing months

$I_o = 72 - 9q$

q = average oil production rate in cubic metres for all wells in the EOR project area during their first four producing months.

$$I_{wc} = \frac{wc}{2.5}$$

wc = the average water cut in percent for all wells in the EOR project area during their first four producing months.

SASKATCHEWAN

EOR projects on Crown lands are subject to a pre-payout royalty of the lesser of 5% of gross revenue or 10% of operating revenue. A minimum royalty of 1% applies before investment payout. The royalty levied after project payout is the greater of 30% of operating revenue or 5% of gross revenue.

EOR projects on freehold lands are not subject to a freehold tax before payout but are levied a post-payout freehold tax of 23% on operating revenue.

Incremental oil production from a new or expanded waterflood project is entitled to a development well holiday.

EOR production is eligible for the 1% Saskatchewan Resource Credit.

2.4 Horizontal Drilling

B.C.

No horizontal drilling regime.

ALBERTA

Horizontal Well Petroleum Royalty Program

Horizontal oil wells drilled during 1991 and 1992 are eligible to receive a royalty adjustment for 24 production months. The adjustment to the royalty is made by a factor which represents the number of vertical wells replaced. This program is temporary and will be evaluated prior to its conclusion.

Crown royalty is the product of royalty calculated for adjusted production and the adjustment factor. The maximum adjustment factor is 3.

$$\text{Adjusted Production} = \frac{\text{Production}}{\text{Adjustment Factor}}$$

$$\text{Adjustment Factor} = 1 + \frac{\text{Horizontal Displacement(m)}}{\text{Spacing Unit Dimension}}$$

Spacing Unit Dimension = 800 meters for wells in pools with oil lighter than 950kg/m^3

200 meters for wells in pools with oil heavier than 950kg/m^3

2.4 Horizontal Drilling (cont'd)

MANITOBA

Horizontal Drilling Incentive Program

The incentive program provides a special crown royalty or freehold production tax holiday volume for horizontal wells or horizontal drains drilled prior to January 1, 1992. For new horizontal wells, the first 7500 cubic meters of production is free of crown royalties or freehold production taxes. For horizontal drains made from an existing well bore the holiday volume is 1500 cubic meters per drain up to a maximum of four drains per well.

In addition, production from all horizontal wells or drains drilled under the program is classified as new oil for Crown royalty or production tax purposes.

Horizontal wells are exempt from any production restrictions during the initial six months of production provided cumulative production does not exceed 7500 cubic meters of oil. Subsequent to this, the horizontal well is subject to a maximum permissible production rate of 500 cubic meters of oil per month.

SASKATCHEWAN

For non-deep horizontal wells (heavy and non-heavy) finished drilling after March 31, 1991 the first 12000 cubic meters of oil production is subject to a royalty of 5% (less the 1% Saskatchewan Resource Credit). No freehold production tax applies for the first 12000 cubic meters of oil production. All production in excess of 12000 cubic meters is subject to the new oil structure.

Deep horizontal wells receive the same fiscal treatment as deep vertical oil wells.

2.5 Royalty Tax Credits and Workover Incentives

B.C.

Royalty Tax Credit

No royalty tax credit.

Workover Incentives

No workover incentives.

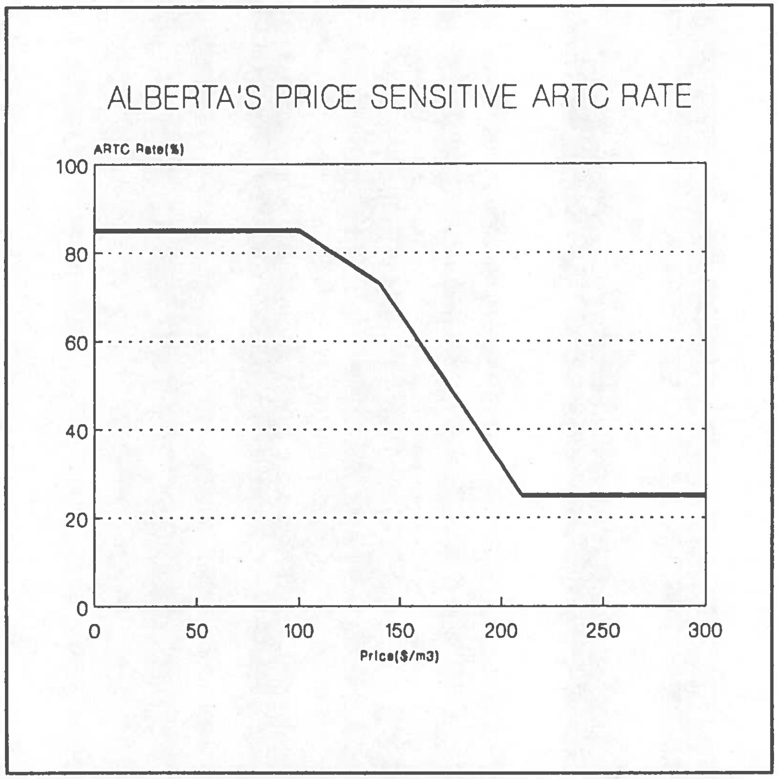

Figure 6 Alberta Royalty Tax Credit Rates at Various Prices.

ALBERTA

Royalty Tax Credit

The Alberta Royalty Tax Credit (ARTC) program provides oil and gas producers with a refundable tax credit equal to a percentage of the first $2.5 million in Crown royalty paid by each corporation. This program improves development netbacks for the smaller independent companies.

Effective January 1, 1990 to December 31, 1994 ARTC provides a variable percentage credit of a producer's first $2.5 million of royalties. The percentage credit is linked to the price of oil,* ranging from 25% for prices at or above $210/m^3 to 85% for prices at or below $100/m^3. The sliding scale formula is intended to decrease effective royalty from producers when prices are low.

ARTC % = 85 when APP $\leq$ $100/m^3 ($16/b)
ARTC % = 85 -(12/40)x(APP-100)
when $100 < APP $\leq$ $140/m^3 ($22/b)
ARTC % = 73 - (48/70)x(APP-140)
when $140 < APP $\leq$ $210
ARTC % = 25 when APP > $210/m^3 ($33/b)
where:
APP = Average Par Price of oil for the previous quarter
ARTC rates for 1990 and 1991 are as follows:

ARTC Rates

1990-1	76.17%	1991-1	25.00%
1990-2	63.40%	1991-2	60.43%
1990-3	74.70%	1991-3	73.70%
1990-4	68.66%	1991-4	72.77%

*The credit rate for both oil and gas production is linked to the oil price for administrative simplicity and because the province is more interested in encouraging oil development. When the price of oil diverged sharply from the gas price during the Gulf War, Alberta introduced a temporary gas ARTC supplement for 1991 making the minimum ARTC rate for gas production equal to 70% for producers with less than $2.5 million in oil royalty.

2.5 Royalty Tax Credits and Workover Incentives (cont'd)

MANITOBA

Royalty Tax Credit

No royalty tax credits.

Workover Incentives

No workover incentives.

SASKATCHEWAN

Royalty Tax Credit

Crown royalty and freehold production tax rates are eligible for the Saskatchewan Resource Credit reduction of one percentage point, effective June, 1988.

Workover Incentives

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

3. FREEHOLD TAXES
3.1 Crude Oil Freehold Tax

B.C.

Freehold production tax is calculated by levying a rate of \$12.50 per thousand dollars on the assessed value of each land tract.

The assessed value is determined on the basis of revenue from petroleum production from the land in the previous year.

Assessed Value = Production Revenue x Valuation Factor

F = {[(PR-T)/(N*(PM-TM))]^2* N*(PM-TM)/20.80}/PR
when average monthly well/tract production $<159m^3$

F = {[(15.84 * (PR-T)/(N*(PM-TM))] - 1259.30}*N*(PM-TM)/PR
when average monthly well/tract production $\geq 159m^3$

where:

F = Valuation factor

PR = Production revenue

N = Number of producing months during the year

T = Transportation costs

PM = Average gross price per m^3

TM = Average transportation cost per m^3

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.

COF = R*M*V*T

where:

Q = Production (m^3/year)

R = Prescribed tax rate = 0.269

M = $(0.0833*Q)^2/105.94$
when Q < 2 288.4 m^3/year (14 400 b/year)

M = (Q/4)-228.84
when Q $\geq$ 2 288.4 m^3/year (14 400 b/year)

V = Price (\$/m^3)

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

SGF = R*M*V*T

where:

R = Prescribed tax rate = 0.069

M = Annual solution gas production (10^3m^3/year)

V = Price (\$/10^3m^3)

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

3.1 Crude Oil Freehold Tax (cont'd)

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

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

New Oil

$$
\begin{aligned}
T &= 0, \text{ when } P \leq 36 \\
&= [(0.23P)-8.11], \text{ when } 36 < P < 65 \\
&= [19.59-(820/P)], \text{ when } P \geq 65
\end{aligned}
$$

Incentive Oil

$$
\begin{aligned}
T &= 0, \text{ when } P \leq 56 \\
&= [9.27-(510/P)], \text{ when } P > 56
\end{aligned}
$$

Holiday Oil

T = 0, for all volumes

SASKATCHEWAN

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

PTF = 6.9 for old oil
= 10.0 for new oil

The intent is to equalize netbacks from Crown and freehold production.

New freehold wells are entitled to a tax holiday, the duration of which is determined in the same manner as for crude oil royalty holidays.

3.2 Natural Gas Freehold Tax

B.C.

Freehold production tax is calculated by levying a rate of \$12.50 per thousand dollars of the assessed value of each land tract.

The assessed value is determined on the basis of revenue from petroleum production from that land in the previous year.

Assessed Value = Production Revenue * Valuation Factor

Valuation factor = PTR * 80.00

For Non-Conservation Gas:

$PTR = [\{0.105 * GPR_{mg}) = (0.14 * GPR_{bp})]/(GPR_{mg} + GPR_{bp})$
when $P \leq \$50/10^3m^3$

$PTR = \{[525 + 17.5 * (P-50)] * GPR_{mg}/(P * 100) + (0.14 * GPR_{bp})\}/(GPR_{mg} + GPR_{bp})$
when $P > \$50/10^3m^3$

For Conservation Gas:

$PTR = [(0.056\text{-}GPR_{mg}) + (0.14 * GPR_{bp})]/(GPR_{mg} + GPR_{bp})$
when $P \leq \$50/10^3m^3$

$PTR = \{[280 + 10.5 * (P-50)] * GPR_{mg}/(P * 100) + (0.14 * GPR_{bp})\}/(GPR_{mg} + GPR_{bp})$

where:

P = Gross production revenue of marketable gas less allowances for transportation, gas processing and royalty paid to the freehold land owner divided by sales volume

GPR_{mg} = Gross production revenue of marketable gas
GPR_{bp} = Gross production revenue of by-products
PTR = Production Tax Rate

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.

FGF = Field gas factor
ADP = Average daily production
FGF = R*M*V*T
when ADP $\geq$ 16.9 10^3m^3/day (600 mcf/day)
FGF = M*V*A*T
= when ADP < 16.9 10^3m^3/day (600 mcf/day)

where:

R = Prescribed tax rate = 0.069
V = Value ($\$/10^3m^3$)
M = Annual raw gas production (10^3m^3/year)
T = % of field gas recovered attributable to the mineral right owner
A = $R\text{-}\{[(R-0.01) * (16.9\text{-}ADP)^2]/(16.9)^2\}$

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 < 2 288.4m^3/year (14 400 b/year)
M = (Q/4)-228.84
when Q $\geq$ 2 288.4 m^3/year (14 400 b/year)
V = Price ($\$/m^3$)
T = % of total production attributable to the mineral right owner

3.2 Natural Gas Freehold Tax (cont'd)

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 produced.

SASKATCHEWAN

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

PTF = 6.9 for old gas
      = 10.0 for new gas

The intent is to equalize netbacks from Crown and freehold production.

4. CORPORATE TAXES
4.1 Federal Taxes

Effective July 1, 1988, 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 3% of tax owed is applicable to corporations for an indefinite period. Corporations are generally allowed deductions for amounts paid out to earn income, including the following: operating and lifting costs, capital cost allowance, interest expense, exploration and development expense, resource allowance, general and administrative expense and in some cases earned depletion. No deduction can be claimed for provincial royalties and freehold taxes paid.

Large corporations are assessed an additional tax of 0.2% on taxable capital employed in Canada less a capital deduction of $10,000,000. The large corporations tax may be credited against the federal surtax. In essence, the company pays the amount which is higher.

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.

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 Income (Gas Plants)
A 5% credit is available on net income earned through manufacturing and processing. Oil and gas well operation and extraction are excluded from this category. Operation of a gas plant is not, so income from gas plant operations would be eligible. In practice, this is 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, and it must be at least 10% of the company's gross revenue.

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[1] CEE: includes geological, geophysical, geochemical, drilling & 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, any rental or royalty.

4.1 Federal Taxes (cont'd)

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).

EXAMPLE OF TAX CALCULATION FORMAT

	Gross Revenue
-	Operating & Lifting Costs
-	CCA
-	Interest Expense
-	Exploration & Development Expense
-	General & Administrative Expense
-	Resource Allowance
=	Net Income
	* Tax Rate
=	Tax Payable

Resource Allowance = 25% * Net Resource Profits

	Gross Revenue
-	Operating & Lifting Costs
-	Royalties
-	General & Administrative Expense
-	Crown Lease Rentals
-	CCA
=	Net Resource Profits

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 or before 1990 - 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	25%	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.

4.2 Provincial Taxes

B.C.

Basic Corporate Tax

Effective January 1, 1991 the rate is 15% of: taxable income earned in British Columbia less the royalty tax rebate. 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.

Small Business Deduction

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

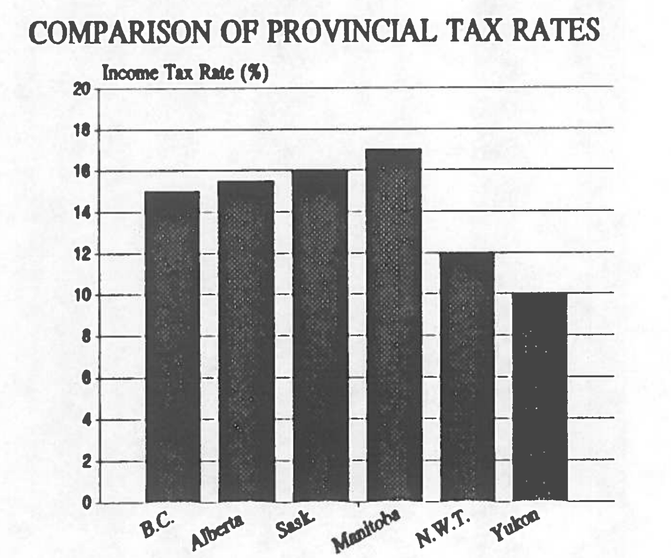

Figure 7 Comparison of British Columbia, Alberta, Saskatchewan, Manitoba, N.W.T. and Yukon Income Tax Rates.

ALBERTA

Basic Corporate Tax

Effective April 1, 1991 the rate is 15.5% of the amount taxable in Alberta. The amount taxable in Alberta is the product of taxable income as assessed for federal taxes less the royalty tax deduction and the quotient obtained when taxable income earned in Alberta is divided by taxable income.

The royalty tax deduction is the disallowed Crown royalty and freehold mineral tax less the 25% resource allowance. The deduction can only reduce the tax. Unused deductions can be carried forward.

Alberta Taxable Income = (Canadian Taxable Income - RTD) *(Alberta Allocation Factor)

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

Royalty Tax Deduction = Crown Royalties and Freehold Mineral Tax paid but not allowed as a deduction for federal income taxes - (resource allowance)

Small Business Deduction

The corporate tax rate is reduced by 9% for firms that qualify as small businesses.

MANITOBA

Basic Corporate Tax

The basic corporate tax rate is 17% of taxable income earned in Manitoba less the mineral tax rebate. The mineral tax rebate is the freehold taxes less the 25% resource allowance. No royalty tax rebate is available.

Corporate Tax Holiday

Businesses incorporated after August 8, 1988 and before January 1, 1993 will be eligible for a corporate income tax holiday in their first year of operation, and phased increases toward full tax rates over the next four years.

Small Business Deduction

The corporate tax rate is reduced by 7% for firms that qualify as small businesses.

SASKATCHEWAN

Basic Corporate Tax

Effective January 1, 1989 the rate is 15% of: taxable income earned in Saskatchewan less the royalty tax rebate. Effective January 1, 1992 the rate will increase to 16%.

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

Corporate Capital Tax Surcharge

Effective July 1, 1988 large resource corporations will be assessed a corporation capital tax surcharge, which is equal to the difference between the existing corporation capital tax liability and 2% of a corporation's value of Saskatchewan resource sales. Effective in 1990, Saskatchewan's fiscal regime incorporates a deduction of up to $50,000 per year from the Corporate Capital Tax Surcharge for resource corporations whose assets total less than $100 million.

Corporate Tax Holiday

Businesses incorporated before April 1, 1992 are eligible for a two-year corporate income tax holiday.

Small Business Deduction

The corporate tax rate is reduced by 5% for firms that qualify as small businesses.

5. APPENDICES
Appendix 5.1

Comparison of the Oil and Natural Gas Resources of the Western Canadian Provinces and Territories

The ultimate oil potential of the Western Provinces and Territories is estimated to be 4.3 billion cubic metres, 68% of which is located in Alberta. Of Alberta's oil resources, 60% has been produced, 18% is in remaining established reserves and 22% remains undiscovered.

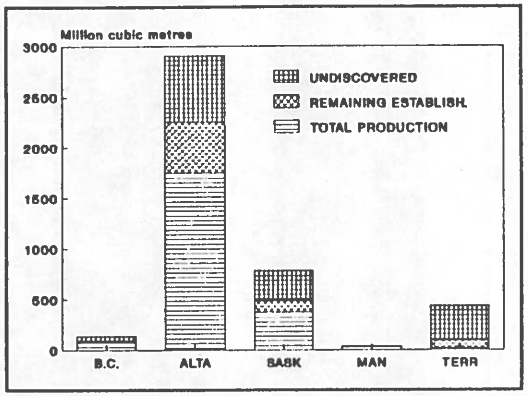

Figure 8 Ultimate Potential of Crude Oil (at 1989-12-31).

The ultimate natural gas potential of the Western Provinces and Territories is estimated to be 8 trillion cubic metres, 60% of which is located in Alberta. Of Alberta's natural gas resources, 35% has been produced, 35% is in remaining established reserves and 30% remains undiscovered.

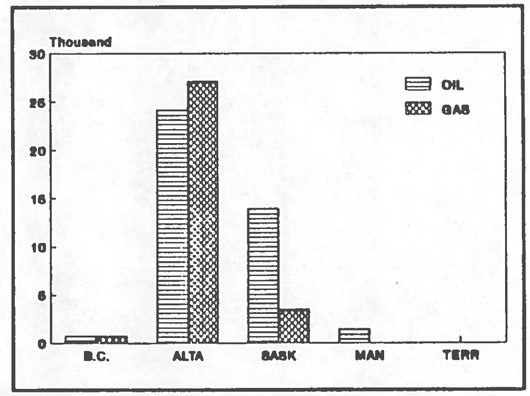

Figure 10 Producing Wells (1989).

The areas with significant reserves yet to be discovered are Alberta (649 million cubic metres), the Territories (344 million cubic metres) and Saskatchewan (297 million cubic metres). Alberta has a reserve life of 21 years of oil, based upon remaining established plus undiscovered reserves. B.C. and Saskatchewan have around 35 years of oil production each, while the relatively undeveloped Territories has a reserve life greater than 200 years.

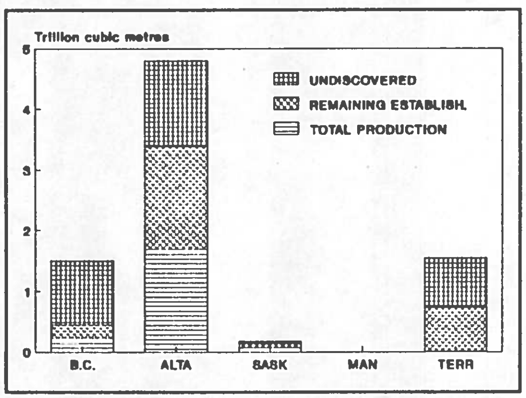

Figure 9 Ultimate Potential of Natural Gas (at 1989-12-31).

The areas with significant reserves yet to be discovered are Alberta (1.4 trillion cubic metres), B.C. (1.0 trillion cubic metres) and the Territories (0.8 trillion cubic metres). Alberta has a reserve life of 37 years of gas, B.C. has 92 years, Saskatchewan has 19 years, while the Territories has a reserve life greater than 1000 years.

Figures 8 and 9 present the ultimate potential of oil and natural gas for the Western Provinces and Territories.

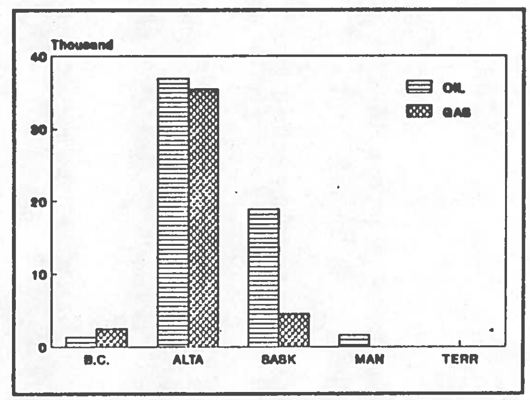

Figure 11 Wells Capable of Production (1989).

Appendix 5.1 (continued)

Figures 10 and 11 present the number of producing wells and wells capable of production. Alberta, with the largest resource base, has 35% of its oil wells and 24% of its gas wells shut-in. The number of shut-in wells is the difference between wells capable of production and those being produced. B.C. has 45% and 71% shut-in oil and gas wells, respectively, while Saskatchewan has 27% and 24% shut-in oil and gas wells. Manitoba has 14% of its oil wells shut-in.

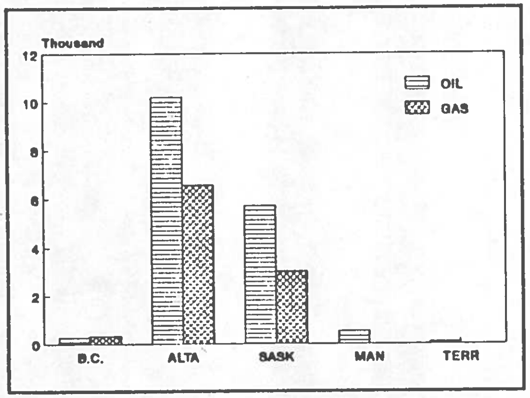

Figure 12 Successful Wells Drilled (from 1985 to 1989).

Alberta has the highest drilling density with a ratio of one well for every 160 square kilometres. B.C.'s ratio is one well to 3,300 square kilometres. Saskatchewan's is one well to 500 square kilometres and Manitoba's is one well to 7,800 square kilometres. The Territories has the lowest drilling density with one well for every 276,000 square kilometres.

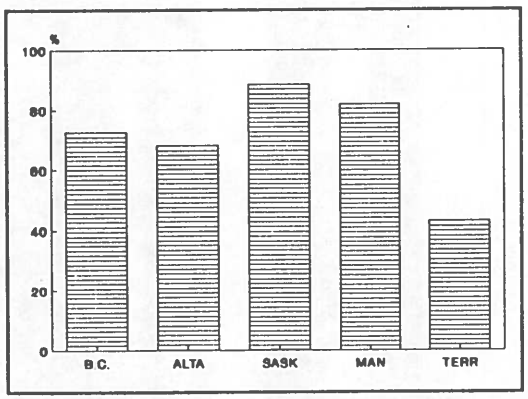

Figure 13 Overall Success Rate (for combined oil and gas, exploratory and development wells, 1989)

Figures 12 and 13 present the number of successful wells drilled for the period 1985 to 1989, and the overall drilling success rate (taking into account oil and gas, exploratory and development wells).

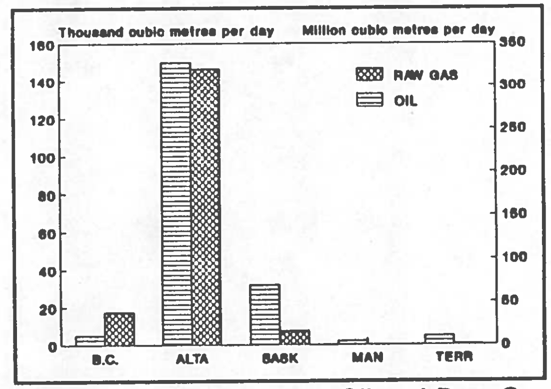

Figure 14 Production of Oil and Raw Gas in 1989.

Figure 14 presents total production of oil and raw gas in 1989. On a per well basis, Alberta production was 6.2 cubic meters per day for oil, and 11.8 thousand cubic metres per day for raw gas. B.C.'s production on the same basis was 7.3 cubic metres and 53 thousand cubic metres per day for oil and raw gas respectively. Saskatchewan's production per well was 2.3 cubic metres and 4.9 thousand cubic metres per day for oil and raw gas respectively. Manitoba's oil production was 1.5 cubic metres per day per well.

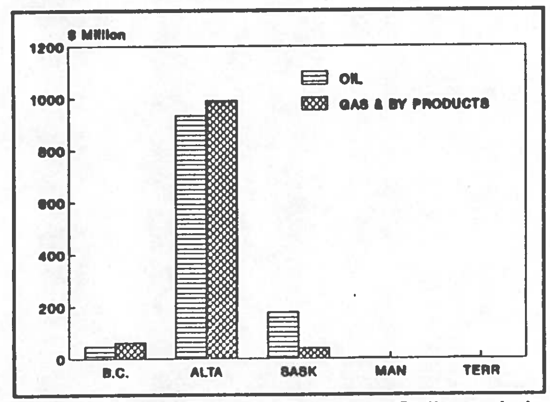

Figure 15 Crown Royalty Collected in 1989.

Figure 15 presents royalties collected by the provinces.

Appendix 5.2

Comparison of Oil and Gas Fiscal Regimes for Alberta, British Columbia and Saskatchewan

This section presents a comparative economic evaluation of oil and natural gas exploration and production across existing fiscal regimes in Alberta, British Columbia and Saskatchewan. The analyses are intended to provide a picture of how the oil and gas fiscal regimes of British Columbia and Saskatchewan compare to that of Alberta. They are not intended to be representative of any specific area or geological type of play. Oil and natural gas plays were assessed along borders between provinces. The analyses were done on a full-cycle, per successful exploratory well basis, and are risk weighted. The exception to this is the Alberta - Saskatchewan conventional heavy crude oil comparison which was done on a half-cycle, per producing well basis. In order to compare and evaluate the impact of the three provinces fiscal regimes, it was necessary to create a level playing field. This was done by assuming, since the plays were located along the border area, that the play geology and the play specific capital and operating costs would be the same for the provinces being compared. The selling price of the oil and natural gas was assumed to be the same in each comparison.

<u>Summary of Fiscal Assumptions</u>

All Provinces
- Stand alone tax basis.
- Canadian Oil and Gas Property Expense (COGPE) - 10% declining balance.
- Canadian Exploration Expense (CEE) - 100% expensed in years 1 and 2.
- Canadian Development Expense (CDE) - 30% declining balance.
- Capital Cost Allowance (CCA) - 25% declining balance.
- 4.5% operating and capital cost inflation.
- 25% resource allowance.
- 28% federal income tax.
- 3% federal surtax.

Alberta
- New gas and new oil royalties.
- Royalty tax credit (ARTC)
- Income tax rate of 15.5%

British Columbia
- Non-associated gas and new oil royalties.
- Income tax rate of 15%

Saskatchewan
- New gas and new oil royalties.
- Resource credit of one percentage point.
- Income tax rate of 15%

<u>Project Time Schedules</u>

Natural Gas
- Exploration drilling starts at beginning of 1991.
- Successful well completed by the end of 1991.
- Development in 1992.
- Production begins at start of 1993.

Conventional Crude Oil
- Exploration drilling starts at beginning of 1991.
- Successful well completed in 1991.
- Development in 1991.
- Production begins at start of 1992.

Conventional Heavy Crude Oil
- Development in 1991.
- Production begins at start of 1992.

Appendix 5.2 (continued)

Comparison of Fiscal Regimes
Alberta versus British Columbia

The returns to industry of exploring for and producing natural gas and conventional crude oil indicate that the Alberta and B.C. fiscal regimes are approximately equivalent in terms of generosity. However, a company which benefits significantly from ARTC would find the Alberta regime to be more favourable for conventional crude oil.

Summary of Play Assumptions

Natural Gas
This is a 900 metre deep gas play with 510 million cubic metres of recoverable marketable gas. Gas condensate is assumed to be absent. The initial gas production rate is 70 thousand cubic metres per day per well declining exponentially. The exploration success rate is 35%, while the development success rate is 70%. There are 4 production wells in the play (1 exploratory and 3 development wells) with one section spacing. The natural gas price used in the analysis was $48.5 per thousand cubic metres in 1991 increasing at 4.5% per year.

Conventional Crude Oil
This is a 1575 metre deep oil play with 70 thousand cubic metres of recoverable oil in place. The initial oil production rate is 8.0 cubic metres per day per well declining exponentially. The exploration success rate is 29%, while the development success rate is 87%. There are 3.2 production wells in the play (1 exploratory and 2.2 development wells) with quarter section spacing. The oil price used in the analysis was $140 per cubic metre in 1991 increasing at 4.5% per year.

Note that the crude oil analysis includes a two year exploratory well and a one year development well holiday for Alberta, and a three year exploratory well holiday for British Columbia.

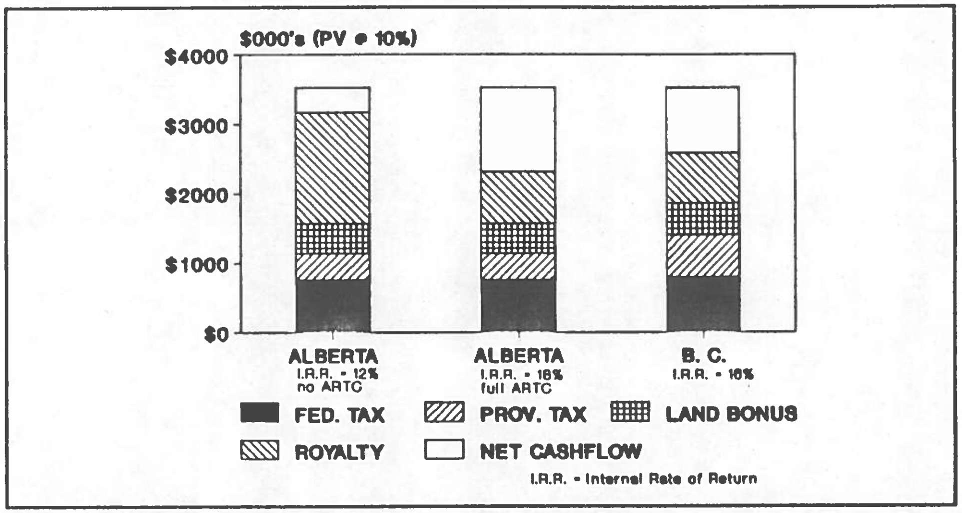

Figure 16 Alberta vs. British Columbia Comparison of Fiscal Regimes for a Natural Gas Play (using a 10% expected real rate of return).

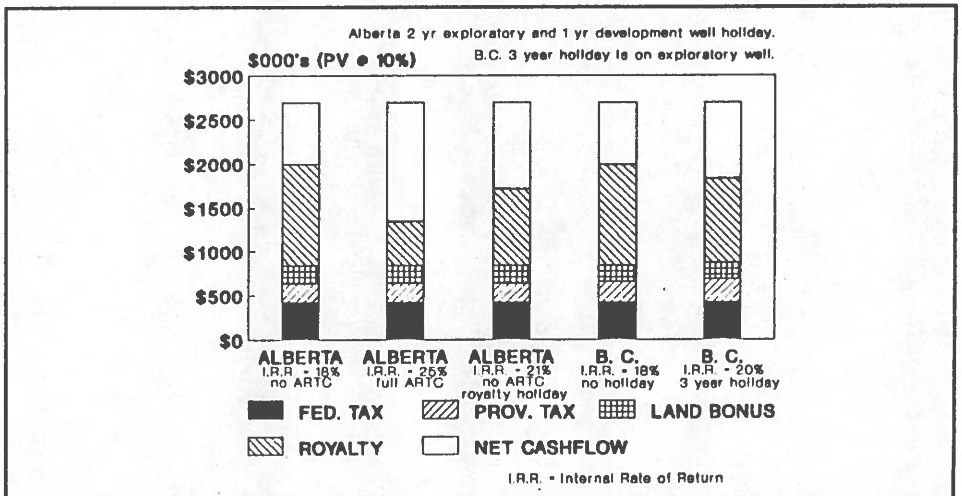

Figure 17 Alberta vs. British Columbia Comparison of Fiscal Regimes for a Conventional Oil Play (using a 10% expected real rate of return).

Comparison of Fiscal Regimes
Alberta versus Saskatchewan

The returns to industry of exploring for and producing natural gas in Alberta and Saskatchewan indicate that the two fiscal regimes are approximately equivalent in terms of generosity. Given a 15% price advantage for Saskatchewan natural gas, returns to industry for that province improve significantly. For conventional heavy crude oil, Alberta's fiscal regime appears to be more generous.

<u>Summary of Play Assumptions</u>

Natural Gas

This is a 450 metre deep gas play with 100 million cubic metres of recoverable marketable gas. Gas condensate is assumed to be absent. The initial gas production rate is 25 thousand cubic metres per day per well declining exponentially. The exploration success rate is 36%, while the development success rate is 64%. There is 1 production well (exploratory well) in the play with one section spacing. The natural gas price used in the analysis was $48.5 per thousand cubic metres in 1991 increasing at 4.5% per year.

Conventional Heavy Crude Oil

This is a 610 metre deep oil play with 10 thousand cubic metres of recoverable oil in place. The initial oil production rate is 5.6 cubic metres per day per well declining exponentially. Only primary production was assessed in the analysis. The development success rate is 100%. There is 1 production well (development well) in the play with one-sixteenth section spacing. The oil price used in the analysis was $74 per cubic metre in 1991 (for 16 degree API oil) increasing at 4.5% per year.

Note that the heavy oil analysis includes a one year development well holiday for Alberta, and a two year development well holiday for Saskatchewan.

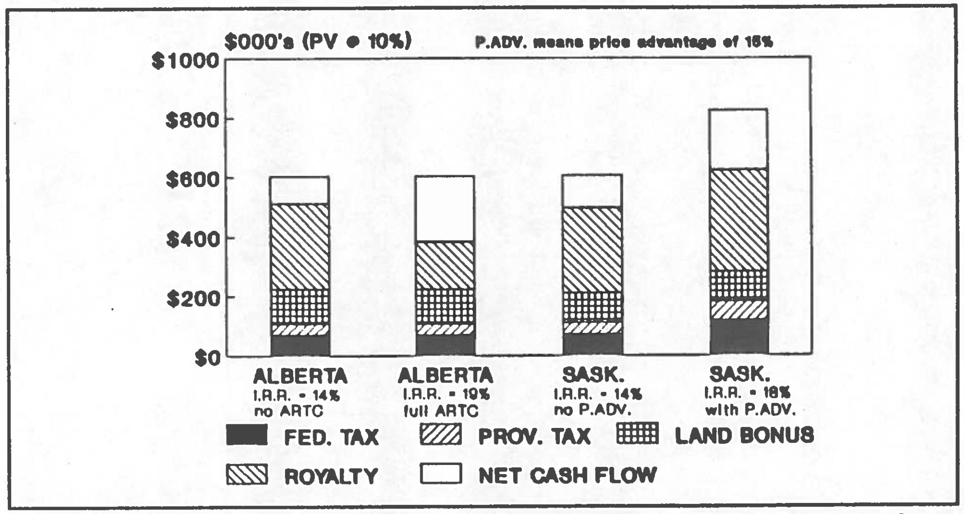

Figure 18 Alberta vs. Saskatchewan Comparison of Fiscal Regimes for a Natural Gas Play (using a 10% expected real rate of return).

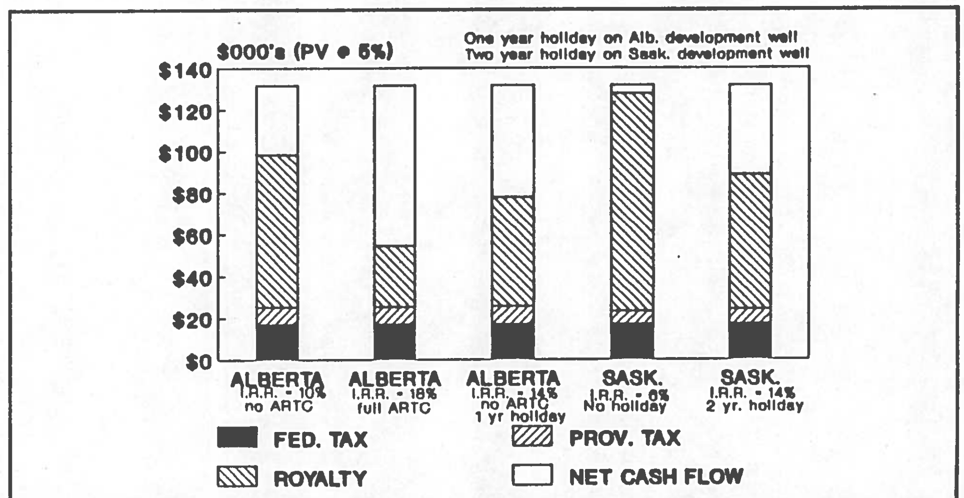

Figure 19 Alberta vs. Saskatchewan Comparison of Fiscal Regimes for a Conventional Heavy Oil Play (using a 5% expected real rate of return).

I.R.R. = Internal Rate of Return