DOE/RA/33211--T1

CANADIAN INCENTIVES FOR

OIL AND GAS EXPLORATION

Contract No. DE-AC01-80RA33211

Prepared for the U.S. Department of Energy
Office of Resource Applications
Washington, D.C. 20461

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April, 1980

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I INTRODUCTION

One of the objectives of the energy policy of the United States is a reduction in oil imports by half by the end of the 1980's. To accomplish this reduction a number of initiatives have been proposed, including the increased development of domestic petroleum and natural gas resources. In developing policies and programs to encourage increased domestic energy production, the Department of Energy, Office of Resource Applications (DOE/RA) is reviewing and evaluating various incentives that might encourage exploratory drilling for oil and natural gas.

During the 1970's a number of different exploration and production incentive programs were put in place in Canada, in particular in the Province of Alberta, Canada's principal oil and gas producing province. The DOE/RA is evaluating Canadian incentives for oil and gas exploration and this study is intended to provide information that will help guide DOE/RA in determining the applicability of Canadian incentive programs in U.S. energy policy.

Scope of the Study

The study describes and documents the fiscal structure in which the Canadian oil industry operates. The incentive features of pricing policy, taxation policy and provincial royalty systems are discussed. A principal focus of the study is on one of the most important of Canada's specific incentive programs, the Alberta Exploratory Drilling

Incentive Credit Program (EDICP). The study describes and evaluates the effect of the EDICP on increased oil and gas exploration activity. Similarly, the study also reviews and evaluates other specific incentive programs such as the Alberta Geophysical Incentive Program, Frontier Exploration Allowances, and various tar sand and heavy oil development incentives. Finally the study evaluates the applicability of Canadian incentives to U.S. energy policy.

Conduct of the Research

This research project was conducted by D. Barry McKennitt, President, Energy Associates, Concord, Massachusetts.

Acknowledgements

Energy Associates gratefully acknowledges the cooperation received from various governmental agencies, private companies and individuals during the study. Personnel at the Alberta Department of Energy and Natural Resources, the Alberta Energy Resources Conservation Board, the Canadian Petroleum Association, the British Columbia Energy Commission, the British Columbia Petroleum Corporation, Finance Canada, and Energy Mines and Resources Canada were particularly helpful. Also, valuable inputs were made by a number of oil and gas companies in Canada who contributed freely of their information and experience.

II SUMMARY AND CONCLUSIONS

Summary

Development of Incentives

Government policies have had a major impact on Canada's petroleum industry during the 1970's. This impact derived from changes in oil and gas pricing, royalties and tax treatment. The regulated price of oil and gas is established by negotiation between the federal government and the producing provinces. As the ownership of natural resources is vested in the provinces in Canada, royalty rates are set by provincial authority. At both the federal and provincial levels government incentives are in place to encourage investment by Canada's petroleum industry. Federal incentives operate essentially through taxation policy. Provincial incentives in the industry cover a wider spectrum and include credit, rebate and grant programs, as well as taxation and royalty rate factors. A dominant trend in incentives has been towards earned incentive programs where specific expenditures must be made in order to earn tax deductions or credits. Canada's oil and gas incentive programs did not develop as part of a unified strategy but evolved on a step by step basis in response to particular needs.

Prices, Royalties and Taxation

Canadian oil and gas prices moved up rapidly during the 1970's but lagged far behind world price levels at the close of the decade. Alberta

oil prices rose from \$2.82 per barrel in 1972 to \$14.75 per barrel in 1980, an average increase of 23% per year for the period. Natural gas prices moved up even faster from 15¢ per mcf in 1972 to \$1.88 per mcf in early 1980, an average increase of 36% per year for the period.

With the increase in the price of oil from \$3.80 per barrel to \$6.50 per barrel in April of 1974, Alberta sharply increased its royalty take effectively short circuiting the federal government's participation in the higher revenues. The federal government acted to protect its position by making provincial royalties non-deductible for federal tax purposes leaving the oil industry in a situation of double taxation. Industry activity dropped sharply until adjustments were made in royalty provisions and the federal government introduced a resource allowance which permitted the deduction of 25% of resource profits from income effective January 1976. With the resolution of this federal provincial revenue sharing conflict industry activity resumed.

Except for the period of double taxation above, the net back to the producer from oil and gas production has improved with the increase in prices. For companies in a taxable position that could utilize the benefits of the deductability of exploration expenses and earned depletion the improvement in net back has provided an on-going incentive.

The principal features of the tax treatment of oil and gas expenditures in Canada include, the 100% deductability of all exploration expenses, a 30% writeoff of development expenditures, a resource allowance deduction of 25% of resource income, and an earned depletion deduction of 33-1/3% of

exploration and development expenditures. The combined effect of the level of provincial royalties and the tax treatment of resource expenditures far out weighs the impact on industry profitability of any of the specific incentive programs instituted by the producing provinces..

Alberta's Exploratory Drilling Incentive Programs

The province of Alberta introduced the Exploratory Drilling Incentive Credit Program (EDICP) in August of 1972 to stimulate the discovery of crude oil reserves and to shift exploratory activity back to the province. The program also was meant to provide an offset to the industry against a \$70 million increase in provincial royalties effective January 1973. Beginning in the latter part of the 1960's exploratory activity was moving away from the provinces to the federally controlled frontier areas. The industry was attracted away from what was considered mature exploration areas such as Alberta, to the search for 'big oil' in the frontiers, especially the Canadian north. Alberta was concerned that the largest producers in the province were withdrawing revenues from Alberta to finance exploration elsewhere. Consequently a key feature of the EDICP required that companies spend money in Alberta in order to reduce their payments to the Alberta government by the amount of credit earned.

The EDICP program developed in four stages.

Stage One. August 1, 1972 to December 31, 1973. Only New Field Wildcats were eligible and approximately 30% of the cost of the well could be earned as a credit. The total footage of the well was

eligible. A five year royalty holiday was granted to oil discoveries.

Stage Two. January 1, 1974 to December 31, 1974. Mechanical rules were introduced to define qualifying wells and New Pool Wildcats and Deeper Pool tests were included. The province was divided into three regions to recognize differences in costs and up to 40% of deep footage cost could be earned as credit. A two year royalty holiday was granted for natural gas discoveries. The credit was expanded to cover bonus bids as well as royalties, rentals or mineral taxes.

Stage Three. January 1, 1975 to December 31, 1977. Incentives were increased by increasing the recognized well costs and the credit support was increased to 50% for Class A footage and 37-1/2% for Class B footage. Geophysical incentives were introduced.

Stage Four. January 1, 1978 to present. The drilling credit areas were redefined. The upper 2000 feet of all wells were excluded from incentives but incentives were increased below 3500 feet and the incentive increased to as high as 75% of cost at depths below 5000 feet. The royalty holiday for gas was reduced to one year.

Alberta Geophysical Incentive Program

A geophysical incentive program was implemented on January 1, 1975 to stimulate the level of seismic exploratory activity in Alberta. From the late 1960's through the early 1970's there was a sharp drop in geophysical activity in western Canada and a pronounced shift of activity away from the

province of Alberta. The geophysical industry was severely depressed at a time when Alberta was seeking to augment its exploratory drilling incentives. Seismic credits were introduced to correct this situation.

The program provided for a credit based on the number of miles of subsurface coverage and the area of the province in which the survey was conducted. Credits could be offset against royalties or other natural resource payments due the province, or claimed as a cash rebate by operators, such as seismic contractors, who did not own mineral rights. The program originally was to expire on March 31, 1978 but was extended to March 31, 1980, although the credit was halved. The regulations provide that geophysical information obtained under an incentive credit program must be made available for sale at the end of three years.

Impact of Alberta Incentive Program

The precise impact of the Alberta incentive programs on exploratory activity is a complex assessment because other fundamentally critical factors such as pricing, royalty and taxation were undergoing significant changes throughout the existence of the incentive programs. For the Alberta government the incentive programs have been successful in meeting their objectives of having producers reinvest their revenues in Alberta to promote the discovery of oil and gas. Oil industry investment in Alberta has surged especially through the 1976 - 1979 period, and significant new discoveries of oil, and especially of natural gas, have been made. The direct financial return to the province from increased royalties and lease bonuses has greatly exceeded the cost of all the incentive program credits.

Although exploratory drilling credits were established in 1972 and increased in 1974 and 1975, total exploratory drilling activity showed only modest growth until 1976. In this period total drilling activity in Alberta improved but largely at the expense of declines in Saskatchewan and British Columbia which was more a reflection of the relatively more negative conditions in the latter provinces than of the positive conditions of Alberta. The lack of a better performance is directly attributable to the double taxation which resulted from the federal-provincial revenue sharing conflicts of 1974.

Following provincial royalty revisions and the introduction of the federal Resource Allowance on January 1, 1976, exploratory and drilling activities picked up dramatically. This reflected the restoration of producer net back, which led to a restitution of producer confidence.

Industry made every effort to qualify wells for incentive credit and about half of all the exploratory wells drilled in recent years have qualified for credit. In some instances qualifying for credit may have meant compromising the geological location of a well to meet the incentive definition. A large number of New Pool Wildcat wells that qualified for incentive credit were drilled into widespread, and well known, shallow gas sands. Many of these wells may have been closer to development type wells and in any case, this activity was not a purpose of the incentive program. The first 2000 feet of all wells were subsequently excluded from earning incentives.

The apparent lack of a significant increase in deep drilling activity can be attributed to several factors. There are a limited number of operators who are able to conduct this high cost, high risk activity even including the incentives. This was particularly true in the light of the highly favorable discovery experience in the conventional areas of Alberta which could be drilled for lower cost and at lower risk. Additionally, deep drilling has been limited by rig availability and all deep rigs have operated at capacity. Finally, the deep prospects have been gas prone and there has been an absence of new markets for natural gas in Alberta.

Although the incentive programs may have been responsible for maintaining exploration activity in the 1972 through 1975 period, and even responsible for getting exploration activity moving again in the middle 1970's, it was also the outstanding success ratios enjoyed in Alberta that sustained the growing momentum of exploration activity in the latter 1970's. The exploratory success ratio in Alberta has exceeded 50% in each year from 1976 through 1979, and the development well success ratio for this period has approached 90%. A fundamentally favorable economic environment, combined with these discovery rates, tends to override the marginal effects of any specific incentive programs.

The geophysical incentives were broadly utilized in the first years after their introduction because the cost reimbursement was relatively generous. The biggest users of the program were independent seismic contractors. Although a number of major companies preferred not to utilize the program because of its requirement that information be publicly released

after three years, Chevron did make extensive use of the program. Chevron, a seismically oriented company, made maximum use of the program, and the seismic obtained led directly to the discovery of the West Pembina fields. There were, however, numerous abuses of the program, by those who minimized costs and quality in an effort to maximize the incentive return.

The total costs of the incentive program to Alberta has risen from \$12.7 million in their first full year to over \$114 million in 1978. The incentive programs are administered by a relatively small staff, which in total numbers less than a dozen people. The total value of the incentives earned by industry has amounted to only about 1½% of their total expenditures in Alberta in recent years. The drilling incentive credits have, however, amounted to a meaningful 15% of expenditures on exploratory drilling. Thus the program has been effective in focusing its impact. The contribution of increased oil and gas industry activities to the revenues of the province of Alberta has been impressive. Provincial revenues from the oil and gas industry have increased sevenfold over the five year period 1973 to 1978, from \$500 million to \$3.5 billion.

Other Incentives

The Frontier Exploration Allowance, called Super-depletion, was introduced in March of 1977, and expired as scheduled on March 31, 1980. Super-depletion was a powerful incentive which was directly responsible for launching large scale exploration programs in Canadian frontiers, particularly in the offshore in northern areas. Because of the structure and richness of the incentive,

operators may not have acted to minimize costs. Furthermore, a limited number of certain high tax bracket investors may have been able to invest at little or no cost or even at an after tax profit. Nevertheless, the program accomplished its objective of accelerating wider exploration in frontier areas. Additionally, the program has been responsible for putting in place the infrastructure necessary to carry on frontier exploration programs which appear to be on the verge of making major discoveries of national significance.

The incentives in place for oil sands and heavy oil development are essentially embodied in the Canadian tax laws which permit the immediate or rapid deductability of most expenditures dedicated to heavy oil recovery. Beyond the normal features of the tax code each tar sands plant or enhanced heavy oil recovery plant negotiates their particular fiscal terms with government on a project by project basis. The main feature of these negotiations involve a reduction in royalty rates.

Conclusions and Recommendations

1. High rates of reinvestment in the Canadian oil and gas industry have been underwritten by the favorable tax treatment of exploration and development expenditures, and by a program of price realism. Producer net backs have been further supplemented by special incentive programs designed to encourage specific objectives.
2. The Province of Alberta is uniquely situated for the establishment and administration of exploratory drilling incentive programs because it lies within a single sedimentary basin of relative uniformity. The Alberta Energy Resources Conservation Board has a complete listing of information on every well drilled in the Province permitting a timely classification and qualification of each proposed incentive well. Furthermore, the Province owns over 80% of all the mineral rights in the Province permitting a degree of flexibility and control over the supply and terms of leases not possible in the United States. Provincial government control of royalties and lease bonuses also provides the mechanism by which earned incentives can be monetized.

3. It would be complex and difficult to design an effective, yet equitable, drilling incentive program for implementation in the United States that was a replica of the Alberta type exploratory drilling incentive program. The United States has a multiplicity of geological basins each with different drilling, risk and cost conditions. There does not exist, in most States, a satisfactory compendium of well information to administer a program such as Alberta has instituted. There is no similarity between the Provincial resource land ownership and royalty system in Canada and the land ownership and royalty system in the United States.
4. At the present time an Alberta type, blanket exploratory drilling incentive program does not appear warranted in the United States. Current exploratory activity is already pressing the supply capabilities of the oil service sector. There does not appear to be a reluctance on the part of industry to conduct exploratory drilling, even in high cost areas.
5. Specific 'rifle-shot' incentives may, however, be appropriate, and required, where they can be directed towards specific areas or geologic horizons of potential that industry are not now exploiting. Such incentives might act to accelerate the timing of exploration in remote, difficult access, or especially high risk or high cost areas.
6. The United States already has in place powerful incentive programs embodied in natural gas and crude oil price decontrol programs. Specific incentives might be constructed by applying selective exemptions from the windfall profits tax to specific classes of production. Desired incentives might thus be created by modifying existing mechanisms, rather than creating new ones.

III DEVELOPMENT OF INCENTIVE PROGRAMS

Background

Government incentives in Canada's petroleum industry are in place at both the federal and provincial levels. The regulated price of oil and gas is established by negotiation between the federal government and the producing provinces. Federal incentives operate essentially through taxation policy. Provincial incentives in the oil and gas industry cover a wider spectrum and include credit, rebate and grant programs, as well as taxation and royalty rate factors. Incentive programs were established at provincial levels to encourage the development of a resource that was owned by the provinces, and, particularly in the case of Alberta, to encourage an industry that was an important factor to the economic well-being of the total province.

Under Canadian constitutional powers, ownership of natural resources is vested in the provinces. Ownership implies the right to determine the management, development, production and pricing of the natural resource. The taxing powers of the provinces are limited to direct taxation. The federal government has broad taxing authority and, through its jurisdiction over all interprovincial and international commerce, has authority over pricing of resources sold outside the producing provinces. Thus the area of oil and gas pricing overlaps both federal and provincial jurisdictions. Pricing therefore is an area of potential federal-provincial conflict based on the differing objectives of the two levels of government.

Government policies had a major impact on Canada's petroleum industry during the 1970's. Much of this impact revolved around changes in tax treatment afforded the industry. Both federal and provincial government levels offer various incentives. The federal incentive package operates through the federal income tax system. The incentive package offered by the three producing provinces operate to reduce monies payable to the provincial governments.

A summary of the main government incentives available to the Canadian petroleum industry is presented on Table 1. There are basically two broad categories of incentives: automatic and earned. The dominant trend in establishing incentives schemes has been toward earned incentive programs. The requirement to earn incentive credits through qualified expenditures promotes reinvestment and by structuring qualifying expenditures these programs can be directed towards more specific objectives. The federal resource allowance operates as an automatic reduction in the tax rate without regard to any specific expenditure requirement. The federal depletion allowance and exploration and development expensing are earned allowances where deductions from taxable income can only be generated by making certain qualified expenditures. Similarly, all the provincial incentive schemes shown on Table 1, except for the Alberta royalty tax credit and the provincial royalty rebate schemes, must be earned by the industry by making qualified expenditures.

TABLE 1

INCENTIVES IN THE CANADIAN OIL AND GAS INDUSTRY

Incentive	Objectives	Application	Credit to:
Resource Allowance	- to reduce the effective rate of federal tax (to compensate for non-deductibility of royalty in computing taxable income)	- 25% deduction from income on a defined basis	- deducted from taxable income
Earned Depletion	- to encourage the undertaking of risks inherent in resource exploration and development	1. lesser of 1/4 of resource profits or 33-1/3% earned depletion on conventional oil and gas operations & oil sands operations (including social assets and townsite facilities)	- deducted from taxable income
1. Ordinary depletion			
2. Supplementary depletion		2. 50% earned depletion on enhanced recovery and oil sands equipment, up to 50% of total income after deducting ordinary depletion	
3. Frontier depletion		3. 66-2/3% earned depletion on exploratory drilling costs in excess of \$5 million per well, up to the remaining income after deducting all other depletion allowances	
Exploration Expensing	- to allow recovery of most of the investment before taxes are paid on resource income	- 100% of defined Canadian exploration expenses	- deducted from taxable income
Development Expensing		- 30% of defined Canadian development expenses, 100% for new mines which includes oil sands operations	- deducted from taxable income

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TABLE 1

INCENTIVES IN THE CANADIAN OIL AND GAS INDUSTRY (continued)

Incentive	Objectives	Application	Credit to:	
ALBERTA	Exploratory Drilling Incentive System	<ul style="list-style-type: none">- stimulate exploratory drilling activity- accelerate discovery of petroleum reserves- stimulation of rural economies	<ul style="list-style-type: none">- certified drilling program earns credit according to schedule outlined in regulations	<ul style="list-style-type: none">- lease rentals, penalties, royalties, provincial taxes
	Geophysical Incentive Program	<ul style="list-style-type: none">- stimulate level of geophysical activity- retain nucleus of skilled geophysical personnel in Alberta	<ul style="list-style-type: none">- certified geophysical program earns credit according to formula	<ul style="list-style-type: none">- lease rentals, penalties, royalties, provincial taxes
	Royalty Tax Credit	<ul style="list-style-type: none">- increase industry cash flow by reducing royalties payable	<ul style="list-style-type: none">- lesser of (1) 25% of corporations attributed Alberta royalty income, or (2) \$1,000,000	<ul style="list-style-type: none">- credit against total tax payable
	Alberta Royalty Rebate	<ul style="list-style-type: none">- increase industry cash flow by reducing provincial tax payable (to compensate for royalty non-deductibility)	<ul style="list-style-type: none">- rebate calculated using formula. If Alberta tax payable is less than this amount take tax payable as rebate	<ul style="list-style-type: none">- credit against provincial tax payable
SASKATCHEWAN	Approved Expenditure Grants	<ul style="list-style-type: none">- increase investment in oil and gas industry	<ul style="list-style-type: none">- credit calculated as 75% of approved expenditures	<ul style="list-style-type: none">- financial assistance paid to firm out of Saskatchewan Heritage Fund
	Certified Exploratory Well Grants	<ul style="list-style-type: none">- increase exploratory drilling activity	<ul style="list-style-type: none">- credits calculated with formula	
	Saskatchewan Royalty Rebate	<ul style="list-style-type: none">- increase industry cash flow by reducing royalties payable	<ul style="list-style-type: none">- difference between provincial tax payable and provincial tax due if royalties were deductible but not resource allowance	<ul style="list-style-type: none">- credit against provincial tax payable
B.C.	B.C. Royalty & Deemed Income Rebate	<ul style="list-style-type: none">- increase industry cash flow by reducing royalties payable	<ul style="list-style-type: none">- difference between provincial tax payable and provincial tax due if royalties were deductible but not resource allowance	<ul style="list-style-type: none">- credit against provincial tax payable

Source: Government Incentives in Canada's Petroleum Industry.
W.B. Friedenberg, Z.C. Slagorsky, and A.J. Walsh. Working Paper 80-1,
Canadian Energy Research Institute, Calgary, Alberta, Canada.

Evolution of Incentives Development

The history of the Canadian oil industry prior to the 1970's was one of a relatively low level of government involvement. The 1970's by contrast brought about intense governmental involvement in all spheres of the industry's activities. This was particularly true in those areas impacting the economic factors of the industry; pricing, royalties, and taxation. The impetus for heightened government involvement was the sharply rising trend of international oil prices following the oil embargo of 1973 and 1974. However, even before that period government had begun to take actions designed to spur the exploration activities of the oil industry. As Canada began to focus on the need for additional oil development, policies began to be instituted to encourage more activity. For example, in 1971 the federal government made depletion an allowance that had to be earned by expenditure instead of an automatic allowance. Throughout the 1970's both provincial and federal governments have tried to balance the dual objectives of encouraging exploration for and development of additional supplies of oil and gas while, at the same time, assuring an appropriate level of government participation in the economic rent due to the resource.

The first provincial incentive program was Alberta's Exploratory Drilling Incentive Credit Program (EDICP) instituted in August 1972. Since then this program has undergone a number of modifications. Beginning in 1973, concurrent with the rapid escalation of world crude oil prices, tax, royalty, and incentive changes were instituted more

frequently. In fact, the pace of change in once stable parameters was so rapid during the 1973 through 1978 period that fiscal changes occurred as often as every few months. Appendix A documents the major incentive, tax, and royalty changes as they occurred throughout the 1970's.

The present study concentrates only on the most important of the major incentive packages enacted during the 1970's, specifically the Exploratory Drilling Incentive Credit Program (August 1972), the Geophysical Incentive Program (January 1975), the Frontier Exploration Allowance (March 1977), and oil sands and heavy oil incentives. It is important to note, however, that concurrent with the above programs, or as a part of them, prices, royalty rates, and taxes were constantly changing throughout the period under study.

Today Canada has in place a number of incentive schemes for the oil and gas industry (Table 1). The programs currently in effect did not develop as a part of a unified strategy. On the contrary they were instituted on a step-by-step basis, often as a result of the necessity to iron out conflict in policies established at the federal and provincial levels. The present system has been evolutionary in nature. The incentive systems have responded, and for the most part responded well and on a timely basis, to unforeseen trends in world oil prices and inflationary cost trends.

IV CANADIAN OIL AND GAS PRICING, ROYALTY, AND TAXATION

Canadian oil and gas prices moved up rapidly through the 1970's but in spite of that lagged far behind world price levels at the close of the decade. Producing company netback on oil and gas production also showed a favorable trend during the 1970's but did not keep pace with price increases as sharply escalating royalties and taxes took a major share of higher well head prices.

In response to the price movements of the 1970's provincial royalty rates and federal oil and gas taxation policy underwent dramatic changes as both federal and provincial governments sought to maximize benefits from the higher revenues. After a period in 1974 when tax and royalty levels caused industry exploration activity to decline, both provincial and federal governments modified royalty and tax policy to enhance the economic return to the industry.

There is a constant interplay between oil and gas prices, royalties and taxation. The level of royalties and taxes are price dependent. Although we discuss prices, royalties, and taxation separately below, they are indeed one interrelated subject. It is not prices, royalties or taxation per se that is meaningful. It is only the outcome of the interplay of these factors that has significance as an incentive or disincentive.

Combined royalty and federal and provincial tax take can vary from about 45% to 70% of the gross revenue from a barrel of oil in

Alberta depending on circumstances. At these levels it is clear that royalty and taxation factors are the dominant variable in establishing the economic incentives of the industry. It is essential, therefore, to understand the royalty and taxation framework as background for any evaluation of specific incentive programs. In fact, many of the elements of the incentive systems reviewed involve programs relating to royalty and tax treatment.

Oil and Gas Pricing

The emerging Canadian government energy policy of the middle 1970's was to move Canadian oil and gas prices to world levels as rapidly as possible, with the limitation that the Canadian price not exceed the average U.S. oil price. The announced program did not move the Canadian oil price to today's world price but it did result in an approximate \$1 per barrel increase in oil prices roughly every six months through the latter half of the 1970's. Crude oil prices moved from \$3.80 per barrel at the start of 1974 to \$14.75 per barrel at the beginning of 1980.

Natural gas prices have followed a similar trend. Natural gas prices are set by federal-provincial agreement, which since November 1975 has set a Toronto City Gate Price. The Alberta border price is the Toronto City Gate price less the cost of transportation between the Alberta border and Toronto, as established by the National Energy Board. The National Energy Board also sets the prices for natural gas exported from Canada. Export prices have been set higher than the

Alberta border price. Each Alberta producer receives a pro rata share of the higher value of export gas and such price adjustment is added to the Alberta border price to determine the regulated field price for natural gas in Alberta.

More important to exploration than the price trend however, is the course of netbacks to the producer for each barrel of oil or mcf of gas produced. The producer netback is the cash income available to the producer after all tax, royalties, and other expenses associated with production and sale of the oil or gas. Producer netbacks have improved progressively also, particularly since 1974.

Figure 1 presents Alberta crude oil prices and also traces estimated producer netback on both 'old' and 'new' oil. 'Old' oil is defined as oil discovered before April 1, 1974, whereas 'new' oil is oil discovered after this date. As will be further discussed under Royalties, new oil carries a lower Alberta Provincial Royalty than old oil which explains the difference in netback exhibited in Figure 1.

Figure 2 presents price and netback trends for natural gas production in Alberta. As in the case of crude oil a lower royalty rate on new production yields a higher netback.

It is important to note that the netbacks shown are minimum netback values to the producer because they reflect a producer in a fully taxable position. To the extent that corporate income tax is sheltered by past investment, cash producer netback values are understated. The degree of understatement would of course vary with the tax position of

each individual producer and is highly influenced by the rate of on-going reinvestment. The netback on Figs. 1 and 2 assume no reinvestment. Under Canadian tax law expenditures on exploration and development are deductible items for federal income tax purposes. (See Table 3 Canadian Taxation). Such expenditures therefore, act to reduce federal income tax payable resulting in a higher netback available to the producer. Exploration expenditures are 100% deductible, development expenditures are 30% deductible on a declining balance basis, and both exploration and development expenditures earn depletion allowance credits. The impact of expenditures on netback can be highly significant. The tabulation below illustrates this impact for an average producer operating in Alberta for the last half of 1979. It should be noted that

IMPACT OF RE-INVESTMENT EXPENDITURES ON

PRODUCER NET-BACK ON OLD AND NEW OIL

ALBERTA - SECOND HALF 1979

	<u>With No Re-Investment</u>		<u>With Re-Investment of \$2.50/bbl Exploration & \$1.50/bbl Development</u>	
	<u>Old Oil</u>	<u>New Oil</u>	<u>Old Oil</u>	<u>New Oil</u>
Gross Revenue/bbl	\$13.75	\$13.75	\$13.75	\$13.75
Operating Costs	(1.30)	(1.30)	(1.30)	(1.30)
Provincial Royalty	(5.95)	(4.23)	(5.95)	(4.23)
Net Prov. Tax	(0.24)	(0.43)	(0.24)	(0.43)
Federal Income Tax	(3.36)	(3.36)	(1.82)	(1.82)
	<u> </u>	<u> </u>	<u> </u>	<u> </u>
Producer Net-Back	<u>\$ 2.90</u>	<u>\$ 4.43</u>	<u>\$ 4.44</u>	<u>\$ 5.97</u>
Improvement in Net-Back %			+53%	+26%
Net-Back as % of Gross Revenue	21.1%	32.2%	32.3%	43.4%

higher levels of reinvestment than used in the above example will yield even higher netbacks. Most companies operating in Western Canada have relatively high reinvestment rates. The \$2.50/bbl exploration expenditure and the \$1.50/bbl development expenditure approximate average industry expenditure levels, and thus the reinvestment returns tabulated above are representative for those companies spending at an industry average rate relative to their production level. In the above example the producer realizes an increment to netback of \$1.54/bbl on an incremental investment of \$4.00/bbl, or a return on incremental investment of 38.5%. This provides a significant motivation for reinvestment, in particular for exploration activity.

There is of course a complete range of reinvestment among different operators and each one will have their own particular tax circumstances. It is therefore not possible to determine an average netback after reinvestment. On the basis of a number of theoretical calculations of netback, using different reinvestment rates for different time periods throughout the middle and late 1970's, it is possible to postulate a general range of netback values in which most producers will likely fall. This area of netback values is represented on Figures 1 and 2 by the shaded areas. Even though this range is only a calculated estimate of netback the shaded areas are more representative of actual experience than the no reinvestment case.

The preceding analysis does not take into account the effect of special incentive programs such as Alberta's Exploratory Drilling

Incentive Credit system or the Geophysical Incentive Program. Under these programs an operator can earn credits against royalties and taxes due to the province and to the extent that these are earned the producer's cash position is further enhanced. While such credits are not specifically related to netbacks on production they act in the same manner as reinvestment to enable the producer to retain a higher net cash return on gross revenue.

Provincial Royalty Systems

Almost all Canadian oil and gas production comes from the three western provinces of Alberta, British Columbia, and Saskatchewan. In all three provinces, production from Crown lands of both oil and gas is subject to different royalty schemes for 'old' and 'new' production on the basis of a 1974 date in order to distinguish between oil and gas developed in a higher cost environment in later years. Provincial royalties are a function of both price and volume produced. For example, in Alberta, allowances are made for the volume of production so that stripper wells pay a reduced royalty of zero to 10% while high volume producers of 'old' oil are assessed at an incremental royalty rate of 50% and 'new' oil carries an incremental royalty rate of 35%. British Columbia has somewhat lower rates and Saskatchewan somewhat higher.

For gas, the royalty system in Alberta is similar to that for oil. In British Columbia and Saskatchewan all gas is sold to Crown corporations

at royalty-free but controlled prices, which usually are below comparable Alberta prices.

The collection of royalties is the producing provinces principal source of direct revenue from oil and gas production within the province. Royalty rates have been adjusted frequently since oil and gas prices began to move up in 1973. The dates and details of the royalty changes are listed in Appendix A, Tax and Royalty Changes. Each producing province has sought, mainly through an adjustment of the royalty rate, to extract what it considered to be its appropriate share of the economic rent resulting from the rising trend of prices for oil and gas. Similarly, the federal government has sought to protect its share of the higher revenues. This has frequently led to disputes between the federal government and the producing provinces over appropriate price and taxation levels creating periodic uncertainties for industry with respect to these most fundamental economic factors of their business.

The most critical of the federal provincial revenue sharing disputes occurred in 1974 when provincial royalties on oil and gas were increased to capture some 60% to 100% of the increase in the price of oil from \$3.80/bbl to \$6.50/bbl. At that time provincial royalty was an expense for federal income tax purposes, and this meant that the provincial governments were capturing the bulk of the economic rent from higher prices largely at the expense of any federal government share. The federal government consequently announced that royalties would no longer be deductible as an expense in income tax calculations, thus restoring their

participation in the higher revenues. This left the producer squarely in between the two levels of government facing a situation of double taxation. Essentially there was \$2.00/bbl of economic rent to be captured and both the provincial and federal governments took it.

The result of the competition between both levels of government trying to capture as much as possible of the rising oil revenues was a major disincentive for the industry. The economic negative reached the extreme in Saskatchewan where for every \$1/bbl price increase royalty and tax payments by the producer went up by more than \$1/bbl. Beyond that was the important psychological uncertainty overshadowing the industry regarding its fundamental relationship with its governments. The result was predictable; exploration activity - geological, geophysical, and drilling activity - declined as companies took to the sidelines to await resolution of their political and economic environment.

Between December 1974 and June 1975 a number of changes were introduced at both provincial and federal levels which brought about a correction to the events of 1974. In December 1974 Alberta introduced its Petroleum Exploration Plan which effectively reduced royalties on oil and gas, established a rebate of higher provincial taxes due to the disallowance of royalties, and established a royalty tax credit to offset up to one million dollars of the higher federal taxes resulting from non-deductability of royalties. The Plan also increased credits under the Exploratory Drilling Incentives system. Other provinces also acted to effectively reduce incremental royalty rates. In mid-1975 the

Table 2

PROVINCIAL ROYALTY REGULATIONS

(1979)

Alberta Old Oil Royalties

- * Are graduated with both price and production rate since April 1, 1974.
- * At current \$13.75/B price, the average crown royalty rate is 43.2% (well producing 3,600 barrels per month).
- * The current average royalty may be summarized as 21.7% of \$4.40/B select price, plus 65% of next \$2.10/B, plus 50% of \$7.25/B.

Alberta New Oil Royalties

- * Oil discovered after April 1, 1974 or additional recovery from an enhanced recovery scheme approved after January 1, 1974.
- * Marginal rate averages 35%.
- * Calculated: 21.7% of \$4.40/B + 35% of \$9.35/B.

Alberta Old Gas Royalties

- * Are graduated with price for wells producing more than a monthly average of 250 Mcf/d: 22% applicable to first 26¢/MCF, with escalating rates on the next 10¢/MCF. A royalty of 50% is applicable to the portion of the price above 36¢/MCF.
- * For wells producing less than 250 Mcf/day, royalties are graduated with both price and production since August 1, 1978. Royalty rate ranges from 5% (zero production) to the rate applicable to higher deliverability wells at 250 Mcf/day.

Alberta New Gas Royalties

Gas initially produced for sale after January 1, 1974.

- * Graduated with price for wells producing more than 250 Mcf/day: 22% applicable to first 26¢/MCF, with escalating rates on the next 10¢/MCF. A royalty of 35% is applicable to the portion of the price above 36¢/MCF.
- * For wells producing less than 250 Mcf/day, royalties are graduated with both price and production since August 1, 1978. Royalty rate ranges from 5% (zero production) to the rate applicable to higher deliverability wells at 250 Mcf/day.

Table 2

PROVINCIAL ROYALTY REGULATIONS (continued)

Saskatchewan Old Oil Royalties

- * Are graduated with production but factors change with each price increase.
- * Current average royalty is about 48% including the 1% road allowance charge (well producing 23 barrels per day).
- * Royalties are deductible from tax payable under the Oil Well Income Tax Act which came into force September 1, 1978 but is retroactive to January, 1974.
- * Oil well income tax is calculated on a well-by-well basis or larger units where appropriate) and applied on revenues from the wells, less certain expenses. Announced tax rates are:

1974 - 80%	1976 - 77%	1978 - 60%
1975 - 77%	1977 - 70%	1979 - 59%

Saskatchewan New Oil Royalties

- * Oil reserves recognized after 1973 or production from infill wells completed after 1973.
- * Royalty levied at 66% of the rate for old oil and deductible from oil well income tax. Oil well income tax levied at 70% of rates for old oil.

British Columbia Old Oil Royalties

- * Are graduated with production rate.
- * Royalty may be summarized as 12% of the first 600 barrels per month, plus 40% of the remaining production. Average royalty is about 29%.

British Columbia New Oil Royalties

- * Oil reserves recognized after November 1975.
- * Royalty may be summarized as 15% of the first 1000 barrels per month, plus 30% of the remaining production.

British Columbia Old Gas Royalties

- * British Columbia Petroleum Corporation is sole buyer since late 1973.
- * Price is \$.78/MCF on a royalty-paid basis effective November 1, 1977. Price is subject to certain adjustments to maintain the level of after-tax revenues to the producer.

British Columbia New Gas Royalties

- * Gas reserves recognized after November 13, 1973.
- * Price is \$1.03/MCF on a royalty-paid basis effective November 1, 1977. Price is adjusted in the same manner as old gas.

federal government introduced the 25% Resource Allowance as an expense deduction to partially take the place of the non-deductability of provincial royalties. This completed the adjustment to the confrontations of 1974 and industry exploration activity began to pick up once more. Since that time royalty changes have coincided with price increases or changes related to low productivity, enhanced recovery, experimental, or specific incentive programs.

The present royalty structure in Alberta is summarized below.

Alberta Royalty System

<u>Crude Oil Royalties</u>	<u>Average Royalty Payment</u>
Old Oil	43.0%
New Oil	28.5%
Enhanced Recovery	0 to conventional rate
Experimental Projects	5%
Exploratory Wells	5 Year 'holiday'
<u>Natural Gas Royalties</u>	
Old Gas	43.8%
New Gas	31.7%
Exploratory Wells	1 Year 'holiday'

A more complete description of the royalty systems in effect in Alberta, Saskatchewan, and British Columbia is presented on Table 2, Provincial Royalty Regulations.

Canadian Oil and Gas Taxation

The major features of Canadian oil and gas taxation are summarized on Table 3. Additional discussion of some of the significant aspects follows.

Table 3

CANADIAN OIL & GAS TAXATION SUMMARY

Income Taxes

* Major features of the current system reflecting the changes embodied in the November 18, 1974, June 23, 1975, March 31, 1977 and April 10, 1978 and November 16, 1978 federal budgets are:

- Net federal tax rate 36%.
- Royalties and lease rentals paid to the provincial or federal Crown are not deductible after May 6, 1974.
- 25% resource allowance in lieu of royalty deductibility (calculated on 25% of gross revenues less operating costs and capital cost allowance (CCA)).
- Depletion allowance deductions of:
 - (a) the lesser of 33-1/3% of exploration and development drilling expenditures or 25% of resource income;
 - (b) the lesser of 50% of enhanced recovery facility investments (conventional oil tertiary projects and the tangible injection and production facilities for in situ oil sands plants) or 50% of corporate resource and non-resource income after deduction of (a) above (April 10, 1978 Budget);
 - (c) in addition to (a) above, 66-2/3% of the costs in excess of \$5 million for exploratory wells drilled before April 1, 1980 (March 31, 1977 Budget).
- Expenditure write-offs are:
 - (a) Immediate for exploration;
 - (b) 30% diminishing balance for development drilling and production facilities;
 - (c) 20% diminishing balance for gas plants which do not qualify for 2 year manufacturing and processing fast write-offs.

- Example Federal Tax Calculation:

Tax = 36% (revenue - operating costs - CCA - resource allowance - Canadian exploration and development expenses - depletion allowance)

Where: Resource allowance = 25% (revenue - operating costs - CCA)

Depletion allowance = lesser of 33-1/3% of eligible expenditures or 25% of resource income, plus 66-2/3% of exploration well costs in excess of \$5 million.

Resource Income = revenue - operating costs - CCA - resource allowance - Canadian exploration and development expenses.

- * Provincial tax rates: Alberta 11%, Saskatchewan 14%, British Columbia 15%.
- * All provinces use federal tax base except: Alberta, Saskatchewan and British Columbia allow deduction of royalties for provincial tax purposes in place of the resource allowance.

Taxable income for any company in Canada is determined by deducting from gross revenue various allowed deductions such as operating costs, interest, administrative overheads and associated direct expenses. Allowable costs for oil and gas companies include the following deductions.

Capital Cost Allowance (CCA) is a method of calculating depreciation, generally using a declining balance method. The federal government has established 35 classes of CCA and assets are depreciated according to the class rate. Some typical class rates are:

Production Equipment such as tubing, sucker rods, wellheads, gathering systems and small plants, etc., are given a CCA rate of 30% per year.

Equipment, buildings, pumps and compressors that are otherwise not specifically classified generally are given 20% per year.

New Investments in certain types of projects can be written off faster. Canadian-built drillships and icebreakers are given a straight line writeoff over 3 years while processing plants that extract NGL's or sulphur are given 2 year straight line rates.

Investment Tax Credits (ITC). To encourage investment in new plants and facilities, the government gives an additional writeoff of 7% of the cost of a new project (10% to 20% if made in certain economically depressed areas) that can be taken off taxable income. The amount

reduces the asset value for CCA purposes. ITC's can be earned for any new investment in equipment or facilities, for exploration, production or processing. ITC's can only be carried forward for 5 years, at which time they lapse.

Canadian Exploration Expenses (CEE) are fully deductible expenses that can be written off in the year in which they are incurred or can be carried forward indefinitely. This category includes all geological, geophysical, drilling and associated intangible costs of exploration wells, the first well in any field, or wells that are incapable of production for one year.

Canadian Development Expense (CDE) includes the intangible costs of development wells that are deductible at 30% per year on a declining balance basis. This rate also applies to all land and property acquisition costs. Both CEE's and CDE's can be used in the year they are incurred or carried forward.

Depletion Allowances. There are three types of depletion allowances that can be taken against income flow in Canada. These are as follows:

Earned Depletion (ED) Depletion is earned at the rate of \$1 for every \$3 of qualifying expenditure. Thus exploration and development costs (excluding land and property acquisition costs) earn an extra deduction of 1/3 of the total expenditures against taxable resource income up to 25% of taxable income in any year. Earned depletion credits can be carried ahead indefinitely.

Frontier Depletion. Drilling in frontier areas such as the Beaufort Sea or other Canadian offshore areas is eligible for "super" depletion for an extra 2/3 of total expenditure. This is limited to amounts over \$5 million per well, but unlike earned depletion, it can be written off in full against other income (ie, it can be treated like CEE's).

Tertiary Depletion allows a writeoff of 50% of production equipment, related facilities and additional drilling costs for any tertiary recovery project.

Resource Allowance is the federal government's method of compensating oil and gas producers for the payment of provincial royalties and is used in calculating their federal income tax. The resource allowance allows 25% of gross profits on production to be deducted for federal tax calculations as an offset to provincial royalties. Consequently at the standard corporate tax rate of 36%, the effective rate of federal tax on resource income is lowered to 27%.

Non-Principal Business Deduction. To encourage the flow of funds from individual investors, exploration expenditures may be written off against personal income for tax purposes at the rate of 100%. This feature of the Income Tax Act has attracted significant contributions to petroleum investments, particularly by taxpayers in high marginal tax brackets.

Impact Of Pricing, Royalty and Tax Policies

The tax arrangements in place for the oil and gas sector in Canada are intended as more than a government-industry revenue sharing mechanism. There are powerful investment incentive features embodied in the tax structure and these provisions play a key role in directing energy policy towards promoting exploration and development objectives. The taxpayer who would otherwise be burdened by taxes due the government can use the credits generated from investments to reduce or eliminate those taxes (especially in the case of federal taxes), thereby reducing the up-front cost of his oil and gas investments. As has been discussed the oil and gas taxation system provides an array of specific incentives relating to particular types of investment. These act to improve the cash position of the investor and can be viewed as either a reduction in his investment cost or an enrichment of his production netbacks.

It must be noted however that two conditions are essential to realize the investment incentive provisions. The investor must have an income stream from which to deduct the expense credit generated by his investment. Furthermore he must be in a tax paying position in order to realize the value of his qualifying deduction. This system tends to favor already established entities who can maximize the deductions from corporate income tax flowing from both past and on-going investments. New entrants to the industry who are without taxable income are at a competitive disadvantage. The existing business, with an ability to make an immediate tax write-off, has effectively a lower

after tax cost of investment or expenditure. Therefore, the existing company has a competitive advantage in being able to make higher bonus bids for land, offer better terms for farm-ins, and explore at a lower cost. This is one of the reasons why entry into the oil and gas business in Canada commonly takes the form of acquisition of existing production or acquisition of an established firm. This latter trend has been particularly strong over the past approximately two years. It should be emphasized, however, that petroleum properties acquisition has been spurred by the financial attractiveness of rising profits, and higher values of reserves and land, in addition to the associated tax credits and write-offs.

The potential of the tax system to reduce the effective up-front cost of an investment will depend on the type and amount of credit generated by the investment and whether or not the investor has enough taxable income against which to write-off immediately the credits available. To the extent that tax savings can be maximized, project rate of return will be enhanced commensurately. As a measure of the value of the tax savings, Table 4 shows the net discounted costs, after combined federal and provincial income tax, of a unit investment in various types of assets, for a taxable corporation with resource income in Alberta. The variations across provinces differ only marginally and basically result from varying provincial tax rates, with the lowest after tax costs being associated with the highest tax rates. Of particular interest is the wide variation between types of

Table 4

PRESENT VALUE OF AFTER-TAX COSTS OF \$1 INVESTMENT

(Investment Tax Credit 10%, Discount Rate 10%)

Fully Taxable Company - Alberta

<u>Investment</u>	<u>Flow-Through Basis</u> (Immediate Write-Off of Project Investment Against Other Income)	<u>Non-Flow Through Basis*</u> (Write-Off of Project Investment Against Project Income)
Exploration	.37	.60
Development	.46	.60
Well Equipment	.62	.73
Energy Mining	.48	.64
Operating Cost	.62	n.a.
Manufacturing	.55	n.a.
Enhanced Recovery Equipment	.41	n.a.
R&D (Manufacturing)	.35	n.a.
Well Costs above \$5mm	.06	n.a.

n.a. not available

*Assumes 'average' project characteristics in times of tax incidence (5 year delay).

Note: Provincial Incentive Credits are not included in the above calculation.

Source: Taxation and Revenue Sharing, Financial and Fiscal Analysis Branch,
Economic and Policy Analysis, Department of Energy, Mines and Resources,
Ottawa, Canada. November 1979.

investment, all of which carry differing types and degree of risks and rewards. The potential savings are appropriately graded so that the highest risk expenditures receive the greatest degree of incentive. The extreme example arises in the case of high cost exploration wells, mainly in the frontier areas where expenditures above \$5 million may result in a taxpayer having a tax saving greater than his investment.

The Table also shows the effect on discounted after tax cost between an investor who can take an immediate tax write-off and one who can only realize the tax benefits against income deriving from the project in which he is investing. If tax savings can be taken immediately against existing current income instead of deductible only when the project in question generates income, the effective cost of investment is substantially reduced, particularly where expenditures also earn depletion credits such as in exploration and development.

The investment costs on Table 4 do not include the value of provincial incentive credits. These credits can further reduce the investment costs shown, particularly in the area of exploration expenditures. In Alberta credits earned for drilling incentive exploratory wells can be up to 35% of costs. In projects where the maximum credit could be earned, in combination with the available income tax incentives, the net cost of investment in a project could be very low or even negative. While the richness of the incentives contributes to increasing the level of energy exploration, it can also lead to inefficiency to the extent that investors attempt to maximize tax benefits rather than minimize costs.

In terms of degree of motivation to stimulate activity and investment in oil and gas the tax system is clearly the principal incentive. This is true even in the area of exploration spending where the provincial incentive schemes have focused. For companies able to take an immediate write-off of expenditure the after tax cost of exploration in Alberta is 37¢ per \$1 expended. Thus a dollar spent on exploration earns an effective tax credit of 63¢. In the most favorable case under Alberta's Exploratory Drilling Incentive Credit program \$1 spent on exploratory drilling earns a maximum credit of up to 35¢.* While the Alberta exploratory credit is incremental to the income tax credit, the Alberta credit is only 55% of the income tax credit. Furthermore, the income tax credit can be generated on all qualifying exploration spending, whereas the Alberta provincial credit covers a more limited spending pattern relating to qualifying exploratory wells only. In order to place provincial incentive systems in perspective with the importance of the income tax structure package, the revenue distribution between federal, provincial and industry sectors is compared with the annual value of the incentive credits in Alberta on Table 5. The revenue figure is for the petroleum production sector only. The Alberta incentive credit figures include exploratory drilling credits, the value of royalty exemptions, and geophysical incentives. The total value of all incentives in the Alberta provincial programs is but a small fraction of the income, profits, or federal or provincial tax take for the producing sector of the industry. Clearly, therefore, the provincial incentive programs are not a principal motivator of

* On average for most of the EDICP programs. Regulations introduced in 1978 permit up to 75% of average costs for incremental footage below 17,000'.

Table 5

DISTRIBUTION OF PETROLEUM PRODUCTION REVENUES
vs AMOUNTS OF ALBERTA INCENTIVE CREDITS

	Net Operating Income Production	Federal Share		Provincial Share		Producer Share		Alberta Incentives
	<u>(\$mm)</u>	<u>\$mm</u>	<u>%</u>	<u>\$mm</u>	<u>%</u>	<u>\$mm</u>	<u>%</u>	<u>\$mm</u>
1970	1277	46	(3.6)	346	(27.1)	885	(69.3)	-
1971	1467	70	(4.7)	406	(27.7)	991	(67.6)	-
1972	1725	91	(5.2)	441	(25.6)	1193	(69.2)	-
1973	2495	182	(7.3)	681	(27.3)	1632	(65.4)	13
1974	4194	417	(9.9)	1601	(38.2)	2176	(51.9)	17
1975	5270	550	(10.4)	1928	(30.6)	2792	(53.0)	33
1976	6311	658	(10.4)	2572	(40.8)	3081	(48.8)	59
1977	8081	941	(11.6)	3802	(47.1)	3358	(41.3)	88
1978	9189	876	(9.5)	4254	(46.3)	4059	(44.2)	114

Source: Taxation and Revenue Sharing
 Financial Fiscal Analysis Branch,
 Economic and Policy Analysis,
 Department of Energy, Mines and Resources,
 Ottawa, Canada. November, 1979

Alberta Energy and Natural Resources,
 Edmonton, Alberta

industry activity but an incentive that operates at the margin only. The combined federal and provincial share of revenues has been in the 50 to 60% range in recent years. At these levels, small changes in the provincial or federal government take can have an impact far more significant than the impact of the special incentives programs. The value of the Alberta incentive programs for example has been about 1% of net production income for the 1976 through 1978 period. Thus the incentive programs are a minor factor in the total cash flow of the producing industry. Pricing, provincial royalty, and federal tax policies largely determine aggregate industry cash flow. Provincial incentives, as will be discussed, do play a more significant role in motivating certain specific activities such as exploratory drilling. However, in the context of the Canadian producing industry situation in the late 1970's, the provincial incentive programs are not a prime motivator or determinant of cash flow for the producing sector.

V ALBERTA EXPLORATORY DRILLING INCENTIVE CREDIT PROGRAM (EDICP)

The province of Alberta introduced the Exploratory Drilling Incentive Credit Program (EDICP) in 1972 to stimulate the discovery of crude oil reserves and shift exploratory activity back to the province. The program provides for the earning of a credit for expenditures incurred in drilling certain exploratory wells. The credit earned can then be used to offset cash obligations due the province such as royalties, rentals or bonuses. The program has undergone several modifications since its introduction. The program appears to have been successful in initiating an upturn in exploratory drilling. The upturn was sustained in the latter 1970's by favorable fundamental economic factors and an exceptionally favorable success ratio for new discoveries.

Reasons For The EDICP

Beginning in the latter part of the 1960's a major shift in exploration focus was taking place in the Canadian oil industry. Exploration activity was moving away from the provinces to federally controlled frontier areas.

Canada's frontiers - especially the north, the McKenzie Delta area and the Arctic Islands - looked particularly attractive in the late 1960's. Western Canada's last major oil discovery had been made in 1965 at Rainbow Lake, Alberta. Alberta was considered in a mature stage of development with the good prospects having been picked over and only smaller targets

remaining. Furthermore, Alberta already had more oil than it could produce. Alberta exports to the U.S. were market limited and rationing was in effect limiting production to about 60% of capability.

The final impetus in moving the search for 'big oil' to the new frontiers was the discovery of Prudhoe Bay in 1969. Not only did Prudhoe Bay add to the attractiveness of the frontiers but it was expected that Prudhoe production would further restrict crude oil exports from Alberta. Therefore starting in 1969, the industry, especially the majors, moved their exploration activities to the frontiers.

The fact that it was the majors that moved their activities to the frontiers and out of the province of Alberta was of particular significance to Alberta because the majors were very much the dominant factor in the whole industry in Alberta at that time. The majors were the largest land holders in the province and their lands were not being explored. Furthermore the majors were the largest producers in the province and certain major oil companies were seen as withdrawing excessive revenues from Alberta which were going to finance exploration elsewhere. Alberta wanted to assure that those companies would reinvest an appropriate share of Alberta revenues in further exploration in the province. Thus one of the goals of the EDICP was to have the majors spend a reasonable share of their profits in Alberta for the benefit of Albertans.

A second reason behind the EDICP was a political-economic one. A Conservative government had come to power in Alberta in August of 1971 after 36 years of Social Credit power. The new government, in seeking higher revenues, targeted an additional \$70 million to come from the oil industry. The 10-year oil royalty agreement signed in 1962 was up for review at that time and it was decided to raise the \$70 million by increasing oil royalties to a maximum of 25% from 16-2/3% effective January 1973. The government realized the industry was not in a position to deliver these revenues without an offset of some type. This was particularly true in light of the drop already being experienced in exploration activity which was having a negative economic impact on the whole province. The government therefore provided a means, through EDICP, whereby the oil companies could get back some of their money by exploring within the boundaries of Alberta.

Figures 3 and 4 describe the background to EDICP and some of the effects of the program. Figure 3 shows oil industry exploration and land acquisition expenditures in Alberta and the federal areas. Expenditures had plateaued in Alberta in the 1967 to 1969 period, and actually declined in 1970 and 1971 while expenditure levels were increasing annually in federal areas. Figure 4, the number of exploratory wells drilled in Alberta and federal areas, shows an approximately similar pattern. Note that in both cases activity levels do not really pick up until after 1975 when the federal provincial taxation disputes of 1974 got resolved.

Figure 3

EXPLORATION AND LAND ACQUISITION EXPENDITURES

Alberta and Federal Areas

Figure 4

EXPLORATORY WELLS DRILLED

Alberta and Federal Areas

Figure 5 is a more detailed breakdown of exploratory expenditures in the province of Alberta. Note particularly that the decline in spending between 1969 and 1970 falls mainly in the area of land acquisition which alone showed a \$63 million decline. Since the province of Alberta owns nearly all the petroleum and natural gas rights for sale in the province, this was essentially a drop in direct government revenues and the magnitude of the decline can be compared with the \$70 million revenue raising target of 1972. Although expenditure levels did pick up after the initiation of EDICP in late 1972, the big increases did not come until after the federal provincial conflicts of 1974 were resolved in 1975.

Development of EDICP Regulations

The EDICP was introduced as a part of the Alberta Natural Resource Revenue Plan and became effective August 1, 1972. A complete description of the Exploratory Drilling Incentive Regulations is contained in Appendix B. The EDICP is administered jointly by the Alberta Department of Energy and Natural Resources (ENR) and the Alberta Energy Resources Conservation Board (ERCB). The determination of qualifying footage or certification of a well as an incentive exploratory well is made by the Board. Determination of the credit to be established is made by the Department. As shown on Figure 6, the historical development of the program has followed four stages:

INDUSTRY NET CASH EXPENDITURES ON EXPLORATION - ALBERTA

FIGURE 5

Source: Cdn Petr.
Assoc.

Stage One: August 1, 1972 to December 31, 1973

The initial regulations related only to wells classified by the ERCB as New Field Wildcat. Approximately 30% of the cost of the well could be established as a credit. The total footage of the well was eligible. A five-year royalty 'holiday' was granted to these wells. Credits could be used to offset payments due the province for royalty, rental or mineral taxes.

Stage Two: January 1 to December 31, 1974

The original program was expanded by mechanical rule to include remote New Pool Wildcats and Deeper Pool Footage. Class A and B footage was established and up to 40% of deep footage cost was eligible for credit. The province was divided into Foothills, Northern, and Plains regions to recognize differences in costs. A two-year royalty holiday was granted for natural gas wells. The credit was expanded to cover bonus bids as well as royalties, rentals or mineral taxes.

Stage Three: January 1, 1975 to December 31, 1977

Incentives were increased by increasing the recognized well costs and by increasing the credit support for Class A and B footage to 50 and 37½%, respectively. Geophysical incentives were implemented.

Stage Four: January 1, 1978 to Present

The drilling credit areas were redefined on the basis of new cost data. The upper 2000 feet of all wells were excluded from incentives but

DURATION OF INCENTIVE PROGRAMS

Source: ERCB

FIGURE 6

incentives were increased below 3500 feet and below 5000 feet the incentive is as high as 75% of cost. The royalty holiday for gas has been reduced to one year.

More detailed discussion of particular aspects of special features in each of the above stages follows below.

Stage One

Originally only New Field Wildcats qualified for incentives and an incentive well was defined as a New Field Wildcat well certified by the Board as an incentive wildcat well. The term New Field Wildcat is part of the standard Lahee system of well classification. Figure 7 illustrates a qualifying well. Well classification is a technical definition based on geological concepts and therefore it was difficult for an operator to know before he drilled how the Board would distinguish between a New Field Wildcat, and a New Pool Wildcat in cases where either category appeared warranted. This caused disagreements between the Board and operators when borderline conditions prevailed. Furthermore, the Board did not certify a well until after it was completed meaning that the operator did not know in advance of drilling whether or not he was drilling a qualifying incentive well. This uncertainty greatly reduced the incentive potential.

Credits established by regulations were not transferable although they could be allocated by negotiation among those with an interest in the well subject to a limitation that no more than 20% of the credit could go to any party who did not contribute to the actual cost of drilling

In part after A.A.P.G.
J.R. Pow
ERCB

INCENTIVE WILDCAT WELL

AUGUST 1, 1972 TO DECEMBER 31, 1973

FIGURE 7

the well. This was done to protect the smaller operators from the greater negotiating power of the large oil companies on farm outs.

The formula for the credit was designed to provide about 30% of the cost of a new Field Wildcat (see Schedule A, Appendix B). The credit earned was uniform for all areas of the province. The five-year royalty holiday on wildcat oil production exempted the drilling spacing unit of the well from the mineral tax. The program was scheduled to expire on December 31, 1977 with all credits to be used up by December 31, 1979. The time limitation was to encourage near term activity.

Stage Two

It was in this stage that the program was substantially refined and broadened to the point where it developed some significance. The program broadened the classification of qualifying wells to include certain New Pool Wildcats and exploratory footage of Deeper Pool tests. Of particular importance was the fact that the definition of a qualifying well was made mechanical as opposed to a subjective definition in the first phase. Qualifying wells were defined by the distance between the proposed well and pre-existing production or abandoned wells. The definitions are explained in Schedules A and B of Appendix B and diagramed on Figure 8. The likelihood of a well qualifying could be reliably established by the operator before submitting his license request to the ERCB and in any case the ERCB qualified or disqualified the well in advance of drilling.

EXPLORATORY DRILLING INCENTIVE SYSTEM

INCENTIVE EXPLORATORY FOOTAGE

JANUARY 1, 1974 TO MARCH 31, 1981

(EXCLUDING UPPER 2,000 FEET FROM JANUARY 1, 1978)

FIGURE 8

To relate the incentives more closely to risk, two classes of incentive footage were defined; Class A and Class B. Class A footage is exploratory footage of a Deeper Pool test where there is no well within $1\frac{1}{2}$ mile radius of the subject well. Class B footage is a Deeper Pool test where there is an abandoned well within the $1\frac{1}{2}$ mile radius. These definitions are more complete in Appendix B, Schedule D and E. These Schedules for Class A and B footage were changed in 1978 and currently Schedules F and G (Appendix B) apply. A description of Class A and B footage is presented on Figure 9.

The stage two revisions also recognized that drilling costs differed in different areas of the province and three different areas of the province were defined by Schedule C, Appendix B: The Foothills, Plains, and Northern areas . (See Figure 10 showing present credit areas including the Central area established in 1978). Drilling credits were different for each area. Class A credits were set to approximate 40% of the cost of drilling the somewhat more risky Class A footage in the appropriate area. The credits for Class B footage were arbitrarily set at $\frac{3}{4}$ of the Class A credits in each area.

Because not all industry participants had royalties, rentals, or taxes payable to the province the uses to which the credit could be applied was expanded to include bonus payments for leases. This particularly helped the new entrant who could use exploration credits to purchase more leases even in the absence of a production base.

TWO CLASSES OF QUALIFYING FOOTAGE (EXCLUDING UPPER 2,000 FEET)

FIGURE 9

Energy Resources Conservation Board

Stage Three

As a part of the Alberta Petroleum Exploration Plan announced in December 1974, the benefits of the EDICP were increased. The value of the credit was increased for each depth and each area. The increase was in recognition of the effect of inflation on drilling costs which was estimated at approximately 25% over the prior year. In addition, the percentage of actual costs supported by the program was increased. The credits were designed to correspond to approximately 50% of the cost of drilling in each designated area. Class B credit continued to be 3/4 of the credit adopted for Class A footage or approximately 37½% of costs.

The program continued to retain the December 31, 1977 drilling deadline and the December 31, 1979 cutoff date for using credits. Thus any operator contemplating drilling or lease acquisition would be influenced by the fact that he had a limited time to earn and utilize the credits.

Stage Four

The 1978 regulations extended the incentives and further modified their form. Instead of three areas, the new definitions recognize four areas (see Figure 10). The previous Northern area was split into two areas, Northern and Central after the ERCB analyzed well cost data and surface access conditions throughout the area. Drilling costs for a given depth were found to be comparable in the new Northern and Foothills

MAP SHOWING
DRILLING CREDIT AREAS

Alberta
ENERGY AND
NATURAL RESOURCES

FIGURE 10

areas. Schedules F and G (Appendix B) prescribe the same footage credit for the two areas. The new schedules recognize no credit for the uppermost 2000 feet of a well as no encouragement for shallow drilling was deemed necessary. On the contrary excessive drilling of shallow gas wells, for which there was limited market, represented an uneconomic use of industry effort and incentive credits. At a depth of 3500 feet the 1978 credits would equal the credits under the previous system. Below that depth, the support is higher than previous. At 5000 feet the new credits are some 1/3 greater than the old system. An 18,000 foot Class A well in the Foothills or Northern area will earn a credit of \$2,600,000. In the Plains it would earn a \$2 million credit.

The five-year royalty holiday for crude oil was changed to the first 60, not necessarily consecutive, months of production. The royalty holiday for gas was reduced from 2 years to 12 months. Operators might gain from the latter change because the 12 months did not have to be consecutive, a benefit considering possible interruptions in production.

New termination dates for the program were established. The date for drilling wells was extended to March 31, 1981, and the date to utilize the credits was extended to December 31, 1987.

VI ALBERTA GEOPHYSICAL INCENTIVE PROGRAM

The Geophysical Incentive Program was implemented on January 1, 1975 to stimulate the level of seismic exploratory activity in Alberta. The program provides for the establishment of a credit for expenditures incurred in conducting seismic operations which can be used to defray cash obligations due the province from oil and gas. The program provides varying credits for seismic operations conducted in different areas of the province. The program, administered by the Alberta Department of Energy and Natural Resources, originally was to expire on March 31, 1978. The program was extended from April 1, 1978 to March 31, 1980 although the credit was cut in half.

Reasons for Geophysical Incentives

Beginning in the late 1960's there was a sharp drop in geophysical activity in western Canada. Geophysical activity declined from the 1960's peak of 1,045 crew months in 1967 to a low of 391 crew months in 1972. After a temporary pick-up in 1973 to 468 crew months activity dropped again in 1974 to 355 crew months and declined even further in 1975 to 316 crew months before a turnaround began.

Of particular significance to Alberta was the shift of activity away from the province during the early 1970's. Between 1961 and 1967, close to two-thirds of Canada's geophysical activity occurred in Alberta. In 1968 and 1969, Alberta accounted for just over 60% of

total activity. However, in 1970, more Canadian seismic activity occurred outside Alberta than in Alberta and by 1972 Alberta's share of total activity had dropped to 26%. Geophysical activity in Alberta declined from 603 crew months in 1969 to only 122 crew months in 1972, a level only 20% of the 1969 rate. Although 1972 represented a bottom in Alberta geophysical activity, the recovery from that depressed level was not particularly strong as indicated below.

	<u>1969</u>	<u>1970</u>	<u>1971</u>	<u>1972</u>	<u>1973</u>	<u>1974</u>	<u>1975</u>
Alberta Geophysical Activity (Crew Months)	603	397	224	122	146	182	171

The geophysical industry, which was centered in Alberta, was clearly in a slump. A number of seismic crews had already left the country to work in the United States where conditions were more favorable and a number of operators were having difficulty keeping their crews and skilled technicians together. This came at a time when Alberta was seeking to augment its exploratory drilling incentives. Because of the close relationship between geophysical and drilling activities, it was found desirable to provide incentives for geophysical exploration. It was considered vital to maintain a high level of geophysical work to ensure the continuity of the search for new oil and gas reserves. Although these logical arguments were advanced as rationale for the geophysical incentive program they were secondary

to the need to have more employment of geophysical crews in the province of Alberta.

Geophysical Incentive Program Regulations

A complete description of the Geophysical Incentive Program regulations is contained in Appendix C. The principal features of the program are described below.

The program became effective January 1, 1975 and was initially scheduled to terminate on March 31, 1978. The termination date was later extended to March 31, 1980. (See Figure 6) The Geophysical Incentive Program is administered solely by the Alberta Department of Energy and Natural Resources.

In order to qualify for credit a seismic program must be certified in advance of the survey and the survey must be conducted in accordance with the standards of geophysical practices. The operator must turn over to ENR all the raw data, copies of tape, stack sections, and all operators' reports, upon completion of the survey and before a credit is established.

The incentive credits are determined from the following formula based on the number of miles of subsurface coverage and the area in which the survey is conducted:

$$\text{Credit (\$)} = 500 \text{ K M}$$

Where, M is the number of miles of subsurface coverage in an area and K is the incentive factor for the area of Alberta in which the program

was conducted. Figure 11 shows the geophysical incentive areas for Alberta. Surveys carried out in difficult terrain in the Foothills and Green Areas receive a relatively larger incentive credit than surveys carried out in the Plains region. The incentive factor is one for the Yellow and Plains region, two for the Green area, and three for the Foothills area. Credits initially, therefore, amounted to \$500 per mile, \$1,000 per mile and \$1,500 per mile for the above regions respectively. These incentive levels were attractive in relation to costs, especially for the efficient operators or those who cut corners expensewise. An amendment to the Geophysical Incentive Program effective April 1, 1978, resulted in a reduction of the credit by 50%. The present formula, therefore, is:

$$\text{Credit (\$)} = 250 \text{ K M}$$

The credit established was not transferrable but could be allocated by negotiation among those who contributed to the actual cost of conducting the seismic survey. The credits established could be used to satisfy royalties, rental, fees, bonuses or taxes due to the province. In addition, in recognition of the fact that some geophysical activity is carried on by specialized companies, a cash payment of the credit was permitted to licensees who proved they were not the registered owner of any provincial mineral rights. This was to take care of the seismic contractors who were not engaged directly in the oil business and therefore had no royalty, rental or bonus obligations against which to charge off the credit earned. Importantly, these

payments received the same exemption from taxable income as did credits applied against royalties or taxes.

The regulations provided that all geophysical information obtained from a qualified program which received an incentive credit, may be kept confidential for a three-year period. After the initial three-year period, however, the geophysical information and data must be made available to anyone requesting it at a cost of not more than 60% of the credit established. This provision was established to maximize the information value of the data generated under government sponsored programs. However, it also had the effect of causing some companies to refuse the geophysical incentives in order to protect the confidentiality of their data.

VII IMPACT OF ALBERTA INCENTIVE PROGRAMS

The impact of the Alberta incentive programs on exploratory activity is a complex assessment. The precise impact can not be quantitatively measured because the programs were introduced in a highly dynamic environment. From the introduction of the first incentive programs in 1972, to the present, such fundamentally important motivational factors such as pricing, taxation and royalty policies have been under constant revision. Thus it is not possible to isolate the cause and effect of any single parameter or the ensuing activity that resulted. There has however, been a substantial increase in the number of exploratory wells drilled and seismic crews working in the province of Alberta since the introduction of the incentive programs.

From the point of view of the Alberta government the incentive programs have been a great success in meeting the objectives stated at the time of the introduction of the programs. The Alberta government's objective was to encourage oil and gas producers to reinvest their profits in Alberta to promote the discovery of oil and gas reserves. Oil industry investment in Alberta has surged particularly in the 1976 through 1979 period. Significant new discoveries of oil, and especially of natural gas, have been established in the province. The direct financial return to the province from increased royalties and lease bonuses has greatly exceeded the cost of all the incentive program credits.

There are a number of possibilities that exist when exploratory drilling or seismic exploration is supported by an incentive program. These are:

- (a) The activity may have occurred even in the absence of an incentive program.
- (b) The activity may have not occurred without the incentive, and/or the activity may not be performed in the future without incentive support.
- (c) The timing of the activity was advanced to take advantage of the programs before their scheduled termination dates.

Elements of each of the above considerations appear to be applicable to the Alberta case in descending significance. However, even in cases where activity would have occurred without incentives, the existence of incentives enhanced the cash flow of the operators enabling accelerated activity. Beyond that, the incentives and their updating confirmed the Alberta government's interest and concern in maintaining a healthy industry directed at continuing exploration for new oil and gas reserves within the province.

Limitations of the Data

Detailed information was available on exploratory wells drilled in Alberta classified by well type such as New Field Wildcat, New Pool Wildcat or Deeper Pool Test. For each exploratory well type, the number of wells and total footage drilled was recorded, classified according to whether it

resulted in an oil well, gas well or abandonment. Although data was available on the number of successful oil or gas wells for each type of exploratory well, no data was available on the addition of reserves by type of exploratory well. There was no breakdown of how wells were distributed geographically throughout the Province.

Data on incentive wells was even more limited being restricted to only the total number of incentive wells drilled each year. There was no breakdown available of how many incentive wells were New Field Wildcats, New Pool Wildcats, or Deeper Pool Tests. Data was not available on the additions to reserves made by incentive wells either in total or by type of well. There was no geographic breakdown of the distribution of incentive wells within Alberta, according to the various incentive areas.

The fact that data was not available on incentive wells by exploratory type, by geographic area, and by amount of reserves added limited the scope of analysis and the quantitative results.

Impact Of EDICP On Drilling Activity

One of the objectives of the Alberta government in the early 1970's was to shift exploratory activity back to the province and this has been clearly accomplished.

Western Canadian Drilling Activity

Table 6 shows the number of wells drilled in the three main producing provinces of Canada and for all of Canada. Although Alberta was increasing its share of the total drilling, even in the early 1970's, its share

Table 6

CANADIAN OIL AND GAS DRILLING ACTIVITY

	<u>Alberta</u> <u>(# wells)</u>	<u>Saskatchewan</u> <u>(#wells)</u>	<u>British</u> <u>Columbia</u> <u>(# wells)</u>	<u>Total</u> <u>Canada</u> <u>(# wells)</u>	<u>Alberta as</u> <u>% of Canada</u> <u>%</u>
1970	1782	920	172	3151	56.5
1971	1984	761	186	3265	60.8
1972	2675	651	217	3827	69.9
1973	3517	660	173	4616	76.2
1974	3499	282	142	4201	83.3
1975	3652	275	80	4242	86.1
1976	5046	257	187	5690	88.7
1977	5120	534	332	6197	82.6
1978	5585	978	402	7170	77.9

Source: Canadian Petroleum Association
B. C. Energy, Mines and Petroleum Resources

of activity sharply increased beginning in 1972. From approximately 60% of all Canadian activity in 1971, Alberta accounted for nearly 90% of drilling by 1976. Alberta's share of activity declined in 1977 and 1978 as a result of an upturn of drilling in Saskatchewan and British Columbia following a number of years of decline or stagnation. The upturn in Saskatchewan is directly related to development well drilling in the province's heavy oil belt, and over 50% of the activity listed is for development wells in the average depth range of 2400 feet to 3100 feet. The pickup in British Columbia relates to both exploratory and development activity in the Deep Basin area in northeastern B.C. This area is an extension of the Deep Basin trend in Alberta where the discoveries in this trend were first made.

Table 6 also shows the effect of sharply increased provincial royalties in 1974 and the ensuing federal provincial conflict. The federal resource allowance was introduced in mid-1975 and became effective in January 1976. That factor, and other adjustments, brought about a revival of activity in 1976. As a province, Alberta adopted the most reasonable response to the overtaxation of 1974, and in addition, they augmented their already existing incentive programs. Saskatchewan made the least realistic response in terms of pricing and royalty structure

and British Columbia was somewhere inbetween. Thus by 1976 it was quite clear that of the three provinces Alberta offered the most favorable economic environment. On top of this Alberta offered the best exploration prospects and therefore the industry really had only one place to turn to and they concentrated on Alberta. This was particularly true for the independent sector of the industry. Saskatchewan had introduced a form of incentive program whereby exploration activity could earn credits against provincial royalties payable. This kept some major companies with meaningful production bases in the province active to some degree. The independents without a means of monetizing the credit, left the province. The Government of Saskatchewan adopted the view that the province was a mature area with little additional resource to be discovered and therefore they would maximize provincial revenues from the remaining production. This attitude also contributed to the exodus from the province.

The independents did not turn to B.C. because in general the wells are deeper and more expensive, and the risk somewhat higher. Furthermore, British Columbia is a predominantly gas prone area and natural gas was in surplus supply in Canada in the late 1970's and near term markets were not available. Therefore, it should be emphasized that events in neighboring provinces to Alberta tended to funnel exploration activities in to Alberta. Certainly a portion of the activity in Alberta related to the relative unattractiveness of other areas.

EDICP and Alberta Activity

Drilling activity in Alberta did exhibit strong growth through the 1970's and exploratory drilling also increased sharply. Table 7 shows data on exploratory wells drilled in Alberta in the 1970's. The Table also presents data on those wells that received an exploratory drilling credit. The data on Table 7 is presented graphically on Figure 12 in terms of number of wells, and in Figure 13 in terms of footage drilled, and also on Figure 14 which shows average well depth.

The EDICP became effective August 1, 1972, and initially applied only to New Field Wildcats. The number and footage of New Field Wildcats went up in 1972 from a low point in 1971 but it is unlikely that the major portion of that recovery was related to EDICP. The program was only effective for five months in 1972 and operators did not know in advance of drilling whether a well would qualify for incentives. 1973 was the first full year of phase one of the incentive program and although New Field Wildcats increased activity for all types of exploratory wells increased even more.

The data for 1974 is particularly interesting. Although the program was expanded on January 1, 1974 to include remote New Pool Wildcats and Deeper Pool footage, and credit increased up to 40% of cost from 30%, the number and footage of New Pool Wildcats and Deeper Pool Tests declined rather sharply. The expansion of EDICP in 1974 included dividing the province into three cost regions, establishing a two-year royalty holiday for gas, and adding lease bonuses to the application of the credit earned, but the broader and more generous terms of the program could not

Table 7

EXPLORATORY WELLS COMPLETED IN ALBERTA1970 - 1978 by Type

Type of Exploratory Well		1970	1971	1972	1973	1974	1975	1976	1977	1978
<u>NEW FIELD</u> <u>WILDCATS</u>	No.	282	256	405	424	457	350	336	321	230
	Footage (000')	1625.9	1211.9	2001.7	1937.3	1901.3	1357.3	1559.2	1544.7	1155.5
	Ave. Depth'	5766	4734	4942	4569	4160	3878	4640	4812	5024
<u>NEW POOL</u> <u>WILDCATS</u>	No.	621	636	592	838	626	698	1139	1244	1534
	Footage (000')	2518.2	2732.9	2505.6	3254.1	2572.8	2745.5	4124.9	5208.7	6841.5
	Ave. Depth'	4055	4297	4232	3883	4110	3933	3622	4187	4460
<u>DEEPER POOL</u> <u>TESTS*</u>	No.	42	41	52	264	146	186	585	721	537
	Footage (000')	57.5	55.7	65.4	247.7	157.1	186.9	487.1	708.1	803.1
	Ave. Depth'	1369	1359	1258	938	1076	1005	833	982	1496
<u>TOTAL</u> <u>EXPLORATORY</u>	No.	945	933	1049	1526	1229	1234	2060	2286	2301
	Footage (000')	4201.6	4000.5	4572.7	5439.1	4631.2	4289.7	6171.2	7461.5	8800.1
	Ave. Depth'	4446	4288	4359	3564	3768	3476	2996	3264	3824
<u>INCENTIVE</u> <u>WELLS**</u>	No.	--	--	190	365	650	700	860	1215	1173
	Footage (000')	--	--	800.0	1900.0	2184.9	2100.3	2872.0	2945.0	3600.0
	Ave. Depth'	--	--	4211	5205	3362	3000	3340	2424	3069
<u>INCENTIVE</u> <u>% OF TOTAL</u>	No. (%)	--	--	18.1	23.9	52.9	56.7	41.7	53.1	51.0
	Footage (%)	--	--	17.5	34.9	47.2	49.0	46.5	39.5	40.9

* Footage shown is exploratory footage only, i.e., footage drilled below deepest productive pool. Remainder of footage is classified as development well footage. Average depth is for exploratory footage only.

** Exploratory Drilling Incentive System introduced August 1, 1972.

Source: Canadian Petroleum Association, Statistical Handbook
Alberta Energy Resources Conservation Board

overcome the deteriorating economics of aggressive provincial royalties and tax take.

In 1975 incentives were again increased to subsidize a higher portion of the operator's drilling costs. In spite of the higher incentives, the number of exploratory wells, exploratory footage, and average well depth reached their lowest point since 1972. Although the number of wells being certified for credit had gone up each year, reaching 57% of exploratory wells drilled and 40% of exploratory footage, total exploratory drilling was not expanding. The sharp increase from 24% in 1973 to 57% in 1975 of incentive wells as a percent of total exploratory activity reflects two interrelated factors. On the one hand, industry was becoming more sensitive to the qualifications for wells to earn incentive credits and thus a higher proportion of their activity was qualifying. A second factor, relating specifically to the 1974 and 1975 environment, suggests that a greater proportion of wells that would not receive a credit were viewed as uneconomic or unattractive to drill. Therefore, although drilling activity levels declined in 1974 and 1975, the existence and improvement in Alberta incentives significantly mitigated the decline. In Alberta the number of exploratory wells drilled in 1975 approximated the 1972 - 1973 average. And the total number of wells drilled in the province set a new high. By contrast, in British Columbia and Saskatchewan, provinces without incentive programs, total drilling activity in 1975 plunged to approximately 40% of the 1972-1973 average level.

One of the features of qualifying wells was that they had to be at least 3 miles from a well with established production. Thus exploratory

EXPLORATORY AND CERTIFIED WELLS, ALBERTA

Source: ERCB

FIGURE 12

wells were carefully located with this in mind in order to qualify for incentives. A number of wells were drilled not on their best geologic location but rather at a compromise location to fit the definition of the incentive program. One of the reasons for broadening the program to new pool and deeper pool wells was that you soon run out of favorable locations within 3 mile diameter areas and that would negate the incentive program.

With the resolution of the federal-provincial revenue conflict, and the introduction of the federal resource allowance on January 1, 1976 exploratory activities picked up dramatically. As is illustrated on Table 7 and Figures 12 and 13, the greatest increase was shown in New Pool Wildcats. Much of this can be accounted for by the drilling of a large number of relatively shallow wells in blanket type gas sand deposits in Alberta. Some of Canada's largest gas fields in areal extent are in shallow Cretaceous sands which extend 50 to 100 miles in productive area at depths of a few thousand feet. This is typical of the Milk River - Medicine Hat shallow gas sand deposits found within southeastern Alberta and the Steen-Boyer area of northeastern Alberta. The existence of gas in these blanket sands is well known and not a discovery challenge. The Milk River field for example, was discovered in 1890. However, by locating wells 3 miles apart operators could qualify these wells for incentives as New Pool Wildcats. Collecting incentive credits for such low risk, low cost wells proved exceedingly popular. Since these wells did not need exploratory incentives the first 2000 feet of hole drilled was dropped from the incentive program in January 1978.

EXPLORATORY AND INCENTIVE FOOTAGE

Source: E&NR, ERCB

FIGURE 13

As shown on Figure 14, the average well depth was decreasing from 1972 through 1975. This reflected a combination of factors. The initial drilling incentive package was not depth sensitive and provided no particular bonus for deeper drilling. In addition, the predominance of drilling for shallow gas reduced the average depth numbers. Furthermore, the success ratio for drilling at the shallow depth was so good that the operators did not have to accept the higher risk and expense of deeper drilling. The substantial increase in well depth, especially for New Field Wildcats, in 1976, 1977 and 1978, reflects activity associated with the West Pembina discovery in 1977 and the Elsworth Deep Basin discoveries at about the same time. A number of the Deep Basin wells were drilled as New Pool Wildcats under the incentive program definition even though they were essentially development type wells in sands whose presence was well known.

The increase in number of exploratory wells (Figure 12) in the 1976-1978 period also reflects the West Pembina and Elsworth discovery booms. Particularly noteworthy is a decline in New Field Wildcats and a sharp increase in Deeper Pool tests. With respect to West Pembina, Devonian targets were categorized as Deeper Pool tests because their Devonian objective underlay the wide spread Cretaceous Cardium sand zone so prevalent throughout that area.

The independent sector of the industry was responsible for much of the pickup in activity. The Independent Petroleum Association of Canada estimated that the independents drilled 78% of all the exploratory wells

AVERAGE WELL DEPTH
FIGURE 14

Source: ERCB

drilled in Alberta in 1976. Without the incentives, and with no markets for natural gas, the independents would not have had the cash flow to continue that rate of exploration. The independent companies are typically cash short and therefore are more influenced by the high cash return aspect of the incentive program than by such bonus features as the royalty free period for discoveries. The incentive credits made it possible for independent companies to undertake more expensive wells at a lower net cost. With the rapid rise in drilling costs in the middle 1970's, the incentives were an important factor to the independents in keeping them from being priced out of the drilling business. Because of the high degree of success that the independents have enjoyed they are a much stronger sector today than they were five to ten years ago. Moreover, the independents have reached a size and financial maturity that makes the necessity for incentives less.

One of the intentions of the program was to stimulate additional deep drilling. Although the data on average depth (Table 7, Figure 14) suggests that this did not happen it should be pointed out that the deep drilling in Canada has been limited by rig availability and virtually every deep rig has operated at capacity for a number of years. Although deep wells do earn the highest incentives they are also the most expensive to drill and typically they have the highest potential for drilling problems which can create order of magnitude cost overruns. Therefore, this is an area of activity that is seldom engaged in by the independents in spite of the features of the EDICP. In addition, the deepest prospects are typically

gas prone and gas markets have been scarce. The lack of a better performance in drilling depth can probably be attributed to the limited number of participants, essentially the majors, and the limitation in drilling capacity.

Although early regulations may not have particularly helped deep drilling, the present regulations have provided substantial incentive since January 1, 1978. Currently it is possible for an investor to earn credits at certain deeper footages which exceed the net cost after tax relief of drilling at that depth. This has undoubtedly motivated some wasteful drilling which has been counterproductive.

On the other hand the program seems to have stimulated a great deal of shallow drilling activity. As was previously discussed, the classification of essentially step out wells as New Pool Wildcats in shallow blanket sand areas enabled independents to establish extremely favorable success ratios at a modest cost. On the plus side it can be said that drilling up very broad areas on three mile centers delineated the boundaries of these large fields much faster than might have been the case under more conventional drilling practice.

Success Ratios

While the establishment of the EDICP may have been the catalyst for getting the exploratory activity turned on again in the early 1970's, it was surely the success ratio that gave activity self-sustaining momentum in the late 1970's. We have previously discussed the overriding importance of price, and features of taxation and royalty, but none of these can

Table 8

SUCCESS RATIOS - ALBERTA EXPLORATORY AND DEVELOPMENT WELLS

	<u>1970</u>	<u>1971</u>	<u>1972</u>	<u>1973</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977</u>	<u>1978</u>	<u>Estimated 1979</u>
<u>EXPLORATORY WELLS</u>										
Oil	55	93	56	101	69	67	108	172	218	262
Gas	183	202	252	413	386	428	1004	1011	956	917
Total Exploratory	945	933	1049	1526	1229	1234	2060	2286	2301	1990
Success Ratio (%)	25	32	29	34	37	40	54	52	51	59
<u>DEVELOPMENT WELLS</u>										
Oil	249	268	458	474	571	593	442	531	728	898
Gas	434	489	748	1058	1298	1494	2189	1942	2134	2251
Total Development	802	977	1420	1763	2199	2321	2875	2777	3218	3595
Success Ratio (%)	85	77	85	87	85	90	91	89	89	88
<u>PROVINCIAL TOTAL</u>										
Oil	304	361	514	575	640	660	550	703	946	1160
Gas	617	691	1000	1471	1684	1922	3193	2953	3090	3168
Total Drilled*	1782	1984	2675	3517	3499	3652	5046	5120	5584	5600
Success Ratio (%)	52	53	57	58	66	71	74	71	72	77

*includes abandoned, service, suspended and miscellaneous wells

Source: Canadian Petroleum Association, Statistical Handbook
1979 Estimates from Oil Week

motivate without discovery. Table 8 shows the success ratio for exploratory and development drilling in Alberta through the 1970's. Although activity levels may not have been as high as desired in the early 1970's, the exploratory success ratio did show improvement each year. It was the resurgence of activity in 1976, however, that brought with it a truly remarkable improvement in exploratory success rate. The exploratory well success ratio jumped to 54% in 1976 from 40% in 1975. Even though this success came mainly in the natural gas area and certainly a part of it is attributable to the shallow blanket sand gas discoveries, it is nevertheless an unusually high exploratory success ratio. Such a high ratio in fact gives further credence to the contention that some of the exploratory New Pool Wildcats were no more than development type wells. The 1977 and 1978 discovery ratios reflect the discovery periods for the West Pembina and Elmworth areas.

A breakdown of success ratio by type of exploratory well is particularly revealing (Table 9). The success ratio of New Field Wildcats shows a particularly favorable trend, increasing each year from 1970 through 1977 when it reached a level of 45.5%, and an exceptionally good experience in any exploration province. Of particular interest is the experience for New Pool Wildcats, especially in the 1976 through 1978 period when the success ratio averaged over 60%. Again, these favorable ratios are influenced by natural gas discoveries in the shallow blanket sands and the Deep Basin areas.

Table 9

SUCCESS RATIOS - ALBERTA EXPLORATORY WELLS

(Percent of wells resulting in discoveries)

	<u>1970</u>	<u>1971</u>	<u>1972</u>	<u>1973</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977</u>	<u>1978</u>
New Field Wildcats	10.6	17.6	19.8	21.9	29.5	34.9	39.0	45.5	31.1
New Pool Wildcats	32.3	37.7	36.5	41.6	43.8	48.3	61.5	57.6	67.3
Deeper Pool Tests	16.7	24.4	21.1	27.3	31.5	24.7	48.0	44.4	36.3
All Exploratory Wells	25.2	31.6	29.3	33.7	37.0	40.9	53.9	51.7	51.0

Source: Canadian Petroleum Association Statistical Handbook

The power of discovery success can not be over rated as an incentive. Favorable geological prospects and results are critical. No amount of economic incentive will get the job done without attractive prospects.

Oil and Gas Reserves

As of a result of increased activity and favorable success ratios, initial reserves of oil and natural gas in the province have increased in the 1970's. Table 10 shows initial recoverable reserves of oil and gas and annual reserve additions for the years 1970 through 1978. While additions to oil reserves aggregated only a modest 7% over the period, additions to gas reserves showed a better than 50% increase. In fact the performance in natural gas has been so strong as to create a significant gas surplus in the province. Reserves of natural gas continue to be added even in the absence of near term markets. A declining trend of crude oil reserve additions may have been reversed with the discovery of West Pembina in 1977 and oil in the Deep Basin trend in 1978 and promising new finds in the Claresholm region of southern Alberta in 1979. It should be noted however that reserve additions have not offset withdrawals and thus remaining reserves are declining.

Impact of Geophysical Incentives

Figure 15 shows the reason for establishing the geophysical incentive program and the response to the program. Geophysical work activity had plunged to alarmingly low levels in the early 1970's and the response was

Table 10

ALBERTA OIL AND GAS

Initial Recoverable Reserves and Gross
Reserve Additions

	<u>Crude Oil (mmbbls)</u>		<u>Natural Gas (Bcf)</u>	
	<u>Initial Reserves</u>	<u>Gross Additions</u>	<u>Initial Reserves</u>	<u>Gross Additions</u>
1970	10,914	231	56,549	1,640
1971	11,053	139	58,161	1,612
1972	11,179	126	59,767	1,606
1973	11,237	58	66,276	6,509
1974	11,479	242	71,495	5,219
1975	11,523	44	72,234	739
1976	11,406	-117	75,981	3,747
1977	11,526	120	80,509	4,528
1978	11,680	154	86,305	5,796

Source: Alberta Energy Resources Conservation Board

Figure 15

the introduction of the geophysical incentive program on January 1, 1975. Figure 15 shows the portion of seismic activity that qualified for incentive credits since the introduction of the program. The number for 1979 is an estimate at this time. Initially the program was well received because the level of credit earned compared favorably with costs. Industry responded strongly and seismic activity took a sharp upturn with 90% of all activity qualifying for incentive credits in 1976 and 1977. Of interest is the fact that seismic activity continued its strong uptrend in 1978 in spite of the fact that the seismic incentive credits were cut in half and only some 35% of the seismic conducted was done under the incentive program. Geophysical activity turned down again in 1979 and it is estimated that only 25% of the activity was done under the incentive program.

The increase in activity in 1978 in spite of the lowered incentives relates to a burst of activity following the discovery of the West Pembina Field in 1977. This indicated that industry was willing to do seismic in areas where it was helpful in delineating good prospects with or without the presence of incentives. This raises a question often posed regarding the necessity for seismic credits. If the incentive to drill is strong enough and seismic will be helpful, any prudent operator will do the necessary seismic in any case.

The Chevron West Pembina Case

In the early months after the introduction of the geophysical program industry was slow to pick up on its application. Chevron was one of the first

of the major companies to recognize the implications of the program and they quickly moved to capitalize on it by putting 10 seismic crews in the field full time. As a company, Chevron had a competitive strength in seismic, had the crews and the people on hand and the expertise to capitalize on the program. Furthermore, the company was in a land short position in Canada and saw the advantages of a large seismic program which would built an information library that could be utilized to farm in to other operator's holdings. Perhaps the most important element of their program was the fact that the company was in a taxable position and as such could convert the tax-deductible expenses of seismic to cash through the reduction of their federal taxes plus earning the Alberta credits. This had the effect of permitting them to do twice as much seismic as was budgeted for without any budget impact or necessity to request financing for it. The company ran numerous seismic lines from the Alberta Saskatchewan border to the foothills using new techniques to look again at promising areas that may have been surveyed in the past. This was a natural strategy for Chevron because of their expertise, land position and tax position.

The direct result of Chevron's extensive seismic work in 1975 and 1976 led to the discovery of the WestPembina Field. Although the field may have been discovered anyway at some future date, the effect of the incentives was to advance the discovery of the field by some years.

Difficulties of the Program

While the Chevron experience spotlights the best of the incentive program, some of the contractor operators brought out the worst features of the program.

The biggest users of the geophysical incentive credits were the independent seismic contractors. These operators conducted seismic on speculation for resale or organized group shoots to do seismic for a number of operators together. Although group shoots provide cheaper access to information they seldom fit any one company's objectives. The seismic for resale proved quite profitable because after having a large portion of the cost covered by the incentive program, the information was often sold many times over. At its worst the incentive program gave rise to seismic activity that was undertaken for the sole purpose of recovering the incentive credits. There was a natural incentive to minimize the cost of the seismic and some very poor quality work was done. It was not possible for the government to check and monitor the quality control on all the seismic conducted without greatly increasing its staff, and this they did not want to do. Consequently some low quality work was done and frequently the least expensive areas in which to conduct seismic were surveyed many times over. Operators were literally lined up to shoot seismic along existing roads, forestry trails and other areas where there was no requirement to bulldoze or clean up. In some cases operators followed each other and used the same shot holes. These were the principal reasons that led to the reduction in the value of the geophysical incentive credits.

A feature of the program that bothered some of the operators, especially the majors, was the requirement that the information collected had to be released for public sale after three years. A number of companies did not

want to have to release data in instances where they may not have been able to put in place all the elements of an exploration play, including acquisition of the relevant lands, before the three year deadline date. In these cases the operators conducted their seismic outside of the program.

One of the pluses of the program was that it produced a large inventory of seismic information most of which became publicly available under the terms of the program. This was useful to the smaller companies in particular because they could buy just a few miles of a seismic line where they needed it whereas they would not undertake to conduct such a limited seismic program for themselves.

The geophysical incentive program is being phased down and is scheduled to expire on March 31, 1980, unless extended in some more modest form.

Impact of Royalty Exemptions

The existence of a royalty holiday on production from a discovery well is not so much of an incentive as it is a bonus. The prospect of a royalty free period of production significantly enhances the prospective rate of return on a project that would qualify.

From its introduction in 1972 until 1977, the royalty holiday on crude oil was not a significant factor because there had not been much new oil discovered. With the discovery of the West Pembina Reef Fields in 1977 the oil royalty exemption took on more significance. The West Pembina Fields were ideally suited for such credit from the point of view of the operators but badly configured from the viewpoint of the Alberta

Government. As initially contemplated in the promulgation of the regulations, the initial discovery well in a field would receive the royalty exemption. This would theoretically lead to additional wells being drilled on which the government would collect its full royalties. In the case of West Pembina however, the majority of the fields proved to be pinnacle reefs which could be essentially drained by one single well, each one of which qualified as a new field discovery for purposes of receiving the royalty exemption. This produced fabulous rates of return for the operators, and no royalty revenues for the province. Moreover, these fields can have a flush production period for the first several years after which production can be expected to decline. Government royalty collections only commence after five years of production or after production has already declined and much of the field's reserves have already been produced. On the other hand, it can be argued that the purpose of the program was to incentivize more oil discoveries, and this it accomplished.

In the case of natural gas the two year royalty holiday introduced in 1974 was reduced to one year in 1978. This reflected the fact that substantial discoveries of gas had been made and in fact a natural gas surplus had been created. It was therefore acceptable to withdraw a portion of the incentive to find additional gas for which there were no near term market prospects. In the absence of near term markets for gas the value of the royalty holiday had little present value impact for the operators in any case.

Administration of Incentives Programs

The Alberta incentive programs are administered by the Alberta Energy and Natural Resources Department and the Alberta Energy Resources Conservation Board. The programs are administered by relatively small staffs with modest budgets.

The EDICP program is administered jointly by the Department of Energy and Natural Resources (ENR) and the Energy Resources Conservation Board (ERCB). The ERCB provides the certification of a well as an incentive exploratory well and determines the qualifying footage. The ERCB maintains one of the oil industry's best kept information systems on each and every well that has ever been drilled in the province of Alberta. Access to this most complete and high quality information makes it possible for the ERCB to classify and qualify wells. The ERCB staff consists of a geological supervisor, a geologist, a technician, a senior clerk and two or three assistants. The ERCB budget for these activities has grown from about \$50,000 annually in 1973 to somewhat over \$125,000 per year in the latter 1970's.

Determination of the credit to be established is made by ENR. They are also responsible for allocating the credits and accounting for their status and utilization.

ENR also handles the complete administration of the geophysical incentive program. They are responsible for certifying geophysical programs, seismic quality control, and the allocation and utilization of seismic credits. There are a number of ENR staff members involved to some degree

in the incentive programs. The seismic program requires two full time senior administrators plus the use of personnel from accounting. Overall the incentive programs may account for the use of four full time staff people plus the use of a half-dozen senior staff people for part of their time. ENR administrative costs assigned to the incentive programs has increased from approximately \$20,000 in 1973 to over \$75,000 per year in the latter 1970's.

The total government costs of incentive program administration has increased from approximately \$70,000 in 1973 to somewhat over \$200,000 a year by the latter 1970's. Administrative costs are a minor factor in the programs.

Incentive Program Costs and Benefits

Cost of Incentive Programs

The costs to the Alberta government of the various incentive programs has escalated sharply since their inception in 1972. Table 11 shows the annual costs of each of the various incentive programs.

The amount of exploratory drilling credit has increased each year in line with an increase in qualifying wells and footage drilled each year under the program. The increasing costs also reflect a progressive enrichment of the incentives.

The cost of the royalty exemptions provision was quite modest for the first five years of its existence. This was because very little new oil was being discovered in those years to qualify for the royalty exemption

Table 11

AMOUNT OF ALBERTA INCENTIVE CREDITS

(\$ millions)

	<u>Exploratory Drilling Credits</u>	<u>Royalty Exemptions</u>	<u>Geophysical Credits</u>	<u>Totals All Credits</u>
1973	\$ 12.7	\$ 0.04	-	\$ 12.7
1974	16.8	0.3	-	17.1
1975	27.1	0.7	5.4	33.2
1976	43.8	2.0	13.5	59.3
1977	60.0	6.3	21.9	88.2
1978	71.0	20.0	23.4	114.4
	<hr/>	<hr/>	<hr/>	<hr/>
Cumulative Amounts 1973-78	\$231.4	\$29.3	\$64.2	\$324.9

Source: Alberta Energy and Natural Resources.

Alberta Energy Resources Conservation Board.

and although natural gas was being discovered, not that much of the newly discovered gas was being brought to market. This all changed sharply in 1977 with a number of new discoveries being made in the West Pembina area. The sharp increase for 1978 reflects the West Pembina discoveries. The amount of royalty credits for 1978 were more than two times the cumulative amount of credits for the prior five years. The West Pembina wells are high productivity wells and in the fall of 1978 Chevron had eight wells producing in that area of which six were incentive wells that qualified for the royalty holiday. Under federal tax laws these unpaid royalties were not included in Chevron's production income yet Chevron still received the 25% federal Resource Allowance as if the royalties were paid.

The value of geophysical credits has increased to a level of over \$20 million per year but are expected to show a sharp decline beginning in 1979. The fact that the 1978 amount of geophysical credits shows a higher value than 1978 in spite of the fact that the value of the incentive credits were cut in half and a lower portion of seismic activity qualified for the incentives relates to the manner in which Energy and Natural Resources compiles the data. ENR data represents credit transactions certified during the year and these do not entirely pertain to the timing of when the seismic activity is conducted. Undoubtedly some of the credit certified in 1978 applies to programs actually conducted in 1977.

Benefits to Industry

Although the amount of incentive credits has gone up sharply since the programs were first introduced in 1972, oil industry expenditures in Alberta have also increased sharply. This is particularly true of exploratory spending which showed a fivefold increase from 1973 to 1978. In order to evaluate the impact of the incentive programs it is of interest to examine the amount of incentives compared to industry spending levels.

Table 12 shows industry expenditure levels on exploration in Alberta as compared to the value of the credits earned from the exploratory drilling incentive program. The table shows that the value of the EDICP credits accounted for about 15% of expenditures on exploratory drilling on average for the 1975 through 1978 period. This is a significant contribution to underwriting the cost of exploratory drilling. Exploratory drilling does not go on without expenditures on geological, geophysical and land acquisition activities and perhaps it is more relevant to view the credits as a part of these broader activities. Even in this light, the EDICP credits were significant in relation to total expenditure, amounting to about 10% of drilling plus geology and geophysical expenditures on average for the 1975-1978 years, and about 5.3% of total exploratory expenditures on average for the same period.

Table 13 relates credits for each of the incentive programs to directly related expenditures and to total industry expenditures over all. Geophysical credits financed an average of 7.8% of expenditures on geology and geophysics during the 1975-1978 period. As noted, EDICP credits financed 15% of drilling expenditures during the

Table 12

ALBERTA EXPLORATORY EXPENDITURES AND DRILLING INCENTIVE CREDITS

	<u>1973</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977</u>	<u>1978</u>
<u>EXPENDITURES (\$mm)</u>						
Exploratory Drilling	\$131.4	\$146.5	\$149.1	\$256.5	\$394.7	\$644.5
Drilling & Geol. & Geoph.	202.1	288.9	248.1	402.0	518.1	994.8
Total Exploratory	346.4	416.2	456.0	657.5	1298.0	1735.3
 <u>TOTAL EXPL. DRLG.CREDITS</u>	 12.7	 16.8	 27.1	 43.8	 60.0	 71.0
 <u>CREDITS % OF EXPEND. (%)</u>						
Exploratory Drilling	9.7	11.5	18.2	17.10	15.2	11.0
Drilling & G & G	6.3	5.8	10.9	10.9	11.6	7.5
Total Exploratory	3.7	4.0	5.9	6.7	4.6	4.1

Source: Canadian Petroleum Association, Statistical Handbook
 Alberta Energy and Natural Resources
 Alberta Energy Resources Conservation Board

Table 13

PETROLEUM INDUSTRY EXPENDITURES IN ALBERTAAND AMOUNT OF INCENTIVE CREDITS EARNED

(\$ mm)

	<u>1973</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977</u>	<u>1978</u>
<u>EXPENDITURES</u>						
Geology & Geophysics	70.7	112.4	99.0	145.5	223.4	350.3
Drilling	131.4	146.5	149.1	256.5	394.7	644.5
Land Acq. & Rental	<u>144.3</u>	<u>157.3</u>	<u>207.9</u>	<u>255.5</u>	<u>679.9</u>	<u>740.5</u>
Total Exploration	346.4	416.2	456.0	657.5	1298.0	1735.3
Development	350.7	455.4	562.0	845.6	861.2	1129.2
Operating	388.5	488.4	640.2	826.4	910.9	1039.4
Royalties*	422.6	1107.2	1477.7	1974.1	2398.9	3054.9
	<hr/>	<hr/>	<hr/>	<hr/>	<hr/>	<hr/>
TOTAL EXPENDITURES	1508.2	2467.2	3135.9	4303.6	5469.0	6958.8
<u>CREDITS</u>						
Geophysical	0.0	0.0	5.4	13.5	21.9	23.4
Expl. Drilling	12.7	16.8	27.1	43.8	60.0	71.0
Royalty Exemption	<u>0.04</u>	<u>0.3</u>	<u>0.7</u>	<u>2.0</u>	<u>6.3</u>	<u>20.0</u>
TOTAL CREDITS	12.7	17.1	33.2	59.3	88.2	114.4
<u>CREDITS AS % OF EXPENDITURES</u>						
Geophysical % of G&G Expend.	-	-	5.4	9.3	9.8	6.7
Expl. Drlg % of Drlg Expend.	9.7	11.5	18.2	17.1	15.2	11.0
Royalty Exempt.% of Royalty Pd.	0.0	0.0	0.0	0.1	0.3	0.7
TOTAL CREDITS % OF TOTAL EXPEND.	0.8	0.7	1.1	1.4	1.6	1.6

*Net of incentive credits where applicable

Source: Canadian Petroleum Association, Statistical Handbook
 Alberta Energy and Natural Resources
 Alberta Energy Resources Conservation Board

1975-1978 period. The value of royalty exemptions are an insignificant part of the total royalties paid. For this period total credits earned amounted to less than 1-1/2% of total industry expenditures in the province.

Table 12 and 13 demonstrate one feature of the effectiveness of the incentive programs. Although the incentive credit amounts are a minor portion of total industry expenditures, they are a meaningful part of the specific activity they were meant to stimulate, namely exploratory drilling.

Benefits to Alberta

From the point of view of the Alberta government, the incentive programs have been highly successful. The programs were an important factor in reviving exploratory activity in Alberta. Once increased activity was achieved, the pull of a highly successful discovery rate sustained and increased the industry's exploration momentum.

The contribution of the increased oil and gas industry activities to the revenues of the province of Alberta and its salubrious economy are impressive. Figure 16 shows oil industry cash expenditures on exploration in Alberta for the decade 1968 to 1978. Table 14 shows revenues to the Alberta government from the sale of Crown oil and gas rights and from royalties on conventional production. Including provincial taxes from oil and gas we estimate that Alberta's revenue from the oil and gas industry increased sevenfold over the five year period 1973 to 1978, from \$500 million to \$3.5 billion. The greatest portion of the increase comes

INDUSTRY NET CASH EXPENDITURES ON EXPLORATION - ALBERTA

FIGURE 16

Source: Cdn Petr.
Assoc.

from higher royalty rates which represents the province's share of the economic rent attaching to higher oil and gas prices.

In percentage terms, the magnitude of the increase in revenue from lease sales has been the most impressive, rising from \$76.6 million in 1973 to nearly \$1 billion in 1979. The fact that exploratory credits earned could be applied against the bonus payment on Crown land purchases has often been cited as a factor contributing to the escalating price of leases in Alberta. This has probably been a factor of significance in the case of particular companies who did not have other means of earning back the incentive credits. Data compiled for 1978 indicates that some 8.7% of the credits earned by industry were applied towards the purchase of lease bonuses. This amounted to only 1.6% of the value of all lease purchases for the year. Estimated data for 1979 lease sales indicates that only 1.2% of lease bonus payments were in the form of incentive credits. Overall, therefore, it does not appear that the credits have been a principal factor behind rising lease bonus prices. It should be kept in mind, however, that whether credits are taken against royalties or lease bonuses they are all a part of the producer's cash flow picture.

The EDICP program was particularly favorable for stimulating economic activity within the oil industry, especially the drilling sector. With the average exploratory well earning a credit of 35%, this meant that each \$0.35 of expenditure generated \$1.00 of economic activity, plus its multiplier effect.

Table 14

ALBERTA GOVERNMENT REVENUES
FROM
OIL AND GAS LEASES, ROYALTIES AND RENTALS
(\$ millions)

<u>Year Ending</u> <u>12/31</u>	<u>Sales of Crown</u> <u>Oil & Gas Rights</u>	<u>Year Ending</u> <u>3/31</u>	<u>Conventional Oil & Gas</u> <u>Royalties & Rentals</u>
1972	\$ 57.7	1973	\$ 262.5
1973	76.6	1974	423.5
1974	84.7	1975	1,240.3
1975	120.6	1976	1,547.2
1976	160.2	1977	1,873.8
1977	595.7	1978	2,368.8
1978	603.2	1979	2,883.1
1979 est.	996.7		

Source: Alberta Energy and Natural Resources

Note: Lease sale data is available on a calendar year basis but E & NR revenue data is reported in E & NR Annual Reports for years ending March 31st only.

The amount of the incentive programs has been a minor part of total petroleum and natural gas revenues to the Province. The value of incentives as a percentage of Crown revenues from oil and gas is **estimated** as:

	<u>1973</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977</u>	<u>1978</u>
Incentives as % of P&NG Revenues	2.5	1.3	2.0	2.9	3.0	3.3

The health of the oil industry has fueled Alberta's economic progress. Between 1972 and 1978 the gross domestic product (GDP) of Alberta, measured in current terms, grew at a compound rate of almost 22% to in excess of \$23 billion in 1978. As a result of this relatively rapid growth, the Alberta GDP rose from 8% of the Canadian total in 1972 to 12% in 1978, and economic performance remains strong. The impetus for the remarkable economic expansion which Alberta has experienced over the past few years has been a high level of investment, a major focus of which has been in the petroleum industry. Today roughly 25% of Alberta's output is directly related to production of fossil fuel resources.

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VIII FRONTIER EXPLORATION ALLOWANCES

Description

The Frontier Exploration Allowance essentially consists of a single tax provision called "Super-Depletion" which permits additional amounts of depletion, beyond normal depletion, to be earned on high cost Frontier oil and gas exploration wells. Appendix D describes the Frontier Exploration Allowance provisions in the Canadian income tax code.

The super-depletion provision allows a third type of earned depletion to be accumulated at the rate of 66-2/3% of eligible expenditures. These eligible expenditures are exploratory oil and gas wells costing at least \$5 million. Only expenditures in excess of \$5 million generate super-depletion credits. This would typically mean a well in Canada's frontier and offshore regions. Super-depletion is in addition to the usually earned depletion of 33-1/3%, and the 100% writeoff for exploration costs. This additional depletion may be deducted fully against any income rather than being limited to 25% of resource income. This provision results in a permanent reduction in tax liabilities. In conjunction with the fast write-off on Canadian exploration expenses (fully deductible) and 33-1/3% earned depletion, this provision implies that up to 200% of these frontier exploration costs can be deducted immediately.

Operation

An example of how the super-depletion provision operates is presented in the tabulation that follows. The example would be for a well drilled in the offshore frontier regions of Canada such as in the Beaufort Sea or offshore the East Coast of Canada costing \$40 million. The example assumes that the well is drilled by an Alberta company with resource income that is currently paying taxes and that the company has sufficient income to fully and immediately utilize Canadian exploration expense.

Drilling Cost		\$40,000,000
Exploration Expense (100% deductible)	\$40,000,000	
Earned Depletion (33-1/3% of \$40mm)	13,333,333	
Frontier Allowance (66-2/3% of \$40mm - \$5mm)	<u>23,333,333</u>	
Total Expense for Tax Purposes	\$76,666,666	
Tax Saving at 47% Rate		<u>(36,033,333)</u>
Well Cost After Tax		\$ 3,966,667
After Tax Cost per Dollar Risked		9.9¢

The after-tax cost of approximately 10¢ per dollar invested for super-depletion wells can be compared with an after-tax cost of 37¢ per dollar invested for exploratory wells drilled in Alberta (see Table 4).

While the above level of incentive was quite attractive, there was a means available to further enhance it. The enhancement concept was particularly attractive for companies who had a low corporate tax rate. The mechanism to enrich the incentive was to pass through the super-depletion tax benefits to high tax bracket individuals who would finance

the exploration activity in return for a nominal interest in the wells. Under a temporary provision of Canadian tax law, individuals could write off exploration expenses against any income up to 100% in one year. Furthermore, the frontier allowance could also be fully written off against any income. The individual investor could not, however, qualify for the earned depletion credit as that could only be written off against other resource income. If an individual had resource income he could of course also get credit for earned depletion. The tax effect of super-depletion at higher tax brackets (excluding any earned depletion credit) is shown below.

Well Cost				\$40,000,000
Exploration Expense		\$40,000,000		
Frontier Allowance		<u>23,333,333</u>		
Total Expense for Taxes		\$63,333,333		
Tax Rate (%)	50%	60%	63%	68%
Tax Saving (\$mm)	31.7	38.0	40.0	43.1
Well Cost After Tax (\$mm)	8.3	2.0	0	(3.1)
After Tax Cost per \$ Risked (¢/\$)	21	5	0	(7.7)

For a taxpayer in the highest bracket it is possible to receive tax benefits in excess of his investment. The top marginal tax rate for combined federal and Provincial taxes in Canada is 67.9% (excluding Provincial surtaxes) except for Quebec where the top rate is 68.9%.

Impact.

The Frontier Exploration Allowance was introduced in March of 1977 and expired as scheduled on March 31, 1980. There is no doubt that

super-depletion was a powerful incentive and this relatively short time-frame brought about a burst of activity very quickly. While the incentive was strong, and clearly instrumental in promoting the activity, there were not many candidates to take advantage of it. There were a limited number of players who were willing to risk even the after-tax cost of frontier exploration. The principal reason for this reluctance was in the present value of expenditure where any economic return was many years away, perhaps even more than a decade. It would take large-scale success and enormous follow-up expenditures before any return would be realized, and with the near-term attractiveness of places like Alberta, there was not a stampede of entrants into the frontiers. Furthermore, most of the frontier exploratory acreage was held by a relatively small number of companies, essentially the larger majors. The most notable exception was Dome Petroleum which held a very large position in the Beaufort Sea area and Dome was the first and most aggressive company to capitalize on the super-depletion concept. The company spearheaded a major program of activity in the Beaufort Sea offshore which appears to have culminated in the discovery of some potentially major oil and gas deposits. One of the objectives of the Canadian Federal Government was to survey the potential of its frontier regions, and this appears to be resulting.

The other area of major frontier activity is off the eastern coast of Canada, off Newfoundland and Labrador. These areas have been operated mainly by the international major companies. Offshore Newfoundland, in particular, appears to be yielding discoveries of major significance to the

national oil supply picture of Canada, and perhaps even of North American significance.

Super-depletion is a classic incentive in the sense that something of that nature was absolutely required to get the work done at the time and its existence has promoted the activity which fortuitously appears to be yielding the desired results, perhaps even beyond the planners' expectations.

There are, however, negative aspects to the frontier allowance program. Because of the richness of the program which permits the writeoff of 200% of exploratory expenses above \$5 million, there is little incentive to minimize costs or maximize efficiency of expenditures. It should be pointed out, however, that the hostility of the environment and the shortness of the season in the Canadian frontier areas are factors not conducive to cutting costs.

A further negative is the fact that certain high tax bracket individuals can actually make money by investing with super-depletion credits. The pass-through of tax benefits to individuals was a situation not foreseen in the original design of super-depletion. On the plus side this feature has attracted new funds into the frontier exploration effort. A negative aspect to the program from a Canadian nationalist point of view is the fact that the program is mostly benefiting large, foreign-owned or foreign-controlled companies. The fact that the form of the program is a tax writeoff means that the larger companies, with larger incomes and profits, are reaping the largest benefits. In addition, most of the federal lands where qualifying

costly wells could be drilled are held by these foreign-controlled companies.

The cost of the program to the federal government was estimated at \$100 million for 1979. Of this, \$70 million was estimated as credits on corporate income tax, and \$30 million as credits against personal income tax.

The super-depletion program expired as scheduled on March 31, 1980. At the end of 1979 the Conservative government proposed reducing the super-depletion credit from 66-2/3% to 6-2/3% but the government was defeated before this was enacted. It is generally believed that some form of frontier exploration incentive will be initiated after the present program expires.

IX. TAR SANDS AND HEAVY OIL INCENTIVES

There are basically three types of heavy oil production in Canada. There is the Lloydminster type of heavy oil of 12 to 16 degree gravity which will flow naturally and is recoverable by conventional means. The Cold Lake deposits are about 10 degree gravity and are not recoverable without steam treatment. The tar sands, or oil sands, contain 8 degree gravity or lower oil which is only recoverable by mining. The oil recovered from the tar sand and Cold Lakes deposits require upgrading before being processed like conventional crudes.

The principal incentive for heavy oil recovery in Alberta operate through the federal tax system and through a program of diminished provincial royalty collection. Special features such as the provision for world price and government financial participation are individually negotiated matters on a project-by-project basis.

Oil Sand Incentives

The specific financial, tax and royalty arrangements for each oil sands plant in Alberta are individually negotiated for each project and therefore no standard arrangement exists. There are, however, a number of features in the federal tax code that universally apply to these investments. Among the most important of these is the 100% deductibility of all development expenditures which include not only all construction costs but includes social infrastructure investment as well.

Another significant feature is an additional earned depletion for heavy oil and tertiary recovery projects. This permits the purchase of machinery and equipment to earn depletion at a rate of 50% which is in addition to the deductibility of one-third of the cost of property acquired for mining the tar sands which is the normal earned depletion amount. Moreover, this type of earned depletion may be deducted up to one-half of resource income rather than the usual limitation of 25%. Any unused supplementary depletion is carried forward for use in future years. This provision results in an additional 50% writeoff of certain costs and thus results in a permanent reduction rather than deferral of tax liabilities.

A further special provision is embodied in the terms of the Syncrude oil sands project. The regular tax system provides a resource allowance of 25% of resource profits in lieu of the deductibility of provincial taxes and royalties. The Syncrude project, however, is permitted to deduct both the resource allowance and provincial royalties in computing income subject to tax.

All projects would, of course, be subject to accelerated depreciation and investment tax credit provisions of the normal tax code.

Beyond the provisions of the federal tax code the remaining elements are matters of negotiation. The operating or planned projects either receive or hope to receive world price for the product both because this price is economically attractive and because this price is set independent of Canadian political factors. The projects typically receive guaranteed

markets for their full output. The Alberta government participated financially in the Syncrude plant with both equity and convertible debenture financing.

One of the principal areas of negotiation with the Province is the determination of the Provincial royalty level. The Syncrude project received a royalty holiday on the first 5 million barrels of production and a favorable rate thereafter. The proposed Alsands project is discussing a 2% gross royalty increasing by 2% every 18 months until a maximum of 10% is reached, and then holding at that level until payout. After payout the royalty would increase to 35% of net.

Oil sands plants must be very large to be justified economically and consequently they are massive investments of many billions of dollars each. Availability of substantial tax credits results in a major reduction of cash impairment to the investor and a greatly reduced risk to capital going in. The effective cash outlay during construction is reduced because a fully taxable company is able to deduct the costs of such a project against current income from other operations.

Heavy Oil Incentives

Production from the Cold Lake area receives the normal tax treatment plus the supplementary depletion credit of 50% for heavy oil and enhanced recovery projects. The province of Alberta views production from the Cold Lake area as experimental at this time and has only licensed pilot plant projects. For such experimental projects the provincial royalty rate is

set at 5%. Imperial Oil is contemplating the construction of an upgrading plant at Cold Lake which might cost as much as \$7 billion. Such a plant would hope to get incentives similar to the tar sands plants. The Lloyd Minister type production gets the normal federal tax treatment plus it is also eligible for the supplementary 50% depletion for heavy oil projects. Since the Lloyd Minister wells are low productivity wells they subject to a reduced royalty rate of about 18 to 20%, or even lower on new oil.

There are no particular incentives to stimulate production from tight sand deposits in Alberta. However, Alberta royalties vary with productivity and decrease at the lower productivity levels providing an automatic incentive.

IX BRITISH COLUMBIA: A COMPARISON

Differences: Alberta and British Columbia

The oil industry is much less important in British Columbia than it is in Alberta. In Alberta the economic base of the province is intricately tied to oil and gas. In British Columbia oil and gas ranks behind forestry, mining and fisheries. Oil and gas activity extends virtually throughout the whole province of Alberta while in British Columbia no more than 25% of the province is suitable for oil and gas exploration. The number of oil and gas wells drilled in British Columbia range between 200 and 400 wells per year in the 1976 to 1978 period whereas in Alberta the comparable numbers were in the 5000 to 5600 per year range. British Columbia is essentially a gas prone area where prospects tend to be somewhat deeper on average than in Alberta and costs run higher than in Alberta.

Since late 1973 all natural gas produced in British Columbia has been sold to a Crown corporation, the British Columbia Petroleum Corporation. The Corporation purchases gas at a price net of royalty and gathering charges so the price is not directly comparable to the Alberta price, however, the net back to the producer has on average been somewhat lower than in Alberta.

B.C. Oil and Gas Activity

Table 15 traces the development of selected measures of oil industry activity in B.C. through the 1970's. The activity levels for the early

Table 15

OIL AND GAS ACTIVITY - BRITISH COLUMBIA

	<u>1970</u>	<u>1971</u>	<u>1972</u>	<u>1973</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977</u>	<u>1978</u>
TOTAL WELLS DRILLED	172	186	217	173	142	80	187	332	402
GEOPHYSICAL CREW WEEKS WORKED	162	223	225	240	210	41	152	369	378
BONUS PAYMENTS (\$ mm)	16.3	22.2	20.5	17.8	23.0	12.7	43.2	125.5	177.5

Source: B.C. Energy, Mines and Petroleum Resources, Oil & Gas Statistics.

years of the 1970's could be described as normal. Activity turned down in 1974 with the onset of the federal provincial pricing conflicts and activity collapsed in 1975. The 1975 situation reflected more than just the federal provincial revenue conflicts. At that time the B.C. Petroleum Corporation was the sole purchaser of natural gas in the province and although they had increased natural gas prices to the producer in 1974 they had also frozen producer prices on a long term basis by announcing in January of 1975 that there would be no flow back to producers in British Columbia of any higher prices obtained for gas in export. However unfavorable the 1975 net back to the producer in Alberta might have been, the Alberta producer had the comfort of knowing that if gas prices went up in Toronto the producer would immediately get some form of increase automatically. A British Columbia producer was faced with the prospect of little or no improvement in his administered net back price at a time of rapid inflation in exploration and development costs. The industry abandoned British Columbia and exploration activity nearly halted.

Towards the end of 1975 the government made price and royalty adjustments which improved the producer's position sufficiently to restore exploratory activity. Drilling picked up in 1976 and was at record levels in 1977 and 1978. The latter two year's activity reflects interest in the Deep Basin play which extends into B.C. from discoveries originally made in Alberta.

It is productive to examine some estimated net backs to the producer for oil and gas in both British Columbia and Alberta over the period under review. The net backs are an apparent proxy for the level of industry activity.

Producer Net Backs - B.C. and Alberta

	Crude Oil (\$/bbl)		Natural Gas (¢/mcf)	
	<u>Old</u>	<u>New</u>	<u>Old</u>	<u>New</u>
1974-mid 1975				
Alberta	1.43	2.07	16.0	19.4
B.C.	.03	.03	8.3	14.7
late 1975				
Alberta	2.09	2.83	25.0	32.9
B.C.	1.41	1.91	16.4	26.3
1978				
Alberta	2.53	3.68	33.0	47.0
B.C.	2.40	3.25	18.0	40.0

B.C. Incentive Program

As a part of its industry resurrection program in 1975 B.C. introduced an incentive credit program in November of 1975. A credit was established of 75¢ for each barrel of oil produced and 15¢ for each mcf of gas produced in the province. The credit could only be earned by making qualifying exploratory expenditures and it was earnable at the rate of 75¢ for every dollar expended. This led to a system of producers filing affidavits and claims to be reviewed by the government who then sent out cash rebates. The program proved an administrative burden and it was abandoned on November 1, 1977 for gas and January 1, 1978 for oil. The government

realized that the incentive program was merely a method of supplementing producer net back. They withdrew the program and incorporated its benefits into a basic improvement in producer net back.

One form of incentive that has been available to B.C. producers and not to Alberta explorers is the fact that the B.C. Petroleum Corporation purchases gas on a deliverability basis and thus provides some degree of readily available market for all new gas discoveries.

Success Ratios

It has previously been suggested that one of the reasons for the high degree of exploratory activity in Alberta is that it has been sustained by an exceptionally favorable discovery rate. Table 16 presents the success ratio experience for exploratory and development wells in British Columbia for the 1970's. The success ratio in both exploratory and development categories is significantly below the experience in Alberta. Although British Columbia has not proven to be as favorable an exploration province as Alberta the discovery rate in the late 1970's has been encouraging, highlighted by discoveries in the Deep Basin trend in 1977. It should be kept in mind that the British Columbia discoveries are mostly natural gas which is less attractive economically than oil.

Table 16

SUCCESS RATIOS - BRITISH COLUMBIA EXPLORATORYAND DEVELOPMENT WELLS

	<u>1970</u>	<u>1971</u>	<u>1972</u>	<u>1973</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977</u>	<u>1978</u>
<u>EXPLORATORY WILDCATS</u>									
No. of Wells	52	45	56	55	45	21	39	62	64
Success Ratio (%)	15	18	30	35	38	33	36	66	47
<u>EXPLORATORY OUTPOSTS</u>									
No. of Wells	45	58	77	50	40	27	48	90	147
Success Ratio (%)	36	24	36	26	20	33	69	52	66
<u>DEVELOPMENT WELLS</u>									
No. of Wells	75	83	84	68	57	32	100	180	191
Success Ratio (%)	75	65	71	57	51	56	69	71	76
<u>TOTAL WELLS</u>									
No. of Wells	172	186	217	173	142	80	187	332	402
Success Ratio (%)	47	41	48	41	38	42	62	65	68

Source: B. C. Energy, Mines and Petroleum Resources, Oil & Gas Statistics.

XI APPLICABILITY TO U.S. POLICY

The Alberta Exploratory Incentive Credit Programs were developed in response to a series of specific needs. Initially they were instituted to redirect exploration spending back to the province and to provide a partial offset to higher royalty rates. Exploratory activity in the province was declining both in absolute terms and in Alberta's share of the total Canadian activity. As a result, funds were being withdrawn from the province to finance exploration elsewhere. After the programs were established they were enhanced to provide encouragement for the industry after high royalty and tax policies had proved regressive. The enrichment and broadening of incentives were also means by which the Alberta Government sought to restore its credibility with the oil industry following the federal-provincial revenue disputes.

The situation in the U.S. today bears little resemblance to the background leading up to the special incentive programs in Canada. While it was not within the scope of this study to specifically assess the level of exploration in the U.S., it is clear that oil and gas exploration activity is at very high, even record, levels. In fact, exploratory spending in the U.S. may be so high as to be bidding up the price of land and services to the oil industry. In this environment the introduction of further blanket-type drilling incentives would appear to be unnecessary.

As is illustrated by the Canadian case, the prime motivator of exploratory activity is the expected net back to the producer and his near term cash flow picture. Essentially the Canadian special incentive

programs were designed to improve net back and supplement producer cash flow. The U.S. has already put in place two programs which offer a producer the prospect of improving net backs on production. These programs are the Energy Conservation and Production Act (1976) and the Crude Oil Decontrol program which permit higher prices for gas and oil respectively. Even with the implementation of the Windfall Profits Tax producer net backs and cash flow positions can prospectively improve.

Even within the frontier exploration areas of the U.S., industry appears willing, even eager, to pursue exploration. This is indicated by the general level of bidding interest at such frontier sales as the Alaskan Beaufort Sea sale. The inability to pursue a higher level of exploratory activity would appear to be more closely linked with the frequency of federal lease sales and the difficulties and time required in securing environmental permits to proceed. While industry may be willing to accept the risk of exploration, even in high cost and frontier areas, there is a reluctance to take on the risk of indeterminate delay associated with permitting of operations. Any procedure that would define or limit this risk would in itself be a meaningful incentive to activity.

Alberta Compared to the U.S.

Alberta is perhaps uniquely suited for the development and administration of an exploratory drilling credit program. Alberta is essentially one geologic province, lying entirely within the Western Canadian Sedimentary Basin. Although costs did differ in different geographic parts of the Province there was sufficient uniformity of conditions throughout the Basin to permit the development of blanket incentives.

The Government of Alberta owns more than 80% of all the oil, gas and mineral rights in the Province. This ownership provides them with complete

authority over the disposition and administration of such rights and authority over such factors as the royalty rate. Control over these factors permits the government to adjust the supply of land available and the profitability of production. Government control of lease bonuses and royalties also provides a mechanism by which earned incentives can be monetized.*

A further important feature in administering the Alberta programs is the existence of an exceptional industry information base within the Energy Resources Conservation Board. The Board maintains a complete library of information on each and every well drilled within the province of Alberta and access to this information permits the timely review and classification of proposed incentive wells.

By contrast, the situation in the U.S. offers few of the positive aspects of the Alberta situation from which to draw. Establishing a blanket incentive program such as the EDICP program would be unadvisable in the U.S. where there is a complete spectrum of totally different geologic basins, each with unique characteristics. What may prove to be an overly generous incentive in one area may be completely inadequate to encourage activity in another area. While blanket exploratory drilling incentives directed towards wildcat wells may be thought to be desirable it is likely they would prove to be exceedingly difficult to design in a manner that would be equitable and not subject to some abuses. The lesson of the Alberta geophysical program is instructive. The program could not be adequately supervised without a large staff of technicians which would have to come

* In addition, provincial control of mineral rights permitted coordination of leasehold regulations with other incentive programs, and/or regulatory changes which by themselves acted as incentives to exploration activity. While it was beyond the scope of this study to review changes in land regulations, it is probable that changes in leasehold terms played a role in causing certain exploratory activity to take place.

from the activity that was trying to be stimulated. It is also significant that even though the geophysical incentive program has not been satisfactory and the government would like to withdraw it, this is not as easy to do as it was to initiate the program. The government undertook a phase down of the program rather than its abrupt withdrawal. Once incentive programs become established, their economics become a part of the cost structure and they typically prove difficult to withdraw from.

The U.S. has one major advantage over the Canadian situation and that lies in the broad jurisdiction of the federal government to control the fiscal parameters of the oil and gas industry. The States in the U.S. do not have the ownership and authority over natural resources as the Provinces do in Canada. Therefore, it should be possible to minimize the largely negative federal-provincial revenue sharing type of conflicts that developed in Canada.

Although a blanket incentive program to encourage exploratory drilling may not be advisable in the U.S., limited, focused incentives could be productive and merit further investigation. Incentives to exploration may be appropriate, or even required, in areas which appear to have potential but which industry is not now exploiting. Specifically, incentives might act to advance the timing of exploration in certain especially high risk, remote or high cost areas. Such incentives should be limited, 'rifle-shot' incentives directed at specific areas or geologic horizons of potential. Having already put in place a crude oil and natural gas decontrol program in combination with a windfall profits tax on production, the mechanism for incentivising particular areas of activity or types of production is in place. This might be done either through decontrolling certain types of production or by exempting it from the windfall profits tax.

APPENDIX A

SIGNIFICANT CANADIAN INCENTIVE, TAX

AND ROYALTY CHANGES IN THE 1970S

Date of Change

1971	Federal government terminates automatic depletion allowance of one-third of taxable income to be replaced by an earned depletion of a \$1.00 deduction from taxable income for each \$3.00 spent on exploration or development.
August, 1972	Alberta introduces the Exploratory Drilling Incentive System. The program covers all wells classified as New Field Wildcats. Approximately 30% of the cost of the well could be established as a credit. The total footage of the well was eligible. A 5-year royalty holiday was granted on oil production from these wells.
January, 1973	Alberta revised its royalty schedule increasing the maximum rate to 25% from 16-2/3% on crude oil production from most Crown leases. An approximately equal reserves tax was instituted to apply where a lessee chooses not to amend its lease to permit the higher royalty.
April, 1973	Saskatchewan revised its royalty schedule increasing the maximum oil royalty for Crown leases to 25% from 16%.
June, 1973	British Columbia revised its royalty schedule increasing the maximum oil royalty to 40% from 16-2/3%.
September, 1973	Producers agreed to a voluntary crude price freeze until the end of January, 1974.
October, 1973	Federal Government introduced the Crude Oil Export Tax.
November, 1973	With the negotiated takeover of contracts from Westcoast Transmission Company, the British Columbia Petroleum Corporation (BCPC) began to purchase natural gas from producers on a royalty-free basis, but at lower than market prices. The difference between the market price and the price paid producers effectively became a hidden or deemed provincial royalty. This was at higher than previous rates.
	A higher field price was announced for gas contracted to the British Columbia Petroleum Corporation after November 1973 (new gas).

APPENDIX A (continued)

January, 1974

Alberta established a mineral tax on freehold oil and gas production at a level which brought the total provincial levy into line with the royalty on Crown lands.

Alberta increased its drilling incentive credits which were established in August, 1972. The credits for keep wells more than doubled with the maximum credit increasing to \$1.16 MM for an 18000 foot foothills test.

Saskatchewan imposed a royalty surcharge on Crown oil production and a mineral income tax on freehold production which effectively charged a 100% royalty on the portion of the price above June 1973 levels of approximately \$3.05 bbl.

February, 1974

Saskatchewan raised its reference price for royalty calculation purposes by \$0.70/bbl thereby increasing oil royalties by this amount.

Alberta established a new schedule of royalties for natural gas which is graduated with price. Incremental royalty rates begin at 22%, reached 65% at \$0.72/MCF.

Alberta established a new royalty schedule for natural gas discovered after January 1, 1974 (new gas). Incremental royalties begin at 22%, reach 35% at \$0.36/MCF.

April, 1974

Alberta restructured its Crown oil royalty formula by adding to the existing royalty a supplementary levy on price increases. This supplementary levy was set at 65% for the April 1st price increase thus raising the average royalty to 40% compared to the 23% level in March.

Alberta established a separate and lower royalty for oil reserves recognized after January 1, 1974 (new oil). The supplementary levy on price increases above the March 1974 level was set at about 35%.

April, 1974

Saskatchewan increased its royalty surcharge and mineral income tax applicable for the first 3-6 years of production from oil reserves recognized after January 1, 1974 (new oil).

April, 1974

British Columbia revised its royalty schedule increasing the maximum rate to 60% from 40%.

May, 1974

Federal budget proposals, although not enacted as a result of a defeat of Government.

- (1) Provincial and Federal Government royalties mining taxes and similar payments including deemed payments of same made no longer tax deductible.

APPENDIX A (continued)

- (ii) Crown lease rentals previously 100% deductible now subject to 30% amortization.
- (iii) Exploration and development expenses previously 100% deductible now deductible at rate of 30% of unclaimed balance.
- (iv) Reduction in depletion allowance from 33-13% of production profits to the lesser of 33-1/3% of qualifying expenditures or 25% of production profits.
- (v) Increase in rate of tax to 50% from 48% on production profits.
- (vi) The negative effects of items (i)-(v) inclusive were partially offset by the introduction of a new 10% abatement on petroleum profits.

September, 1974

British Columbia Petroleum Corporation increased the field price for new gas to \$0.33/MCF with a further increase to \$0.35/MCF effective January 1, 1975. These changes were equivalent to royalty reductions.

November, 1974

Federal reintroduction, with certain modifications of May 6, 1974 budget proposals as follows:

- (i) Effective May, 1974 Provincial and Federal Government royalties, mining taxes and similar payments including deemed payments of same made no longer tax deductible.
- (ii) Revision effective May 6, 1974, Crown lease rentals now made non-deductible.
- (iii) Effective May 6, 1974 development expenses deductible at rate of 30% of unclaimed balance.
- (iv) Restoration of the pre-May 6, 100% deductibility of exploration expenses.
- (v) Reintroduction of the May 6 proposal to increase the tax rate on production profits to 50% from 48%.
- (vi) Slight revision of the May 6, 10% abatement on petroleum profits to (a) 10% for 1974, (b) 12% for 1975 and (c) 15% for 1976.

December, 1974

Alberta announced:

- (i) Effective January 1, 1975 an increase in the select price component of its oil royalty formula by \$0.60/bbl effectively reducing the average royalty on old oil to 36% from 40%.

APPENDIX A (continued)

- (ii) Effective January 1, 1975 a reduction of the incremental royalty on old gas above a \$0.72/MCF price to 50% from 65%.
- (iii) Effective May 6, 1974 a rebate of the increase in provincial taxes due to the disallowance of royalties paid and deemed paid to the Crown.
- (iv) Effective May 6, 1974 a "royalty tax credit" (maximum of \$1,000,000 per group of associated corporations) to partially offset the federal non-deductibility of federal and provincial royalties and other charges.

December, 1974

Saskatchewan reduced the royalty surcharge for medium and heavy crude oil and for production from marginal wells. A new allowance was also introduced to reflect increased costs of production. Also reduced, the mineral income tax.

Introduction (effective May 6, 1974) of a rebate of the increase in Saskatchewan provincial taxes due to the disallowance of royalties paid and deemed paid to the Crown.

January, 1975

British Columbia announced:

- (i) Effective January 1, 1975 an increase in the corporate rate of tax from 12% to 13%.
- (ii) Introduction of a rebate of the increase in provincial taxes (effective May 6, 1974) due to the disallowance of royalties paid to the Crown and from inclusion in taxable income of "deemed royalty" on the sale of gas to BCPC. The province also proposed to pay the producers' federal income taxes on the royalty deemed paid to BCPC on sales of gas to BCPC.

Alberta incentive credits increased by about 65% with the maximum credit increasing to \$1.9 MM for an 18000 foot foothills test.

Alberta established a geophysical incentives program with credits of \$500, \$1000, or \$1500 per mile of seismic depending on geographic area.

APPENDIX A (continued)

June, 1975

Federal announcement of:

- (i) Introduction of 5% investment tax credit, effective June 24, 1975 - July 1, 1977 for new buildings, machinery and equipment used in a manufacturing and processing business or in the production of petroleum or minerals. Note that credit reduces CCA base.
- (ii) Introduction, effective January 1, 1976 of the standard 46% tax rate of production profits to replace the 50% tax rate and the 15% abatement on production profits - set out in the November, 1974 Budget.
- (iii) Introduction, effective January 1, 1976 of a 25% resource allowance as a partial offset to the non-deductibility of federal and provincial resource levies; i.e., a deduction from production income calculated after deducting operating expenses and capital cost allowance.
- (iv) Introduction, effective June 24, 1975 of a \$0.10 a gallon excise tax on gasoline for personal use. This tax is imposed on producers and importers.

July, 1975

Alberta adjusted its royalty on old oil to capture an average of 50% of the \$1.50/bbl price increase. The change also had the effect of increasing the royalty on the April 1974 price increase somewhat, to offset the reduction in royalty rates that occurred due to lower production rates.

Saskatchewan adjusted its oil royalty to capture about 70% of the price increase, leaving industry with only enough income to pay the increased income tax liability.

November, 1975

British Columbia began to pay gas producers an additional \$0.15/MCF for old gas in the form of transferable credits which may be redeemed for cash by making \$0.20/MCF of exploration and development expenditures in the province.

New gas prices in British Columbia were increased to \$0.55/MCF from \$0.35/MCF.

The British Columbia old oil royalty formula was extensively restructured, but with minimal change in the average rate.

British Columbia established a separate and lower royalty for oil reserves recognized after November 1975 (new oil).

APPENDIX A (continued)

January, 1976

Saskatchewan reduced old oil royalties to about 85% of the December levels. Transferable credits were introduced which may be redeemed in the form of royalty rebates by making exploration and development expenditures in the province.

British Columbia, effective January 1, 1976 increased the corporate rate of tax from 13% to 15%.

British Columbia reduced the "royalty tax rebate" provision effective January 1, 1976 to offset the provincial income tax effect of the "resource allowance" introduced by the federal Government.

March, 1976

Saskatchewan reduced the "royalty tax rebate" provision effective January 1, 1976 to offset the provincial income tax effect of the "resource allowance" introduced by the federal Government.

May, 1976

Alberta reduced the "royalty tax rebate" provision effective January 1, 1976 to offset the provincial income tax effect of the "resource allowance" introduced by the federal Government.

Federal Government announced:

- (i) Improvement in capital cost allowance rates on certain assets such as offshore drilling platforms.
- (ii) Extension (effective May 25, 1976 - July 1, 1979) to all taxpayers and not only principal business corporations of the 100% deductibility of exploration expenses.

July, 1976

Alberta adjusted its royalty on old oil to capture an average of 50% of the \$1.05/bbl price increase. The change also had the effect of slightly reducing royalties on the two previous general price increases. This was intended to reflect an anticipated increase in royalty rates due to increased production.

Saskatchewan old oil royalties were adjusted to capture about 50% of the \$1.05/bbl price increase.

November, 1976

Saskatchewan introduced a new oil royalty formula for Crown production consolidating the former basic royalty, royalty surcharge, marginal well allowance, and increased cost allowance. At the same time, the mineral income tax deductions were consolidated. These changes did not significantly affect royalty levels.

APPENDIX A (continued)

January, 1977

British Columbia raised field prices for old gas to \$0.65/MCF from \$0.35/MCF. The requirement to earn \$0.15/MCF of this price by exploration and development in British Columbia was continued. The price increase, which is equivalent to a royalty reduction, was partially offset by termination by British Columbia of indemnification for federal taxes on the excess of the marketed price of the gas over the price actually paid in British Columbia to the producers.

New gas price in British Columbia were increased to \$0.85/MCF from \$0.55/MCF.

British Columbia old oil royalties were reduced to an average of 40% from 47%.

January, 1977

Alberta adjusted its royalty on old oil to capture an average of 50% of the \$0.70/bbl price increase. The change also had the effect of slightly increasing royalties on all prior general price increases to offset a reduction in royalty rates resulting from production rates.

Alberta amended its royalty regulations to permit companies instituting enhanced oil recovery schemes to deduct certain incremental costs from revenues before calculating royalties.

January, 1977

Saskatchewan adjusted its royalty parameters to capture 55% of the \$.70/barrel price increase.

March, 1977

Federal government announced:

- (i) Introduction of an additional earned depletion entitlement of $66\frac{2}{3}\%$ of drilling cost in excess of \$5 million for an exploration well.
- (ii) Introduction, effective May 6, 1974, of a change in the provision applying to disallowed royalty so that it applies only to amounts imposed by statute.
- (iii) Extension of 5% investment tax credit (originally announced June, 1975) until June 30, 1980. Certain research and development expenditures now qualify for credit. Credit is increased for investments in designated areas. Note that credit reduces CCA base.
- (iv) Introduction, commencing with the 1977 taxation year, of a deduction of 3% of the value of the opening inventory of tangible, moveable property in determining taxable income.

APPENDIX A (continued)

July, 1977

Alberta adjusted its royalty on old oil to capture an average of 50% of the \$1.00/barrel price increase. The change also had the effect of slightly increasing royalties on all prior general price increases to offset a reduction in royalty rates resulting from lower production rates.

Saskatchewan adjusted its royalty parameters to capture 55% of the \$1.00/barrel price increase.

November, 1977

British Columbia raised the field price for old gas to \$0.78/MCF. The requirement to earn \$0.15/MCF of this price (the credit) by exploration and development in British Columbia was discontinued. The new gas price was raised to \$1.03/MCF. Old and new gas prices are to be adjusted monthly to maintain the level of after-tax revenues to the producer.

January, 1978

Saskatchewan adjusted its royalty parameters to capture an average of 55% of the \$1.00/bbl price increase.

Alberta adjusted its royalty on old oil to capture an average of 50% of the \$1.00/barrel price increase. The change also had the effect of slightly increasing royalties on all prior general price increases to offset a reduction in royalty rates resulting from lower production rates.

Alberta extended its drilling incentive program to March 31, 1981 and increased the credits by about 35%. The maximum credit increased to \$2.6 MM for an 18,000-foot foothills test.

British Columbia old oil royalties were reduced to an average of 30% from 40%. The \$0.75/bbl credit earned by exploration and development was discontinued.

April, 1978

Alberta extended its geophysical incentives program to March 31, 1980 with a 50% reduction in the credits.

Federal budget provided for 50% depletion allowance deduction for enhanced recovery facility investments including conventional oil tertiary projects and the tangible injection and production facilities for in situ oil sands projects. Depletion limited to 50% of corporate income (resource and non-resource) after deduction of normal depletion.

July, 1978

Alberta adjusted its royalty on old oil to capture an average of 50% of the \$1.00/bbl price increase.

Saskatchewan adjusted its royalty parameters to capture an average of 55% of the \$1.00/bbl price increase. However, considering the termination of royalty relief for certain operating cost items, the province captured 71% of the price increase.

APPENDIX A (continued)

- August, 1978 Alberta reduced the royalty payable on non-associated gas from wells producing less than 250 MCF/D. Whereas all wells previously paid royalties in the 40% range, marginal producers now pay a declining rate (with volume) to as low as 5%.
- September, 1978 Saskatchewan implemented the Oil Well Income Tax Act intended to retain monies previously collected under the royalty surcharge and mineral income tax. The tax will be calculated on a well-by-well basis (or larger units if appropriate) and applied on revenues from the wells, less certain expenses.
- November, 1978 Federal budget changes included:
- (i) Costs incurred after November 16, 1978 to recomplete a producing oil or gas well qualify as Canadian Development Expense rather than current operating expenses.
 - (ii) The incentive for oil and gas drilling funds was extended to December 31, 1981 from its scheduled expiry date of June 30, 1979.
 - (iii) Effective November 16, 1978, the cost of a right, license or privilege to store petroleum, natural gas or other related hydrocarbons will qualify as a Canadian Development Expense (but not earn depletion).
 - (iv) Effective November 16, 1978, the investment tax credit increases from 5% to 7% for non-research assets and to 10% for R & D expenditures. The July 1, 1980 expiry was removed and the credit now runs indefinitely. The credit reduces CCA base.
- July, 1979 Saskatchewan Oil Well Income Tax rate reduced from 60% to 59% for the period September 1, 1978 and thereafter.
- Alberta reduced the royalty rate for old oil produced from low productivity oil wells (less than 1200 barrels per month). Minimum royalty rate reduced from about 10% to zero.
- Alberta adjusted its royalty on old oil to capture an average of 50% of the \$1.00 per barrel increase.
- Saskatchewan adjusted its royalty parameters to capture an average of 55% of the \$1.00 per barrel increase.

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APPENDIX B

ALBERTA EXPLORATORY DRILLING INCENTIVE REGULATIONS

[IF-1]

EXPLORATORY DRILLING INCENTIVE REGULATIONS

Alberta Regulation 378/72
(Filed December 21, 1972)

As Amended By:
Alberta Regulation 25/78
(Filed January 25, 1978)

As Amended By:
Alberta Regulation 76/79
(Filed March 15, 1979)

As Amended By:
Alberta Regulation 102/79
(Filed March 29, 1979)

As Amended By:
Alberta Regulation 255/79
(Filed July 4, 1979)

1. In these regulations,

- (a) "Board" means the Energy Resources Conservation Board;
- (b) "Department" means the Department of Mines and Minerals;
- (c) "incentive wildcat well" means a new-field wildcat well certified by the Board as an incentive wildcat well;
- (d) "licensee" means the person to whom a licence is granted under The Oil and Gas Conservation Act for a well certified as an incentive wildcat well;
- (e) "Minister" means the Minister of Mines and Minerals.
- (f) "twin well", in relation to an incentive wildcat well, means a well
 - (i) the drilling of which commences on or after January 1, 1978,
 - (ii) that is located in the same legal subdivision or drilling spacing unit, whichever is of lesser area, as that in which the incentive wildcat well exists, and
 - (iii) that is drilled to produce crude oil that, in the opinion of the Board, is not initially recoverable from the incentive wildcat well due to inadvertent damage to the well.

[A.R. 25/78]

2. (1) When a licence is granted for drilling a well for oil or gas the Board on the advice of its Geology Department shall decide whether or not the well qualifies as an incentive wildcat well.

(2) Where a well qualifies as an incentive wildcat well under subsection (1), the Board shall so certify and attach a copy of the certification to each copy of the well licence.

(3) Within 30 days of the granting of a licence for a well that did not qualify as an incentive wildcat well, the applicant for the licence may request the Board to review the classification of the well.

(4) Upon conclusion of the review under subsection (3) the Board shall notify the applicant of its decision and if the well qualifies as an incentive wildcat well the Board shall send two copies of the certification to the licensee.

3. (1) A certification lapses 30 days after the date thereof unless the drilling of the well has been commenced.

(2) Where the drilling of an incentive wildcat well is not being conducted to the satisfaction of the Board until completion or abandonment of the well, the Board shall so notify the licensee and thereupon the certification lapses.

(3) When a certification lapses the Board shall inform the Deputy Minister of the Department.

4. (1) When a certification for an incentive wildcat well lapses or when an incentive wildcat well has been abandoned, the Board will consider for certification any well for which a licence has been granted within the area as though the incentive wildcat well had not been certified and in the event of more than one well having been licensed, priority will be determined by the time of receipt of the application for well licence.

(2) After a certification lapses the holder of the well licence may apply to the Board for a new certification and in determining priority under subsection (1) the application shall be treated as though it were an application for well licence.

[IF-1]

(3) Where a well referred to in subsection (1) or (2) qualifies as an incentive wildcat well, the Board shall send two copies of the certification to the licensee.

(4) If a certification is not granted under subsection (3) the holder of a well license may within 30 days request the Board to review the classification of his well and upon conclusion of the review the Board shall notify the holder of its decision and if the well qualifies as an incentive wildcat well the Board shall send two copies of the certification to the licensee.

5. The Board shall send a copy of each certification to the Deputy Minister of the Department.

6. When an incentive wildcat well is completed or abandoned to the satisfaction of the Board, it shall inform the Deputy Minister of the Department

- (a) the date that the well was completed or abandoned, and
- (b) the depth of the well in feet.

7. (1) Subject to subsections (2) and (3), when an incentive wildcat well has been completed or abandoned to the satisfaction of the Board, a credit in accordance with SCHEDULE A shall be established in the records of the Department, in the name of the licensee.

(2) Where an incentive wildcat well is jointly financed and the licensee,

(a) prior to the commencement of drilling, or
(b) forthwith upon certification following a review by the Board,
informs the Department in writing as to the manner of allocation of the credit among the participants, the credit shall be allocated and established accordingly.

(3) If an amendment to a well licence is obtained to deepen an incentive wildcat well beyond the formation originally authorized by the well licence, the credit with respect to the deepened portion of the well shall be established according to subsection (1) or (2) unless prior to the termination of drilling the well, the licensee informs the Department in writing as to the manner of allocation of the credit relating to the deepened portion of the well, and thereupon the credit shall be allocated and established accordingly.

(4) The licensee in allocating credit under subsection (2) or (3) shall not allocate more than 20 per cent of the credit to those participants who do not contribute to the actual cost of drilling the well.

(5) Subject to subsection (6), credit established under this section is not transferrable.

[A.R. 102 79]

(6) Any credit held in the records of the Department in the name of a licensee or of a participant to whom credit has been allocated under this section may be transferred to any other person if that other person provides evidence satisfactory to the Minister

- (a) that he has acquired all the agreements made or entered into under Part 5 of The Mines and Minerals Act of the licensee or participant in whose name the credit is being held, and
- (b) that the licensee or participant in whose name the credit is being held has ceased to carry on any exploration for or development and production of petroleum or natural gas in Alberta.

[A.R. 76/79]

8. A credit shall not be established for any incentive wildcat well the drilling of which

- (a) commenced prior to August 1, 1972, or
- (b) is continuing after December 31, 1977.

9. Credit established pursuant to section 7, upon the written request of the holder thereof, may be applied in satisfaction of

- (a) moneys payable by him pursuant to dispositions to which Part 5 of The Mines and Minerals Act applies, or
- (b) taxes levied under The Freehold Mineral Taxation Act.

[A.R. 25/78]

10. (1) Crude oil production obtained from an incentive wildcat well, the drilling of which commenced before February 1, 1974 and attributable to its drilling spacing unit, shall be exempt from payment of royalty to the Crown for each of the initial 60 months for which an allowable has been granted to the well by the Board commencing with the month in which the well first produces crude oil for any purpose.

[IF-1]

(2) At the discretion of the Minister, the royalty exemption in subsection (1) may be transferred from an incentive wildcat well to its twin well for the exemption period less the number of allowable months in which crude oil production from the incentive wildcat well has occurred.

(2.1) At the discretion of the Minister the royalty exempted crude oil production under subsection (1) may be produced from a production entity in the same pool as the incentive wildcat well for the exemption period less the number of allowable months in which crude oil production from the incentive wildcat well has occurred.

(3) The royalty exemption on crude oil production from an incentive wildcat well under subsection (1) terminates upon the transfer of the exemption under subsection (2).

[A.R. 25 78]

[A.R. 255:79]

11. Where the drilling of an incentive wildcat well commenced between May 1, 1972 and February 1, 1974 and the well is completed as a crude oil producer, the drilling spacing unit for the well shall be exempt from the tax, if any, payable under The Mineral Taxation Act, 1972 or The Freehold Mineral Taxation Act with respect to petroleum rights for a period of 5 calendar years immediately following the year in which the well was completed.

[A.R. 25 78]

12. Each certification heretofore issued by the Board for a new-field wildcat well or for a certified wildcat well and subsisting at the commencement of these regulations is deemed to be a certification for an incentive wildcat well under these regulations.

13. A decision of the Board under these regulations is final.

SCHEDULE A

The credit in dollars for drilling an incentive wildcat well shall be the number determined by adding 4,500 to the quotient obtained by dividing 1,350 into the square of the depth of the well in feet

$$\text{Credit (in dollars)} = 4,500 + \frac{(\text{Depth})^2}{1,350}$$

EXPLORATORY DRILLING INCENTIVE REGULATIONS, 1974

under

**THE MINES AND MINERAL ACT
THE FREEHOLD MINERAL TAXATION ACT**

**Alberta Regulation 18/74
(Filed January 31, 1974)**

**As Amended By:
Alberta Regulation 50/75**

**As Amended By:
Alberta Regulation 231/76**

**As Amended By:
Alberta Regulation 26/78**

**As Amended By:
Alberta Regulation 81/79
(Filed March 15, 1979)**

**As Amended By:
Alberta Regulations 238/79 and 256/79
(Filed July 4, 1979)**

**As Amended By:
Alberta Regulation 277/79
(Filed August 1, 1979)**

1. In these regulations,

- (a) "Board" means the Energy Resources Conservation Board;
- (b) "class A footage" and "class B footage" mean the respective intervals of depth that are deemed by the Board to qualify for credit of an incentive exploratory well in accordance with section 6 of these regulations;
- (c) "crude oil" means crude oil as defined under The Oil and Gas Conservation Act;
- (d) "Department" means the Department of Mines and Minerals;
- (e) "gas" means gas as defined under The Oil and Gas Conservation Act and includes "condensate" as defined under The Oil and Gas Conservation Act;
- (f) "incentive exploratory well" means a well certified by the Board as an incentive exploratory well under these regulations;
- (g) "licensee" means the person to whom a licence is granted under The Oil and Gas Conservation Act for a well certified as an incentive exploratory well;
- (h) "Minister" means the Minister of Mines and Minerals;
- (i) "plains area", "northern area" and "foothills area" mean the respective areas of Alberta defined in SCHEDULE C to these regulations;
- (j) "twin well", in relation to an incentive exploratory well, means a well
 - (i) the drilling of which commences on or after January 1, 1978.
 - (ii) that is located in the same legal subdivision or drilling spacing unit, whichever is of lesser area, as that in which the incentive exploratory well exists, and
 - (iii) that is drilled to produce crude oil or gas that, in the opinion of the Board, is not initially recoverable from the incentive exploratory well due to inadvertent damage to that well.

[A.R. 231 76]

[A.R. 26 78]

2. (1) Where

- (a) a licence is granted after January 1, 1974 for the drilling of a well for oil or gas and the drilling of the well commenced before January 1, 1978, or
- (b) a licence is amended after August 1, 1976 for the purpose of deepening a well beyond the depth initially referred to in the licence and the deepening of the well commenced before January 1, 1978

the Board shall determine whether or not the well qualifies as an incentive exploratory well under these regulations.

[IF-2]

(2) Where a well qualifies as an incentive exploratory well under subsection (1), the Board shall so certify and attach a copy of the certification to each copy of the well licence.

(3) The applicant for the licence may, within 30 days of a determination by the Board that the well does not qualify as an incentive exploratory well, request the Board to review the eligibility of that well for certification.

(4) The Board shall notify the applicant for the licence of its decision under subsection (3) and where the well qualifies as an incentive exploratory well the Board shall send one copy of the certificate to the licensee.

[A.R. 231 76]

[A.R. 26 78]

3. (1) A certification lapses 30 days after the date thereof unless the drilling of the well has been commenced.

(2) Where the drilling of an incentive exploratory well is not being conducted to the satisfaction of the Board until completion or abandonment of the well, the Board shall so notify the licensee and thereupon the certification lapses.

(3) When a certification lapses the Board shall inform the Department.

4. (1) When a certification for an incentive exploratory well lapses the holder of the well licence may, within 30 days after the date on which certification lapses, apply to the Board for a new certification and if the well qualifies as an incentive exploratory well the Board shall so certify subject to subsections (2) and (3).

(2) If any other well has been licenced and certified in the area influenced by the well for which an application for new certification is made under subsection (1), the Board will determine the amount of qualifying footage for the well as though the existing incentive exploratory well had not been certified, and in the event of more than one well having been licensed and certified, priority for credit will be determined by the date of certification.

(3) For the purpose of determining priority for credit between a well under subsection (1) and a well under subsection (2), the application for new certification under subsection (1) shall be treated by the Board as though it were an initial application for well licence and certification.

(4) Where the well referred to in subsection (1) or (2) is certified as an incentive exploratory well, the Board shall send a copy of the certification to the licensee.

[A.R. 231 76]

5. The Board shall send a copy of each certification to the Department.

6. (1) After the drilling of an incentive exploratory well is completed and upon receipt by the Board of all relevant information relating to the well the Board shall determine what intervals of depth, if any, of the well qualify as class A footage and class B footage.

(2) Upon conclusion of the determination under subsection (1) the Board shall notify the licensee of its decision.

(3) The licensee may forthwith advise the Board that he accepts the determination indicated under subsection (2).

(4) Within 30 days of the notification made under subsection (2) the licensee may apply to the Board to review the determination and the application shall be accompanied by particulars to substantiate any alternative determination of class A footage or class B footage made by the licensee.

(5) Upon conclusion of the review under subsection (4) the Board shall notify the licensee of its decision.

7. When an incentive exploratory well is completed or abandoned to the satisfaction of the Board, it shall inform the Department

(a) the date that the well was completed or abandoned.

(b) the depth of the well in feet, and

(c) the intervals of depth that qualify as class A footage or class B footage.

8. (1) When an incentive exploratory well has been completed or abandoned to the satisfaction of the Board, a credit shall be determined by the Department

(a) in accordance with SCHEDULE A or SCHEDULE B, where the well is completed or abandoned prior to January 1, 1975, or

[IF-2]

- (b) in accordance with SCHEDULE D or SCHEDULE E, where the drilling of the well commences on or after January 1, 1975 and the drilling or deepening of the well commences before January 1, 1978, or
- (c) in accordance with SCHEDULE A or SCHEDULE B in respect of footage drilled prior to January 1, 1975 and in accordance with SCHEDULE D or SCHEDULE E in respect of footage drilled on or after January 1, 1975, where the drilling of the well commenced prior to January 1, 1975 but the well is completed or abandoned on or after January 1, 1975,

and the licensee shall be notified of the credit as determined.

(2) The licensee, within 60 days after the notification made under subsection (1) shall inform the Department in writing as to the manner of allocation of the credit among the participants including those referred to in subsection (5), and the credit shall be allocated and established accordingly.

(3) If the licensee fails to inform the Department within 60 days of the manner of allocation of credit, the credit as determined in subsection (1) shall be established in the records of the Department in the name of the licensee.

(4) If an amendment to a well licence is obtained to deepen an incentive exploratory well beyond the formation originally authorized by the well licence, the credit with respect to the deepened portion of the well shall be established according to subsection (2) or (3) unless within 60 days after being notified under subsection (1) the licensee informs the Department in writing as to the manner of allocation of the credit relating to the deepened portion of the well, and thereupon the credit shall be allocated and established accordingly.

(5) The licensee in allocating credit under subsection (2) or (4) shall not allocate more than 20 per cent of the credit to those participants who do not contribute to the actual cost of drilling the well.

(6) Credit established for an incentive exploratory well may, after its allocation, be revised at the discretion of the Minister if the revision is warranted based on information not previously regarded or correctly processed by the Board or the Department.

(7) Subject to subsection (8), credit established under this section is not transferable.

(8) Any credit held in the records of the Department in the name of a licensee or of a participant to whom credit has been allocated under this section may be transferred to any other person if that other person provides evidence satisfactory to the Minister

- (a) that he has acquired all the agreements made or entered into under Part 5 of The Mines and Minerals Act of the licensee or participant in whose name the credit is being held, and
- (b) that the licensee or participant in whose name the credit is being held has ceased to carry on any exploration for or development and production of petroleum or natural gas in Alberta. [A.R. 81 79]

9. A credit shall not be determined under the Schedules to these regulations for any incentive exploratory well the drilling of which is commenced after December 31, 1977. [A.R. 26 78]

10. Credit established pursuant to section 8, upon the written request of the holder thereof, and subject to procedures established by the Department, may be applied in satisfaction of

- (a) moneys payable by him with respect to any applications and dispositions made under Part 5 of The Mines and Minerals Act.
- (b) moneys payable by him pursuant to section 40 of The Mines and Minerals Act, or
- (c) taxes levied under The Freehold Mineral Taxation Act.

and becoming due and payable between January 1, 1974 and December 31, 1987. [A.R. 26 78]

11. (1) Crude oil production

- (a) obtained from the Class A or Class B footage interval of an incentive exploratory well the drilling or deepening of which commenced before January 1, 1978,
- (b) obtained from a pool in which no other well within 4.8 kilometres has been exempted from payment of royalty to the Crown either under these regulations or under Alberta Regulation 378/72, and

(IF-2)

- (c) attributable to the drilling spacing unit of the incentive exploratory well referred to under clause (a),

is exempt from payment of royalty to the Crown for each of the initial 60 months for which an allowable has been granted to the well by the Board commencing with the month in which the well first produces crude oil for any purpose.

(2) At the discretion of the Minister, the royalty exemption under subsection (1) may be transferred from an incentive exploratory well to its twin well for the exemption period less the number of allowable months in which crude oil production from the incentive exploratory well has occurred.

(2.1) At the discretion of the Minister, the royalty exempted crude oil production under subsection (1) may be produced from a production entity in the same pool as the incentive exploratory well for the exemption period less the number of allowable months in which crude oil production from the incentive exploratory well has occurred.

(3) The royalty exemption on crude oil production from an incentive exploratory well under subsection (1) terminates upon the transfer of the exemption under subsection (2).

[A.R. 26/78]

[A.R. 238/79]

[A.R. 256/79]

12. (1) Gas production

- (a) obtained from the Class A or Class B footage interval of an incentive exploratory well the drilling or deepening of which commenced before January 1, 1978,

- (b) obtained from a pool in which no other well within 4.8 kilometres has been exempted from payment of royalty to the Crown under these regulations, and

- (c) attributable to the drilling spacing unit of the incentive exploratory well referred to under clause (a),

is exempt from payment of royalty to the Crown for each of the initial 24 calendar months in which gas production occurs from the well, commencing with the month in which the well first produces gas that is sold or is consumed for some useful purpose.

(2) At the discretion of the Minister, the royalty exemption under subsection (1) may be transferred from an incentive exploratory well to its twin well for the exemption period less the number of calendar months in which gas production from the incentive exploratory well has occurred.

(3) The royalty exemption on gas production from an incentive exploratory well under subsection (1) terminates upon the transfer of the exemption under subsection (2).

(4) Notwithstanding subsections (1) and (3), the exemption provided by this section does not apply in respect of any calendar month occurring after

- (a) the 12-year period following the finished drilling date of the incentive exploratory well, or

- (b) where the Minister extends the 12-year period, that extended period.

[A.R. 26/78]

[A.R. 238/79]

[A.R. 277/79]

13. Where a drilling spacing unit, all or any portion of which is within a tract as defined in The Freehold Mineral Taxation Act, contains an incentive exploratory well that is completed for crude oil production in accordance with the criteria set out in section 11(1)(a) and (b), the petroleum right in the drilling spacing unit for the well or portion thereof within the tract is exempt from the payment of tax respecting petroleum rights under The Freehold Mineral Taxation Act for the initial 5 calendar years in which the petroleum right would otherwise be subject to the payment of tax.

[A.R. 26/78]

14. Where a drilling spacing unit, all or any portion of which is within a tract as defined in The Freehold Mineral Taxation Act, contains an incentive exploratory well that is completed for gas production in accordance with the criteria set out in section 12(1)(a) and (b), the natural gas right in the drilling spacing unit for the well or portion thereof within the tract is exempt from the payment of tax respecting natural gas rights under The Freehold Mineral Taxation Act for the initial 2 calendar years in which the natural gas right would otherwise be subject to the payment of tax.

[A.R. 26/78]

15. A decision of the Board under these regulations is final.

SCHEDULE A

Applicable to Class A Footage

Class A footage shall be determined as being the depth interval of a well that has not been duplicated either by

- (i) a drilled and abandoned well within approximately one and one-half miles, or
- (ii) a completed well or a well that in the opinion of the Board warrants completion, within approximately three miles.

Depth, Feet	Basis for Credit, Plains Area		Basis for Credit, Northern Area		Basis for Credit, Foothills Area	
	Cumulative Dollars	Incremental \$/foot	Cumulative Dollars	Incremental \$/foot	Cumulative Dollars	Incremental \$/foot
0	0		0		0	
		4.00		6.00		8.00
1,000	4,000	4.00	6,000	6.00	8,000	9.00
2,000	8,000	5.00	12,000	7.00	17,000	10.00
3,000	13,000	6.00	19,000	8.00	27,000	11.00
4,000	19,000	7.00	27,000	9.00	38,000	12.00
5,000	26,000	8.00	36,000	11.00	50,000	14.00
6,000	34,000	10.00	47,000	13.00	64,000	17.00
7,000	44,000	15.00	60,000	19.00	81,000	23.00
8,000	59,000	20.00	79,000	23.00	104,000	28.00
9,000	79,000	26.00	102,000	30.00	132,000	36.00
10,000	105,000	35.00	132,000	40.00	168,000	48.00
11,000	140,000	47.00	172,000	50.00	216,000	56.00
12,000	187,000	62.00	222,000	66.00	272,000	72.00
13,000	249,000	83.00	288,000	85.00	344,000	96.00
14,000	332,000	110.00	373,000	107.00	440,000	120.00
15,000	442,000	147.00	480,000	148.00	560,000	160.00
16,000	589,000	196.00	628,000	184.00	720,000	200.00
17,000	785,000	255.00	812,000	228.00	920,000	240.00
18,000	1,040,000	340.00	1,040,000	316.00	1,160,000	320.00

[1F-2]

SCHEDULE B
Applicable to Class B Footage

Class B footage shall be determined as being the depth interval of a well that has been duplicated by the deepest drilled and abandoned well within approximately one and one-half miles, providing that such depth interval has not been duplicated within approximately three miles by a completed well or a well that in the opinion of the Board warrants completion.

Depth, Feet	Basis for Credit, Plains Area		Basis for Credit, Northern Area		Basis for Credit, Foothills Area	
	Cumulative Dollars	Incremental \$/foot	Cumulative Dollars	Incremental \$/foot	Cumulative Dollars	Incremental \$/foot
0	0		0		0	
1,000	3,000	3.00	4,000	4.00	6,000	6.00
2,000	6,000	3.00	9,000	5.00	13,000	7.00
3,000	10,000	4.00	14,000	5.00	21,000	8.00
4,000	14,000	4.00	20,000	6.00	29,000	8.00
5,000	19,000	5.00	27,000	7.00	38,000	9.00
6,000	25,000	6.00	35,000	8.00	49,000	11.00
7,000	33,000	8.00	45,000	10.00	62,000	13.00
8,000	44,000	11.00	59,000	14.00	78,000	16.00
9,000	59,000	15.00	77,000	18.00	99,000	21.00
10,000	79,000	20.00	99,000	22.00	126,000	27.00
11,000	105,000	26.00	129,000	30.00	162,000	36.00
12,000	140,000	35.00	167,000	38.00	204,000	42.00
13,000	187,000	47.00	216,000	49.00	258,000	54.00
14,000	249,000	62.00	280,000	64.00	330,000	72.00
15,000	332,000	83.00	360,000	80.00	420,000	90.00
16,000	442,000	110.00	471,000	111.00	540,000	120.00
17,000	589,000	147.00	609,000	138.00	690,000	150.00
18,000	780,000	191.00	780,000	171.00	870,000	180.00
		255.00		237.00		240.00

SCHEDULE C

FOOTHILLS AREA

The Foothills Area consists of the lands in Alberta listed below and those lands within Alberta located south and west of the listed lands:

Township 1, Range 24; Township 2, Range 25; Township 3, Range 26; Township 4, Range 27; Township 5, Range 28; and Townships 6 to 11 inclusive, Range 29, all west of the 4th Meridian;

and

Townships 12 and 13, Range 1; Townships 14 to 20 inclusive, Range 2; Townships 21 and 22, Range 3; Townships 23 to 28 inclusive, Range 4; Townships 29 and 30, Range 5; Townships 31 to 34 inclusive, Range 6; Townships 35 and 36, Range 7; Township 37, Range 8; Township 38, Range 9; Townships 39 and 40, Range 10; Township 41, Ranges 11, 12 and 13 inclusive; Township 42, Range 14; Township 43, Ranges 15 and 16; Township 44, Range 17; Townships 45 and 46, Range 18; Townships 47 and 48, Range 19; Township 48, Range 20; Township 49, Ranges 21 and 22; Township 50, Range 23; Townships 51 and 52, Range 24; Townships 53 and 54, Range 25; Township 54, Range 26; Townships 55 and 56, Range 27, all west of the 5th Meridian;

and

Township 56, Range 1; Townships 57 and 58, Range 2; Township 58, Range 3; Townships 59 and 60, Range 4; Township 60, Ranges 5 and 6; Township 61, Ranges 7 and 8; Township 62, Ranges 9 and 10; Township 63, Range 11; Townships 64 and 65, Range 12; and Township 66, Ranges 13 and 14, all west of the 6th Meridian.

PLAINS AREA

The Plains Area consists of the lands in Alberta contained within the outer perimeter of the lands listed below:

On the east by Townships 1 to 66 inclusive, Range 1, west of the 4th Meridian;

and

On the north by Township 66, Ranges 1 to 27 inclusive, all west of the 4th Meridian, and Township 66, Ranges 1 to 4 inclusive, and Township 34, Range 5, all west of the 5th Meridian;

and

On the west from Townships 35 to 66 inclusive, Range 4, west of the 5th Meridian;

and

On the west from Townships 1 to 34 inclusive, the lands immediately adjacent to the FOOTHILLS AREA,

and

On the south by Township 1, Ranges 1 to 23 inclusive, all west of the 4th Meridian.

NORTHERN AREA

The Northern Area consists of the remaining lands in Alberta not included in the FOOTHILLS AREA or the PLAINS AREA.

[A.R. 231/76]

SCHEDULE D

Applicable to Class A Footage

Class A footage shall be determined by the Board as being the depth interval of an incentive exploratory well that

- (i) has not been duplicated by a drilled and abandoned well within either one and one-half miles or a somewhat greater distance as defined by the Board,
- (ii) occurs more than 500 feet below the base of the deepest accumulation of crude oil or natural gas that in the opinion of the Board has been penetrated by another well within either three miles or a somewhat greater distance as defined by the Board, and
- (iii) occurs immediately below the base of the member or formation containing the deepest oil sands deposit that in the opinion of the Board may underlie the location of the said incentive exploratory well.

Where neither (ii) nor (iii) above applies, the Class A footage shall be determined from ground level to the total depth of the said incentive exploratory well.

Depth, Feet	Basis for Credit, Plains Area		Basis for Credit, Northern Area		Basis for Credit, Foothills Area	
	Cumula- tive Dollars	Incre- mental \$/Foot	Cumula- tive Dollars	Incre- mental \$/Foot	Cumula- tive Dollars	Incre- mental \$/Foot
0	0		0		0	
		6.00		15.00		20.00
1,000	6,000		15,000	10.00	20,000	15.00
2,000	13,000	7.00	25,000	10.00	35,000	15.00
3,000	21,000	8.00	35,000	10.00	50,000	15.00
4,000	31,000	10.00	45,000	10.00	65,000	15.00
5,000	42,000	11.00	60,000	15.00	85,000	20.00
6,000	55,000	13.00	75,000	15.00	105,000	20.00
7,000	75,000	20.00	100,000	25.00	135,000	30.00
8,000	100,000	25.00	130,000	30.00	175,000	40.00
9,000	130,000	30.00	170,000	40.00	220,000	45.00
10,000	170,000	40.00	220,000	50.00	280,000	60.00
11,000	230,000	60.00	280,000	60.00	360,000	80.00
12,000	300,000	70.00	370,000	90.00	460,000	100.00
13,000	400,000	100.00	480,000	110.00	580,000	120.00
14,000	530,000	130.00	620,000	140.00	740,000	160.00
15,000	700,000	170.00	800,000	180.00	950,000	210.00
16,000	900,000	200.00	1,000,000	200.00	1,200,000	250.00
17,000	1,200,000	300.00	1,300,000	300.00	1,500,000	300.00
18,000	1,600,000	400.00	1,700,000	400.00	1,900,000	400.00
		400.00		400.00		400.00

[A.R. 50/75]

SCHEDULE E

Applicable to Class B Footage

Class B footage shall be determined by the Board as being the depth interval of an incentive exploratory well that

- (i) has been duplicated by a drilled and abandoned well within either one and one-half miles or a somewhat greater distance as defined by the Board,
- (ii) occurs more than 500 feet below the base of the deepest accumulation of crude oil or natural gas that in the opinion of the Board has been penetrated by another well within either three miles or a somewhat greater distance as defined by the Board, and
- (iii) occurs immediately below the base of the member or formation containing the deepest oil sands deposit that in the opinion of the Board may underlie the location of the said incentive exploratory well.

Where neither (ii) nor (iii) above applies, the Class B footage shall be determined from ground level to the total depth of the said incentive exploratory well.

Depth, Feet	Basis for Credit, Plains Area		Basis for Credit, Northern Area		Basis for Credit, Foothills Area	
	Cumula- tive Dollars	Incre- mental \$/Foot	Cumula- tive Dollars	Incre- mental \$/Foot	Cumula- tive Dollars	Incre- mental \$/Foot
0	0		0		0	
		5.00		11.00		14.00
1,000	5,000	5.00	11,000	8.00	14,000	13.00
2,000	10,000	6.00	19,000	7.00	27,000	11.00
3,000	16,000	7.00	26,000	8.00	38,000	11.00
4,000	23,000	9.00	34,000	11.00	49,000	15.00
5,000	32,000	10.00	45,000	12.00	64,000	15.00
6,000	42,000	14.00	57,000	18.00	79,000	22.00
7,000	56,000	19.00	75,000	23.00	101,000	30.00
8,000	75,000	25.00	98,000	30.00	131,000	34.00
9,000	100,000	30.00	128,000	37.00	165,000	45.00
10,000	130,000	40.00	165,000	45.00	210,000	60.00
11,000	170,000	55.00	210,000	68.00	270,000	75.00
12,000	225,000	75.00	278,000	82.00	345,000	90.00
13,000	300,000	100.00	360,000	105.00	435,000	120.00
14,000	400,000	125.00	465,000	135.00	555,000	155.00
15,000	525,000	150.00	600,000	150.00	710,000	190.00
16,000	675,000	225.00	750,000	225.00	900,000	225.00
17,000	900,000	300.00	975,000	300.00	1,125,000	300.00
18,000	1,200,000	300.00	1,275,000	300.00	1,425,000	300.00

EXPLORATORY DRILLING INCENTIVE REGULATION, 1978

under

**The Mines and Minerals Act
The Freehold Mineral Taxation Act
Alberta Regulation 27/78
(filed January 25, 1978)**

**As Amended by:
Alberta Regulation 82/79
(filed March 15, 1979)**

**As Amended by:
Alberta Regulations 236/79 and 239/79
(filed July 4, 1979)**

**As Amended by:
Alberta Regulations 278/79 and 279/79
(filed August 1, 1979)**

1. In this regulation,
 - (a) "Board" means the Energy Resources Conservation Board;
 - (b) "Class A interval" and "Class B interval" mean the respective intervals of depth of an incentive exploratory well that are determined by the Board to qualify for credit in accordance with section 5 of this regulation and Schedules F and G of this regulation;
 - (c) "crude oil" means crude oil as defined in The Oil and Gas Conservation Act;
 - (d) "Department" means the Department of Energy and Natural Resources;
 - (e) "former regulation" means Alberta Regulation 18/74, as amended, or Alberta Regulation 378/72;
 - (f) "gas" means gas as defined in The Oil and Gas Conservation Act and includes condensate as defined in The Oil and Gas Conservation Act;
 - (g) "incentive exploratory well" means a well certified by the Board as an incentive exploratory well under this regulation;
 - (h) "licensee" means the holder of a licence granted under The Oil and Gas Conservation Act for a well certified as an incentive exploratory well;
 - (i) "Minister" means the Minister of Energy and Natural Resources;
 - (j) "Plains Area", "Central Area", "Northern Area" and "Foothills Area" mean the respective areas of Alberta defined in Schedule H of this regulation;
 - (k) "pre-existing well", in relation to an incentive exploratory well, means
 - (i) a well drilled under a certificate issued under a former regulation or under this regulation before the date and time of the issuance of the certificate under which the incentive exploratory well is drilled, or
 - (ii) an uncertified well the drilling of which commenced before the issuance of the certificate under which the incentive exploratory well is drilled;
 - (l) "twin well", in relation to an incentive exploratory well, means a well
 - (i) the drilling of which commences on or after January 1, 1978,
 - (ii) that is located in the same legal subdivision or drilling spacing unit, whichever is of lesser area, as that in which the incentive exploratory well exists, and
 - (iii) that is drilled to produce crude oil or gas that, in the opinion of the Board, is not initially recoverable from the incentive exploratory well due to inadvertent damage to that well;
 - (m) "uncertified well" means a well drilled for oil or gas in respect of which no certificate is in effect under this regulation or a former regulation at the time of drilling or deepening of the well commenced.

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2. (1) Where

- (a) a licence is granted for the drilling of a well for oil or gas and the drilling of the well commences on or after January 1, 1978, or
- (b) a licence is amended for the purpose of deepening a well beyond the depth initially referred to in the licence and the deepening of the well commences on or after January 1, 1978,

the Board shall determine whether or not the well qualifies as an incentive exploratory well under this regulation.

(2) Where the Board determines that the well qualifies as an incentive exploratory well under subsection (1), the Board shall so certify, attach a copy of the certificate to each copy of the well licence, and send a copy of the certificate to the Department.

(3) The holder of a well licence may, within 30 days of a determination by the Board that the well does not qualify as an incentive exploratory well, submit a written request to the Board to review the eligibility of that well for certification.

(4) A request submitted under subsection (3) shall be accompanied by reasons and particulars in support of the certification of the well.

(5) After the Board concludes a review made under subsection (3),

- (a) the Board shall notify the holder of the well licence of its decision, and
- (b) where the Board determines that the well qualifies as an incentive exploratory well, the Board shall send one copy of the certificate to the licensee and one copy to the Department.

3. (1) A certificate lapses 30 days after the date thereof unless before the expiry of the 30-day period the drilling or deepening of the incentive exploratory well has commenced.

(2) Where the drilling or deepening of an incentive exploratory well is not being conducted to the satisfaction of the Board, the Board shall so notify the licensee and thereupon the certificate lapses.

(3) When a certificate lapses the Board shall inform the Department.

4. When a certificate for an incentive exploratory well lapses the holder of the well licence may apply to the Board for a new certificate and if the Board determines that the well qualifies as an incentive exploratory well under section 2(1) the Board shall issue the new certificate.

5. (1) After the drilling of an incentive exploratory well is completed and upon receipt of the Board of all relevant information relating to the well, the Board shall

- (a) determine what intervals of depth, if any, of the well qualify as a Class A interval and a Class B interval, and
- (b) subject to subsection (2), promptly notify the licensee of the results of its determination.

(2) Where a determination under subsection (1)(a) is based in whole or in part on data or information from a pre-existing well which has not been made available to the public by the Board, the Board may withhold from the licensee the results of its determination under subsection (1) until such times as it releases to the public the data or information respecting the pre-existing well.

(3) The licensee shall either

- (a) advise the Board that he accepts and attests to the accuracy of the determination made under subsection (1),
- (b) indicate to the Board any factors which might warrant a reduction in the Class A or Class B interval determined under subsection (1), or
- (c) within 30 days of the notification given under subsection (1) or (2) apply to the Board to review the determination.

(4) An application made under subsection (3)(c) shall be accompanied by particulars to substantiate any alternative determination of the Class A interval or the Class B interval.

(5) Where the Board reviews a determination made under subsection (1), it shall upon conclusion of the review, notify the licensee of its decision.

6. Where the drilling of an incentive exploratory well is completed under a new certificate issued under section 4 and

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- (a) the new certificate was issued subsequent to the issuance of a certificate for another well within 4.8 kilometres of the incentive exploratory well, and
 - (b) the certificate for the other well is in force and effect when the drilling of the other well commences,
- the Board shall, in determining the Class A interval and the Class B interval, if any, of the incentive exploratory well take into account the location and depth of the other well and the depth of the deepest significant occurrence of crude oil or gas penetrated by the other well.

[A.R. 239/79]

7. The Class A interval and Class B interval, if any, determined for an incentive exploratory well is governed by and subject to

- (a) the existence and depth of any pre-existing well within 2.4 kilometres of the incentive exploratory well,
- (b) the depth of the base of the deepest significant occurrence of crude oil or gas penetrated by any pre-existing well within 4.8 kilometres of the incentive exploratory well, and
- (c) the existence of the deepest oil sands deposit that in the opinion of the Board may underlie the location of the incentive exploratory well.

[A.R. 239/79]

8. When an incentive exploratory well is completed or abandoned to the satisfaction of the Board and the licensee has complied with section 5(3), the Board shall inform the Department of

- (a) the date that the well was completed or abandoned,
- (b) the depth of the well or, where applicable, of the deepened portion of the well referred to in section 2(1)(b),
- (c) the intervals of depth of the well that qualify as a Class A interval or a Class B interval, and
- (d) the basis for determining the qualifying intervals.

9. Upon receipt of the information furnished by the Board pursuant to section 8, the Department shall determine a credit for the incentive exploratory well in accordance with Schedule F or Schedule G, or both, and the licensee shall be notified of the credit as determined.

10. (1) The licensee, within 60 days after the notification given under section 9, shall inform the Department in writing as to the manner of allocation of the credit among the persons specified by the licensee as being participants in the well, and subject to subsection (4), the credit shall be allocated and established in the records of the Department accordingly.

(2) If the licensee fails to comply with subsection (1), the credit shall be established in the records of the Department in the name of the licensee.

(3) Where a well that is to be deepened beyond, or by more than 500 feet within, the formation originally authorized by the well licence is certified as an incentive exploratory well, the credit applicable to the deepened portion of the well shall be allocated and established in the records of the Department

- (a) where the licensee, within 60 days after the notification given under section 9, informs the Department in writing as to the manner of allocation of the credit, in accordance with the allocation made by the licensee, or
- (b) where the licensee fails to comply with clause (a), in the name of the licensee.

(4) The licensee in allocating a credit under subsection (1) or (3)(a) shall not allocate more than 20 per cent of the credit determined for an incentive exploratory well to those participants who did not, or are not liable to, contribute to the actual cost of drilling the well.

11. Credit determined for an incentive exploratory well may, after its establishment in the records of the Department, be redetermined if in the opinion of the Minister a redetermination is warranted, and the revised credit shall be established in the records of the Department in accordance with the same manner of allocation as was made under section 10 in respect of the credit initially determined.

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12. (1) Subject to subsection (2), credit established in the records of the Department under section 10 or 11 is not transferable.

(2) Any credit held in the records of the Department in the name of a licensee or of a participant to whom credit has been allocated under section 10 or 11 may be transferred to any other person if that other person provides evidence satisfactory to the Minister

- (a) that he has acquired all the agreements made or entered into under Part 5 of The Mines and Minerals Act of the licensee or participant in whose name the credit is being held, and
- (b) that the licensee or participant in whose name the credit is being held has ceased to carry on any exploration for or development and production of petroleum or natural gas in Alberta.

[A.R. 82/79]

13. A credit shall not be determined for any incentive exploratory well the drilling or deepening of which is commenced after March 31, 1981.

14. Credit established in the records of the Department pursuant to section 10 or 11 may, upon the written request of the holder thereof, and subject to procedures established by the Department, be applied in satisfaction of

- (a) money payable by him with respect to any applications made and agreements made or entered into under Part 5 of The Mines and Minerals Act,
- (b) royalty payable on petroleum and natural gas obtained pursuant to an agreement made or entered into under Part 5 of The Mines and Minerals Act,
- (c) interest on money payable under any agreement made or entered into under Part 5 of The Mines and Minerals Act, or
- (d) taxes levied under The Freehold Mineral Taxation Act on petroleum and natural gas rights,

and becoming due and payable on or before December 31, 1987.

15. (1) Crude oil production

- (a) obtained from
 - (i) the Class A interval or Class B interval of an incentive exploratory well the drilling or deepening of which commences before April 1, 1981, or
 - (ii) a crude oil-bearing interval that is partly within and partly without the qualifying interval of an incentive exploratory well the drilling or deepening of which commences before April 1, 1981, where, in the opinion of the Board, the portion within the qualifying interval is capable of initially producing crude oil in paying quantity,
- (b) obtained from a pool in which no other well within 4.8 kilometres has been exempted from payment of royalty to the Crown either under this regulation or a former regulation, and
- (c) attributable to the drilling spacing unit of the incentive exploratory well referred to under clause (a),

is exempt from payment of royalty to the Crown for each of the initial 60 months for which an allowable had been granted to the well by the Board, commencing with the month in which the well first produces crude oil for any purpose.

(2) At the discretion of the Minister, the royalty exemption under subsection (1) may be transferred from an incentive exploratory well to its twin well for the exemption period less the number of allowable months in which crude oil production from the incentive exploratory well has occurred.

(2.1) At the discretion of the Minister the royalty exempted crude oil production under subsection (1) may be produced from a production entity in the same pool as the incentive exploratory well for the exemption period less the number of allowable months in which crude oil production from the incentive exploratory well has occurred.

(3) The royalty exemption on crude oil production from an incentive exploratory well under subsection (1) terminates upon the transfer of the exemption under subsection (2).

[A.R. 236/79]

[A.R. 239/79]

[A.R. 278/79]

16. Crude oil production

- (a) obtained from the depth interval of an incentive exploratory well that extends from ground level to a depth of 2000 feet in circumstances where
 - (i) the well is located in the Northern Area,
 - (ii) the drilling or deepening of the well commences before April 1, 1981,
 - (iii) either no accumulation of crude oil or gas has been penetrated by a pre-existing well within 4.8 kilometres of the incentive exploratory well, or, the base of the deepest accumulation of crude oil or gas penetrated by such a well occurs more than 500 feet above the depth at which the production occurs,
 - (iv) the production occurs below a member or formation containing the deepest oil sands deposit that in the opinion of the Board underlies the location of the incentive exploratory well, and
 - (v) the production is in accordance with section 15(1)(b) and (c),or
- (b) obtained from an uncertified well drilled for oil or gas to a total depth of less than 2000 feet in circumstances where
 - (i) the well is located in the Northern Area,
 - (ii) the drilling of the well commences on or after January 1, 1978, and before April 1, 1981,
 - (iii) either no accumulation of crude oil or gas has been penetrated by another well within 4.8 kilometres the drilling of which commenced before, or the certificate for which was issued before, the commencement of drilling of the uncertified well, or, the base of the deepest accumulation of crude oil or gas penetrated by that other well occurs more than 500 feet above the depth at which the production occurs,
 - (iv) the production occurs below a member or formation containing the deepest oil sands deposit that in the opinion of the Board underlies the location of the uncertified well, and
 - (v) the production is in accordance with section 15(1)(b) and (c),shall, if the holder of the well licence or the licensee, as the case may be, makes application therefor to the Department and the Department approves the application, qualify for the royalty exemption under Section 15.

[A.R. 239/79]

17. (1) Gas production

- (a) obtained from
 - (i) the Class A interval or Class B interval of an incentive exploratory well the drilling or deepening of which commences before April 1, 1981, or
 - (ii) a gas-bearing interval that is partly within and partly without the qualifying interval of an incentive exploratory well the drilling or deepening of which commences before April 1, 1981 where, in the opinion of the Board, the portion within the qualifying interval is capable of initially producing gas in paying quantity,
 - (b) obtained from a pool in which no other well within 4.8 kilometres has been exempted from payment of royalty to the Crown either under this regulation or under Alberta Regulation 18/74, as amended, and
 - (c) attributable to the drilling spacing unit of the incentive exploratory well referred to under clause (a),
- is exempt from payment of royalty to the Crown for each of the initial 12 calendar months in which gas production occurs from the well, commencing with the month in which the well first produces gas that is sold or is consumed from some useful purpose.

(2) At the discretion of the Minister, a royalty exemption under subsection (1) may be transferred from an incentive exploratory well to its twin well for the exemption period less the number of calendar months in which gas production from the incentive exploratory well has occurred.

(3) The royalty exemption on gas production from an incentive exploratory well under subsection (1) terminates upon the transfer of the exemption under subsection (2).

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(4) Notwithstanding subsections (1) to (3), the exemption provided by this section does not apply in respect of any calendar month occurring after

- (a) the 12-year period following the finished drilling date of the incentive exploratory well, or
- (b) where the Minister extends the 12-year period, that extended period.

[A.R. 239/79]

[A.R. 279/79]

18. Where a drilling spacing unit, all or any portion of which is within a tract as defined in The Freehold Mineral Taxation Act, contains an incentive exploratory well that is completed for crude oil production in accordance with the criteria set out in section 15(1)(a) and (b), the petroleum right in the drilling spacing unit for the well or portion thereof within the tract is exempt from the payment of tax respecting petroleum rights under The Freehold Mineral Taxation Act for the initial 5 calendar years in which the petroleum right would otherwise be subject to the payment of tax.

19. Where a drilling spacing unit, all or any portion of which is within a tract as defined in The Freehold Mineral Taxation Act, contains an incentive exploratory well that is completed for gas production in accordance with the criteria set out in section 17(1)(a) and (b), the natural gas right in the drilling spacing unit for the well or portion thereof within the tract is exempt from the payment of tax respecting natural gas rights under The Freehold Mineral Taxation Act for the initial calendar year in which the natural gas right would otherwise be subject to the payment of tax.

[IF-4]

SCHEDULE F

Applicable to the Class A Interval of an Incentive Exploratory Well the Drilling of which Commences on or after January 1, 1978.

The Class A interval of an incentive exploratory well the drilling of which commences on or after January 1, 1978 shall be determined by the Board as the interval below the depth of 2,000 feet that

- (i) has not been duplicated by a pre-existing well within 2.4 kilometres,
- (ii) occurs more than 500 feet below the base of the deepest accumulation of crude oil or gas that in the opinion of the Board has been penetrated by a pre-existing well within 4.8 kilometres, and
- (iii) occurs immediately below the base of the member or formation containing the deepest oil sands deposit that in the opinion of the Board may underlie the location of the incentive exploratory well.

Where neither (ii) nor (iii) above applies, the Class A interval shall be determined from the depth of 2,000 feet to the total depth of the incentive exploratory well.

<i>Basis for Credit.</i> Plains Area			<i>Basis for Credit.</i> Central Area		<i>Basis for Credit.</i> Northern and Foothills Area	
<i>Depth, Feet</i>	<i>Cumulative Dollars</i>	<i>Incre- mental \$/Foot</i>	<i>Cumulative Dollars</i>	<i>Incre- mental \$/Foot</i>	<i>Cumulative Dollars</i>	<i>Incre- mental \$/Foot</i>
2,000	0		0		0	
		20		30		40
3,000	20,000	18	30,000	25	40,000	35
4,000	38,000	18	55,000	25	75,000	40
5,000	56,000	20	80,000	25	115,000	35
6,000	76,000	24	105,000	35	150,000	35
7,000	100,000	30	140,000	40	185,000	50
8,000	130,000	40	180,000	50	235,000	65
9,000	170,000	55	230,000	70	300,000	80
10,000	225,000	75	300,000	90	380,000	100
11,000	300,000	100	390,000	110	480,000	120
12,000	400,000	110	500,000	160	600,000	180
13,000	510,000	160	660,000	200	780,000	210
14,000	670,000	210	860,000	240	990,000	260
15,000	880,000	280	1,100,000	350	1,250,000	350
16,000	1,160,000	340	1,450,000	400	1,600,000	425
17,000	1,500,000	500	1,850,000	550	2,025,000	575
18,000	2,000,000	500	2,400,000	550	2,600,000	575
						575

[A.R. 239/79]

[IF-4]

SCHEDULE G

Applicable to the Class B Interval of an Incentive Exploratory Well and Drilling of which Commences on or after January 1, 1978

The Class B interval of an incentive exploratory well the drilling of which commences on or after January 1, 1978 shall be determined by the Board as the interval below the depth of 2,000 feet that

- (i) has been duplicated by a pre-existing well within 2.4 kilometres,
- (ii) occurs more than 500 feet below the base of the deepest accumulation of crude oil or gas that in the opinion of the Board has been penetrated by a pre-existing well within 4.8 kilometres, and
- (iii) occurs immediately below the base of the member of formation containing the deepest oil sands deposit that in the opinion of the Board may underlie the location of the incentive exploratory well.

Where neither (ii) nor (iii) above applies, the Class B interval shall be determined from the depth of 2,000 feet to the total depth of the incentive exploratory well.

<i>Basis for Credit.</i> Plains Area			<i>Basis for Credit.</i> Central Area		<i>Basis for Credit.</i> Northern and Foothills Area	
<i>Depth.</i> <i>Feet</i>	<i>Cumulative</i> <i>Dollars</i>	<i>Incre-</i> <i>mental</i> <i>\$/Foot</i>	<i>Cumulative</i> <i>Dollars</i>	<i>Incre-</i> <i>mental</i> <i>\$/Foot</i>	<i>Cumulative</i> <i>Dollars</i>	<i>Incre-</i> <i>mental</i> <i>\$/Foot</i>
2,000	0		0		0	
		15		20		28
3,000	15,000	14	20,000	20	28,000	29
4,000	29,000	14	40,000	20	57,000	29
5,000	43,000	14	60,000	19	86,000	24
6,000	57,000	18	79,000	26	110,000	30
7,000	75,000	26	105,000	30	140,000	40
8,000	100,000	30	135,000	40	180,000	45
9,000	130,000	40	175,000	50	225,000	60
10,000	170,000	55	225,000	65	285,000	75
11,000	225,000	65	290,000	90	360,000	95
12,000	290,000	90	380,000	120	455,000	125
13,000	380,000	120	500,000	150	580,000	155
14,000	500,000	160	650,000	180	735,000	190
15,000	660,000	210	830,000	270	925,000	275
16,000	870,000	270	1,100,000	300	1,200,000	310
17,000	1,140,000	360	1,400,000	400	1,510,000	420
18,000	1,500,000	360	1,800,000	400	1,930,000	420

[A.R. 239/79]

SCHEDULE H

FOOTHILLS AREA

The Foothills Area consists of the lands in Alberta listed below and those lands within Alberta located south and west of the listed lands:

Township 1, Range 24; Township 2, Range 25; Township 3, Range 26; Township 4, Range 27; Township 5, Range 28; and Township 6 to 11 inclusive, Range 29; and Townships 12 and 13, Range 30, all west of the 4th Meridian;

and

Townships 12 and 13, Range 1; Townships 14 to 20 inclusive, Range 2; Townships 21 and 22, Range 3; Townships 23 to 28 inclusive, Range 4; Townships 29 and 30, Range 5; Townships 31 to 34 inclusive, Range 6; Townships 35 and 36, Range 7; Township 37, Range 8; Township 38, Range 9; Townships 39 and 49, Range 10; Township 41, Ranges 11, 12 and 13 inclusive; Township 42, Range 14; Township 43, Ranges 15 and 16; Township 44, Range 17; Townships 45 and 46, Range 18; Townships 47 and 48, Range 19; Township 48, Range 20; Township 49, Ranges 21 and 22; Township 50, Range 23; Townships 51 and 52, Range 24; Townships 53 and 54, Range 25; Township 54, Range 26; Townships 55 and 56, Range 27, all west of the 5th Meridian;

and

Township 56, Range 1; Townships 57 and 58, Range 2; Township 58, Range 3; Townships 59 and 60, Range 4; Township 60, Ranges 5 and 6; Township 61, Ranges 7 and 8; Township 62, Ranges 9 and 10; Township 63, Range 11; Townships 64 and 65, Range 12; and Township 66, Ranges 13 and 14, all west of the 6th Meridian.

PLAINS AREA

The Plains Area consists of the lands in Alberta contained within the outer perimeter of the lands listed below:

On the east of Townships 1 to 66 inclusive, Range 1, west of the 4th Meridian;

and

On the north by Township 66, Ranges 1 to 27 inclusive, all west of the 4th Meridian, and Township 66, Ranges 1 to 4 inclusive, and Township 34, Range 5, all west of the 5th Meridian;

and

On the west from Townships 35 to 66 inclusive, Range 4, west of the 5th Meridian;

and

On the west from Townships 1 to 34 inclusive, the lands immediately adjacent to the FOOTHILLS AREA,

and

On the south by Township 1, Ranges 1 to 23 inclusive, all west of the 4th Meridian.

NORTHERN AREA

The Northern Area consists of the lands in Alberta listed below and those lands within Alberta located north and east of the listed lands:

Township 77, Ranges 1 to 26 inclusive, all west of the 4th Meridian;

and

Township 77, Ranges 1 to 12 inclusive; Townships 77 to 79 inclusive, Range 13; Township 80, Ranges 14 to 18 inclusive; Townships 80 to 104 inclusive, Range 18; Township 105, Ranges 19 to 25 inclusive; Township 106, Range 25; Townships 107 to 120 inclusive, Range 24, all west of the 5th Meridian;

and

Township 121, Ranges 1 to 12 inclusive, all west of the 6th Meridian.

CENTRAL AREA

The Central Area consists of the remaining lands in Alberta not included in the FOOTHILLS AREA or the NORTHERN AREA or the PLAINS AREA.

[IF-4]

SCHEDULE I

The metres to feet conversion factor for the purpose of this regulation and SCHEDULES F and G of this regulation is as follows:

1 metre = 3.2808 feet

1 foot = 0.3048 metres

APPENDIX C

ALBERTA GEOPHYSICAL INCENTIVE PROGRAM REGULATIONS

ALBERTA REGULATION 35/75
(Filed February 11, 1975)

AS AMENDED BY
ALBERTA REGULATION 238/76

AS AMENDED BY
ALBERTA REGULATION 170/78

AS AMENDED BY
ALBERTA REGULATION 83/79
(Filed March 15, 1979)

AS AMENDED BY
ALBERTA REGULATION 135/79
(Filed May 2, 1979)

AS AMENDED BY
ALBERTA REGULATION 240/79
(Filed July 4, 1979)

GEOPHYSICAL INCENTIVE PROGRAM REGULATIONS

1. In these regulations.
 - (a) "Department" means the Department of Mines and Minerals;
 - (b) "foothills area", "green area", "yellow area" and "plains area" mean the respective areas of Alberta described in Schedule C to these regulations;
 - (c) "geophysical incentive program" means a seismic survey conducted for the purpose of exploring for petroleum or natural gas or both and certified by the Minister as a geophysical incentive program;
 - (d) "geophysical information and data" means all field data, field reports and the standard processed sections that are stacked after filtering and correction for statics and normal moveout;
 - (e) "licence" means a licence issued pursuant to Part 9 of The Mines and Minerals Act;
 - (f) "licensee" means the holder of a licence;
 - (g) "minimum subsurface coverage" means the coverage obtained when seismic pulses generated from not less than four different source positions are reflected from a subsurface point;
 - (h) "Minister" means the Minister of Mines and Minerals;
 - (i) "seismic survey" means a survey conducted by the use of the geophysical prospecting technique known as the seismic reflection method.
2. These regulations do not apply to a seismic survey the recording of which commenced before January 1, 1975.
3. (1) A licensee may, in accordance with these regulations, apply to the Minister to have a seismic survey certified as a geophysical incentive program.
 - (2) An application under subsection (1) shall be submitted by the licensee and received by the Minister
 - (a) prior to commencing the recording of the seismic survey, or
 - (b) in a case where the recording of the seismic survey commenced on or after January 1, 1975 and before the coming into force of these regulations, not later than February 28, 1975.
 - (3) The application shall be in Form 1 of Schedule A to these regulations.
 - (4) Where a seismic survey initially qualifies as a geophysical incentive program, the Minister shall issue an Interim Certificate in Form 2 of Schedule A to these regulations which shall be attached to the copy of the licence in the records of the Department.
 - (5) A copy of the Interim Certificate shall be sent to the licensee.

[A.R. 238/76]
4. (1) An Interim Certificate lapses one year after the date thereof unless the seismic survey to be conducted under the Interim Certificate has been commenced.
 - (2) An Interim Certificate may be granted for one or more seismic surveys to be conducted thereunder.

5. Where a seismic survey is being conducted under an Interim Certificate, the Minister or any person authorized by him may at any time for the purpose of investigation and inspection have access to all the field data and field reports obtained by the licensee during the course of conducting the seismic survey, and the licensee or his representative shall render to the Minister or the person authorized by him such assistance as may be necessary.

6. (1) Within 90 days of completing a seismic survey or surveys under an Interim Certificate, the licensee shall submit to the Minister a final report in Form 3 of Schedule A to these regulations for each seismic survey so completed.

(2) The final report in subsection (1) shall be executed on behalf of the licensee by a professional geophysicist within the meaning of The Engineering and Related Professions Act.

(3) Where the licensee submits a final report or reports under subsection (1) and the seismic survey or surveys that were the subject of the application under section 3 have been reduced in size, the licensee shall inform the Minister in writing of the extent of the reduction and the Minister shall amend the Interim Certificate accordingly.

(4) Upon receipt of the final report or reports, the licensee shall, at the request of the Minister, make available to the Department for purposes of investigation and inspection all geophysical information and data obtained from each seismic survey completed under the Interim Certificate.

[A.R. 238/76]

7. (1) When the seismic survey or surveys under an Interim Certificate are completed to the satisfaction of the Minister, the Minister shall certify the seismic survey or surveys as a geophysical incentive program and a credit shall be determined by the Minister in accordance with Schedule B to these regulations, and the licensee shall be notified of the credit is determined.

(2) The Minister shall not give a certification or determine a credit under subsection (1) where he is satisfied that

- (a) the seismic survey fails to meet the minimum subsurface coverage, or
- (b) the seismic survey is not conducted in accordance with the standards of good geophysical practices.

(3) When submitting a final report under section 6, the licensee shall inform the Minister in writing as to the manner of allocation of the credit among the participants who have contributed to the actual cost of conducting the survey.

(4) If the licensee fails to inform the Minister of the manner of allocation of the credit, the credit as determined in subsection (1) shall be established in the records of the Department in the name of the licensee.

(5) Subject to section 9, subsection (3), a credit determined under this section is not transferable.

[A.R. 238/76]

[A.R. 135/79]

7.1 (1) The Minister shall not determine a credit under these regulations

- (a) for a seismic survey for which an application for certification is received by the Minister after March 31, 1978, or
- (b) for a seismic survey for which an application for certification was received by the Minister before April 1, 1978, but the final report on which is received by the Minister after June 30, 1978.

(2) The Minister shall determine a credit under these regulations for a seismic survey for which an application for certification was received by the Minister before April 1, 1978, the recording of which commences after March 31, 1978

- (a) where he is satisfied that the seismic survey qualifies for credit under section 7, and
- (b) where the final report on the seismic survey is received by the Minister before July 1, 1978.

[A.R. 170/78]

8. (1) Credit established in the records of the Department pursuant to section 7 may, upon the written request of the holder thereof, and subject to procedures established by the Department, be applied in satisfaction of

- (a) money payable by him with respect to any applications made and agreements made or entered into under Part 5 of The Mines and Minerals Act,
- (b) royalty payable on petroleum and natural gas obtained pursuant to an agreement made or entered into under Part 5 of The Mines and Minerals Act,
- (c) interest on money payable under any agreement made or entered into under Part 5 of The Mines and Minerals Act, or
- (d) taxes levied under The Freehold Mineral Taxation Act on petroleum or natural gas rights,

and becoming due and payable on or before December 31, 1987.

(2) Where a licensee submits a request to the Minister for the monetary equivalent of the credit established in his name in the records of the Department pursuant to section 7 and provides evidence satisfactory to the Minister that he is neither the registered owner under The Land Titles Act of a petroleum or natural gas right as defined in The Freehold Mineral Taxation Act nor the holder of an agreement under Part 5 of The Mines and Minerals Act, the Minister may pay to the licensee upon submission of the request the monetary equivalent of the credit.

(3) Notwithstanding sections 7 and 8, the Minister may withhold from establishment in the records of the Department or from utilization, 25% of the credit determined by the Minister for a geophysical incentive program until the Minister receives evidence satisfactory to him that the program was conducted in accordance with the Geophysical Regulations (Alta. Reg. 26/59), as amended, and that the surface of the land on which the program was conducted has been adequately reclaimed.

[A.R. 197/78]

9. (1) Subject to subsection (2), it is a condition of every Interim Certificate issued under section 3 that the geophysical information and data obtained pursuant to a seismic survey for which the Interim Certificate was issued shall be made available by the licensee under whose licence the survey was conducted 3 years after the date upon which the Interim Certificate was issued for the seismic survey

- (a) to any person requesting the data in writing within 20 days after receipt by the licensee of the written request for the data and thereafter for a period of not less than 5 years, and
- (b) at a cost to that person of
 - (i) \$190 for each kilometre of minimum subsurface coverage in the yellow area or plains area to which the geophysical information and data to be acquired relates,
 - (ii) \$380 for each kilometre of minimum subsurface coverage in the green area to which the geophysical information and data to be acquired relates, and
 - (iii) \$570 for each kilometre of minimum subsurface coverage in the foothills area to which the geophysical information and data to be acquired relates,
 and of the expense of reproducing the geophysical information and data requested.

(2) The minimum amount of geophysical information and data which may be purchased pursuant to a written request under subsection (1) shall be the lesser of the geophysical information and data relating to

- (a) 8 kilometres of minimum subsurface coverage, or
 - (b) the minimum subsurface coverage in a line.
- (3) If a licensee, within the 3-year period referred to in subsection (1),
- (a) withdraws from Alberta and ceases carrying on business in Alberta, or
 - (b) being a corporation, is dissolved or is struck off the register pursuant to The Companies Act,

he shall place in trust with a person approved by the Minister all the geophysical information and data obtained pursuant to seismic surveys for which an Interim Certificate has been issued that were conducted under his licence until the 3-year period has expired, and thereafter for an additional period of 5 years, and any credit held in the name of the licensee in the records of the Department shall be cancelled.

(3) Notwithstanding subsection (2), any credit held in the records of the Department in the name of the licensee or of a participant to whom credit has been allocated under section 7 may be transferred to any other person if that other person provides evidence satisfactory to the Minister

- (a) that he has acquired all the agreements made or entered into under Part 5 of The Mines and Minerals Act of the licensee or participant in whose name the credit is being held, and
- (b) that the licensee or participant in whose name the credit is being held has ceased to carry on any exploration for or development and production of petroleum or natural gas in Alberta.

[A.R. 135/79]

[A.R. 240/79]

10. (1) Where geophysical information and data obtained from a seismic survey conducted under an Interim Certificate for which no credit is determined by the Minister is not made available in accordance with section 9 by the licensee, the Minister may cancel

- (a) his licence,
- (b) his permit, and
- (c) any credit held in his name in the records of the Department.

(2) Where geophysical information and data obtained from a geophysical incentive program for which credit is established in the records of the Department under this regulation is not made available in accordance with section 9 by the licensee, the Minister may cancel

- (a) his licence,
- (b) his permit,
- (c) any credit established for the program in the records of the Department, and
- (d) any credit held in the records of the Department in the name of the licensee.

[A.R. 170/78]

11. Any of the powers of the Minister under these regulations may be exercised by any employee of the Department authorized in writing by the Minister for that purpose.

GEOPHYSICAL INCENTIVE PROGRAM REGULATION, 1978

ALBERTA REGULATION 171/78
(Filed April 26, 1978)

As Amended by
ALBERTA REGULATION 316/78
(Filed August 9, 1978)

As Amended by
ALBERTA REGULATION 84/79
(Filed March 15, 1979)

As Amended by
ALBERTA REGULATION 241/79
(Filed July 4, 1979)

As Amended by
ALBERTA REGULATION 280/79
(Filed August 1, 1979)

1. In this regulation

- (a) "certificate" means a certificate issued for a program under this regulation;
- (b) "Department" means the Department of Energy and Natural Resources;
- (b.1) "exploration licence" means a licence to conduct geophysical exploration issued under Part 9 of The Mines and Minerals Act or a licence to conduct exploration issued under the Exploration Regulation;
- (b.2) "exploration permit" means a permit to operate geophysical equipment issued under the Geophysical Regulations or a permit to operate exploration equipment issued under the Exploration Regulation;
- (b.3) "Exploration Regulation" means the Exploration Regulation filed as Alberta Regulation 423/78, as amended;
- (c) "foothills area", "green area", "yellow area" and "plains area" means the respective areas of Alberta described in Schedule C to this regulation;
- (d) "geophysical incentive program" means a program certified by the Minister as an incentive program under this regulation;
- (e) "geophysical information and data" means all field data, field reports and the standard processed sections that are stacked after filtering and correction for statics and normal moveout;
- (f) "Geophysical Regulations" means the Geophysical Regulations filed as Alberta Regulation 26/59, as amended;
- (h) "licensee" means the holder of a licence under which a program is conducted;
- (i) "line" means a portion of a program;
- (j) "minimum subsurface coverage" means the coverage obtained when seismic pulses generated from not less than 6 different energy source positions in the yellow area and plains area or 10 different energy source positions in the green area and foothills area are reflected from a subsurface point;
- (k) "Minister" means the Minister of Energy and Natural Resources;
- (m) "program" means a program of exploration conducted by the use of the geophysical prospecting technique known as the seismic reflection method for the purpose of exploring for petroleum or natural gas or both.

[A.R. 316/78]

[A.R. 280/79]

2. This regulation applies to a program for which an application for a certificate is received by the Minister before April 1, 1980.

3. (1) A licensee may, in accordance with this regulation, apply to the Minister to have a program certified as a geophysical incentive program.

(2) The application shall be submitted by the licensee and shall be in Form 1 of Schedule A to this regulation.

(3) Where a program qualifies a geophysical incentive program, the Minister shall issue a certificate for the program in Form 2 of Schedule A to this regulation.

(4) A copy of the certificate shall be sent to the licensee.

4. A certificate is subject to the following conditions:

- (a) that the licensee shall allow the Minister, or any person authorized by the Minister for the purpose, to have access to any field data or field reports obtained by the licensee or his representatives during the course of conducting the program, and
- (b) that the licensee and his representatives shall render to the Minister or the person authorized by him under clause (a) such assistance as may be necessary for the purpose of enabling the Minister or that person to inspect the field data or field reports.

5. (1) Within 120 days of completing a geophysical incentive program, or on or before August 1, 1980, whichever is earlier, the licensee shall submit to the Minister a final report on the program in Form 3 of Schedule A to this regulation.

(2) A final report submitted by the licensee under subsection (1) shall be accompanied by a copy of the computer stacking diagram for each line in the program.

(3) The final report on a geophysical incentive program shall be made on behalf of the licensee by a professional geophysicist within the meaning of The Engineering and Related Professions Act.

(4) At any time following submission to the Minister of the final report on a geophysical incentive program, the licensee shall make available to the Department upon request all geophysical information and data obtained from the program.

6. (1) Subject to subsection (3), where a geophysical incentive program

- (a) is conducted under a certificate for which an application is received by the Minister after March 31, 1978, and before April 1, 1980,
- (b) is completed to the satisfaction of the Minister, and
- (c) is reported on within the time and in the manner prescribed by section 5,

the Minister shall

- (d) determine a credit for the program in accordance with Schedule B to this regulation, and
- (e) notify the licensee of the credit as determined.

(2) The number of kilometres upon which a determination of credit for a geophysical incentive program is based shall never exceed the number of kilometres of minimum subsurface coverage approved for the program, but where the number of kilometres of minimum subsurface coverage in a geophysical incentive program as determined from the final report and computer stacking diagrams is less than the number of kilometres approved for the program, the Minister shall base his determination of credit for the program upon the size of the program as ascertained from the computer stacking diagrams.

(3) The Minister shall not determine a credit for a program under subsection (1) where he is satisfied that

- (a) the program fails to meet minimum subsurface coverage,
- (b) the program is not conducted in accordance with generally accepted standards for the conduct of exploration, or
- (c) the recording of the program has commenced before a certificate for the program is issued under section 3.

(4) Subsection 3(c) does not apply to a geophysical incentive program for which an application for certification is received by the Minister during April, 1978.

(5) When submitting a final report on a program under section 5, the licensee shall inform the Minister in writing as to the manner of allocation of the credit among the persons specified by the licensee as being participants who have contributed to the actual cost of conducting the program and, subject to subsection (6) and section 7, the credit shall be allocated and established in the records of the Department accordingly.

(6) If the licensee fails to comply with subsection (5), the credit shall be established in the records of the Department in the name of the licensee.

[A.R. 241/79]

[A.R. 280/79]

7. Notwithstanding sections 6 and 9, the Minister may withhold from establishment in the records of the Department or from utilization 25% of the credit determined by him for a geophysical incentive program until he receives evidence

- (a) that the program conforms in all respects to the Geophysical Regulations, if the program was wholly or substantially conducted before November 22, 1978, or
- (b) that the program conforms in all respects to the Exploration Regulation, if the program is wholly or substantially conducted on or after November 22, 1978,

and that the surface of the land on which the program was conducted has been adequately restored.

[A.R. 280/79]

8. (1) Subject to subsection (2), credit established in the records of the Department under section 6 is not transferable.

(2) Any credit held in the records of the Department in the name of a licensee or of a party to whom credit has been allocated under section 6 may be transferred to any other person if that other person provides evidence satisfactory to the Minister

- (a) that he has acquired all the agreements made or entered into under Part 5 of The Mines and Minerals Act of the licensee or party in whose name the credit is being held, and
- (b) that the licensee or party in whose name the credit is being held has ceased to carry on any exploration for or development and production of petroleum or natural gas in Alberta.

9. (1) Credit established in the records of the Department pursuant to section 6 may, upon the written request of the holder thereof, and subject to procedures established by the Department, be applied in satisfaction of

- (a) money payable by him with respect to any application made and agreements made or entered into under Part 5 of The Mines and Minerals Act,
- (b) royalty payable on petroleum and natural gas obtained pursuant to an agreement made or entered into under Part 5 of The Mines and Minerals Act,
- (c) interest on money payable under any agreement made or entered into under Part 5 of The Mines and Minerals Act, or
- (d) taxes levied under The Freehold Mineral Taxation Act on petroleum or natural gas rights,

and becoming due and payable on or before December 31, 1987.

(2) Where a licensee submits a request to the Minister for the monetary equivalent of the credit being held in the name of the licensee in the records of the Department and provides evidence satisfactory to the Minister that he is neither the registered owner under The Land Titles Act of a petroleum or natural gas right defined in The Freehold Mineral Taxation Act nor the holder of an agreement under Part 5 of The Mines and Mineral Act, the Minister may pay the licensee upon submission of the request the monetary equivalent of the credit.

10. (1) It is a condition of every certificate that geophysical information and data obtained pursuant to the geophysical incentive program for which the certificate is issued shall be made available by the licensee under whose exploration licence the program was conducted 3 years after the date upon which the geophysical incentive program is certified

- (a) to any person requesting the data in writing within 20 days after receipt by the licensee of the written request for the data and thereafter for a period of not less than 5 years, and
- (b) at the cost to that person of
 - (i) \$190 for each kilometre of minimum subsurface coverage in the yellow area or plains area to which the geophysical information and data to be acquired relates,
 - (ii) \$380 for each kilometre of minimum subsurface coverage in the green area to which the geophysical information and data to be acquired relates, and
 - (iii) \$570 for each kilometre of minimum subsurface coverage in the foothills area to which the geophysical information and data to be acquired relates,

and of the expense of reproducing the geophysical information and data requested.

(2) The minimum amount of geophysical information and data which may be purchased pursuant to a written request under subsection (1) shall be the lesser of the geophysical information and data relating to

- (a) 8 kilometres of minimum subsurface coverage, or
 - (b) the minimum subsurface coverage in a line.
- (3) If a licensee, within the 3-year period referred to in subsection (1),
- (a) withdraws from Alberta and ceases carrying on business in Alberta, or
 - (b) being a corporation, is dissolved or is struck off the register pursuant to The Companies Act,

he shall place in trust with a person approved by the Minister all the geophysical information and data obtained pursuant to geophysical incentive programs that were conducted under his exploration licence until the 3-year period has expired, and thereafter for an additional period of 5 years, and any credit held in the name of the licensee in the records of the Department shall be cancelled.

[A.R. 241/79]

[A.R. 280/79]

11. (1) Where geophysical information and data obtained from a geophysical incentive program for which no credit is determined by the Minister under this regulation is not made available in accordance with section 10 by the licensee, the Minister may cancel

- (a) his exploration licence,
- (b) his exploration permit, and
- (c) any credit held in his name in the records of the Department.

(2) Where geophysical information and data obtained from a geophysical incentive program for which credit is established in the records of the Department is not made available in accordance with section 10 by the licensee, the Minister may cancel

- (a) his exploration licence,
- (b) his exploration permit,
- (c) any credit established for the program in the records of the Department, and
- (d) any credit held in the records of the Department in the name of the licensee.

[A.R. 280/79]

12. Any of the powers of the Minister under this regulation may be exercised by any employee of the Department authorized in writing by the Minister for that purpose.

SCHEDULE A

**Form 1
(Section 3)**

**APPLICATION FOR CERTIFICATION OF A PROGRAM AS A
GEOPHYSICAL INCENTIVE PROGRAM.**

DATE: _____

NAME OF LICENSEE: _____

ADDRESS: _____

LICENCE NO. _____

LICENSEE REPRESENTATIVE: _____

TELEPHONE NO. _____

NAME OF PERMITTEE: _____

ADDRESS: _____

PERMIT NO. _____ **PARTY NO.** _____

PROGRAM NO. _____

PROGRAM RECORDING TO COMMENCE: _____

ANTICIPATED PROGRAM RECORDING COMPLETION DATE: _____

ENERGY SOURCE: _____

SOURCE SPACING (Metres): _____

RECEIVER SPACING (Metres): _____

NUMBER OF TRACES: _____

	<u>yellow-plains</u>	<u>green</u>	<u>foothills</u>
KILOMETRES			
PLANNED (Approx.):	_____	_____	_____
INCENTIVE			
ANTICIPATED (Approx.):	_____	_____	_____
TOTAL INCENTIVE			
ANTICIPATED:	_____	_____	_____

Licensee

(Note: Application must be accompanied by a map or maps on a scale of not less than 1:50 000).

[A.R. 241/79]

SCHEDULE A

**Form 2
(Section 3)**

CERTIFICATE NUMBER

DATE: _____

NAME OF LICENSEE: _____

ADDRESS: _____

LICENCE NO. _____ **PERMIT NO.** _____

PROGRAM NO. _____

MAXIMUM NUMBER OF KILOMETRES APPROVED _____

for MINISTER OF ENERGY AND NATURAL RESOURCES

[A.R. 241/79]

SCHEDULE A

Form 3

(Section 5)

FINAL REPORT

LICENSEE: _____

LICENCE NO. _____

ADDRESS: _____

PROGRAM CERTIFICATE NO. _____

PROGRAM CERTIFICATE DATE _____

RECORDING COMMENCEMENT DATE _____

RECORDING COMPLETION DATE _____

PERMITTEE: _____

PERMIT NO.: _____

ADDRESS: _____ PARTY NO.: _____

RECORDING COMMENCEMENT DATE _____

RECORDING COMPLETION DATE _____

AMPLIFIER MAKE _____ MODEL _____

NO. OF TRACES _____

24 48 Other

SOURCE INTERVAL _____ RECEIVER INTERVAL _____

SOURCE TYPE _____

yellow-plains green foothills

No. of kilometres of minimum subsurface coverage. \$160 x 1 x \$160 x 2 x \$160 x 3 x

(Accurate to two places of decimal)

Credit (in dollars) applied for = \$ = \$ = \$ Total \$ _____

I, the undersigned, certify that I am qualified to report on this program and have personal knowledge of and attest to the accuracy of the above report.

*Signature and Seal of
Professional Geophysicist*

A.P.E.G.G.A. Class

(Note: Must be accompanied by a map or maps on a scale of not less than 1:50 000 showing location of data recorded.

A final report must be completed for each program.

[A.R. 241/79]

SCHEDULE B

DETERMINATION OF CREDIT

The credit in dollars for a geophysical incentive program, shall be calculated in accordance with the following equation:

$$\text{Credit (in dollars)} = 160 KM$$

where K is the incentive factor for the area of Alberta described in Schedule C in which the geophysical incentive program was conducted,

and

M is the number of kilometres of minimum subsurface coverage in the area.

Incentive Factors

For the purpose of section 6 and this Schedule, the incentive factors established for the areas of Alberta described in Schedule C are as follows:

- (a) 1 for the yellow area and the plains area,
- (b) 2 for the green area, and
- (c) 3 for the foothills area.

SCHEDULE C

FOOTHILLS AREA

The Foothills Area consists of the lands in Alberta listed below and those lands within Alberta located south and west of the listed lands:

Township 1, Range 24; Township 2, Range 25; Township 3, Range 26; Township 4, Range 27; Township 5, Range 28; and Townships 6 to 11 inclusive, Range 29, all west of the 4th Meridian;

and

Townships 12 and 13, Range 1; Townships 14 to 20 inclusive, Range 2; Township 21 and 22, Range 3; Townships 23 to 28 inclusive, Range 4; Townships 29 and 30, Range 5; Townships 31 to 34 inclusive, Range 6; Townships 35 and 36, Range 7; Township 37, Range 8; Township 38, Range 9; Townships 39 and 40, Range 10; Township 41, Range 11, 12 and 13 inclusive; Township 42, Range 14; Township 43, Ranges 15 and 16; Township 44, Range 17; Townships 45 and 46, Range 18; Townships 47 and 48, Range 19; Township 48, Range 20; Township 49, Ranges 21 and 22; Township 50, Range 23; Townships 51 and 52, Range 24; Townships 53 and 54, Range 25; Township 54, Range 26; Townships 55 and 56, Range 27, all west of the 5th meridian;

and

Township 56, Range 1; Townships 57 and 58, Range 2; Township 58, Range 3; Townships 59 and 60, Range 4; Township 60, Ranges 5 and 6; Township 61, Ranges 7 and 8; Township 62, Ranges 9 and 10; Township 63, Range 11; Townships 64 and 65, Range 12; and Township 66, Ranges 13 and 14, all west of the 6th meridian.

GREEN AREA

The green area consists of that part of Alberta in which public lands are classified as forest land not available for agricultural development other than grazing by an order of the Minister pursuant to Section 12 of The Public Lands Act effective to November 30, 1974, but does not include those lands described in this Schedule as the Foothills Area.

YELLOW AREA

The yellow area consists of that part of Alberta in which public lands are classified as being adaptable to any kind of disposition by an order of the Minister pursuant to Section 12 of The Public Lands Act effective to November 30, 1974.

PLAINS AREA

The plains area consists of the remaining lands in Alberta not described in the Foothills Area, the Green Area or the Yellow Area.

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APPENDIX D

FRONTIER EXPLORATION ALLOWANCES

FRONTIER EXPLORATION ALLOWANCES

1207. (1) A taxpayer may deduct in computing his income for a taxation year such amount as he may claim not exceeding the lesser of

- (a) his income for the year, computed in accordance with Part I of the Act, if no deduction were allowed under this subsection; and
- (b) his frontier exploration base as of the end of the year (before making any deduction under this subsection for the year).

(2) For the purposes of this section, the "frontier exploration base" of a taxpayer as of a particular time means the amount that is equal to

(a) the aggregate of all amounts, each of which is an amount in respect of a particular oil or gas well in Canada equal to 66⅔% of the amount by which

- (i) expenses incurred after March, 1977 and before April, 1980 and before the particular time in respect of the well if those expenses would be included in the Canadian exploration expense of the taxpayer within the meaning of paragraph 66.1(6)(a) of the Act (if that paragraph were read without reference to subparagraph (iii) thereof and without reference to the words "within six months after the end of the year, the drilling of the well is completed and" in subparagraph (ii) thereof, and if the reference in subparagraphs (iv) and (v) thereof to "any of subparagraphs (i) to (iii)" were read as a reference to "subparagraph (i) or (ii)" other than

(A) an amount deemed by section 21 of the Act to be a Canadian exploration expense of the taxpayer,

(B) an expense renounced by the taxpayer under subsection 66(10.1) of the Act,

(C) an amount that, by virtue of subparagraph 66.1(6)(a)(iv) of the Act, was a Canadian exploration expense, if such amount was an expense referred to in clause (A) or (B) that was incurred by an association, partnership or syndicate referred to in that subparagraph, or

(D) an amount that, by virtue of subparagraph 66.1(6)(a)(v) of the Act, was a Canadian exploration expense, if such amount was an expense referred to in clause (A) or (B) that the taxpayer incurred pursuant to an agreement referred to in that subparagraph,

exceeds

- (ii) the taxpayer's threshold amount in respect of the well, as determined under subsection (3), minus the amount that would be determined under subparagraph (i) in respect of the taxpayer for the well if the reference therein to "after March, 1977 and before April, 1980" were read as "after June, 1976 and before April, 1977",

minus

- (b) all amounts deducted by the taxpayer under subsection (1) in computing his income for taxation years ending before the particular time.

(3) For the purposes of subparagraph (2)(a)(ii), a taxpayer's "threshold amount" in respect of an oil or gas well means

(a) where the taxpayer and one or more other persons have filed an agreement with the Minister in prescribed form in respect of the well and

- (i) the amount allocated to each such person in the agreement does not exceed the amount that would be determined, at the time the agreement is filed, under subparagraph (2)(a)(i) in respect of that person for the well, if the reference in that subparagraph to "March, 1977" were read as "June, 1976", and

(ii) the aggregate of the amounts allocated by the agreement is \$5,000,000,

the amount allocated to the taxpayer in the agreement, but if no amount is allocated to the taxpayer in the agreement, nil;

(b) where such an agreement has been filed in respect of the well by one or more persons other than the taxpayer, nil; or

(c) where no such agreement has been filed in respect of the well, \$5,000,000.

APPENDIX D (continued)

FRONTIER EXPLORATION ALLOWANCES

(4) Where as a result of mechanical or geological difficulties the drilling of a particular oil or gas well does not achieve its stated geological objectives under the drilling authority issued by the relevant government body and a further well, including a relief well, is drilled on the same geological formation and may reasonably be regarded as a continuation of or a substitution for the particular oil or gas well, the expenses in respect of the drilling of the further well shall, for the purposes of this section, be deemed to be expenses in respect of the drilling of the particular oil or gas well.

(5) For the purposes of this section,

(a) when a shareholder corporation is deemed to have incurred a Canadian exploration expense by virtue of an election made by a joint exploration corporation pursuant to subsection 66(10.1) of the Act, that expense shall be deemed to have been incurred by the shareholder corporation at the time when it was incurred by the joint exploration corporation; and

(b) when a member or a partner of an association, partnership or syndicate is deemed to have incurred a Canadian exploration expense by virtue of subparagraph 66.1(6)(a)(iv) of the Act, that expense shall be deemed to have been incurred by the member or partner, as the case may be, at the time when it was incurred by the association, partnership or syndicate, as the case may be.

(6) For greater certainty, for the purposes of this section, the term "oil or gas well" shall include any probe drilled for the purpose of determining the existence, location, extent or quality of an accumulation of petroleum or natural gas, other than a mineral resource.

[S. 1207 added by P.C. 1977-2471, August 31, 1977, *Canada Gazette*, Part II, September 28, 1977, effective for taxation years ending after March 1977.]

(7) Where a corporation (in this subsection referred to as the "successor corporation") has, at any time (in this subsection referred to as the "time of acquisition") after March 31, 1977, and in a taxation year (in this subsection referred to as the "acquisition year"), acquired, by purchase or otherwise (including an acquisition as a result of an amalgamation described in section 87 of the Act), from another corporation (in this subsection referred to as the "predecessor corporation") all or substantially all of the property of the predecessor corporation used by it in carrying on in Canada such of the businesses described in any of subparagraphs 66(15)(h)(i) to (vii) of the Act as were carried on by it, the following rules apply:

(a) for the purpose of computing the frontier exploration base of the successor corporation as of any time after the time of acquisition, there shall be added to the amount otherwise determined under paragraph (2)(a) in respect of that corporation as of that time, the amount determined under paragraph (b); and

(b) for the purpose of computing the frontier exploration base of the predecessor corporation as of any time after the acquisition year, there shall be added to the amount otherwise determined under paragraph (2)(b) in respect of that corporation as of that time, the amount, if any, by which

(i) the frontier exploration base of the predecessor corporation immediately before the time of acquisition

exceeds

(ii) the amount, if any, deducted under subsection (1) in computing the income of the predecessor corporation for the acquisition year.

[Subsec. 1207(7) added by s. 7 of P.C. 1978-1849, June 8, 1978, *Canada Gazette*, Part II, June 28, 1978, applicable to taxation years ending after March 1977.]