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THE UNIVERSITY OF ALBERTA

EFFECT OF PUBLIC POLICY ON THE SUPPLY OF PETROLEUM IN ALBERTA

BY

ABHA BHARGAVA

A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES AND RESEARCH

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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies and Research for acceptance, a thesis entitled, "The Effects of Public Policy on the Supply of Petroleum in Alberta" submitted by Mrs. Abha Bhargava in partial fulfilment of the requirements for the degree of Doctor of Philosophy.

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DEDICATIONS

To my late beloved grandmother, in whom I had my toughest critic, most valuable mentor, and an inspiring friend, and for whom I was a 'little soldier' out to win battles as well as wars with ingenuity, integrity, optimism and perseverance.

ABSTRACT

The present study formulates and estimates a micro, partial equilibrium model of the petroleum industry in Western Canada. An oil and gas firm is assumed to maximize the present value of a stream of future anticipated profits - subject to a Constant Elasticity of Transformation production function and the two capital flow constraints. The process of maximization yields estimating equations for exploration, development and production of oil and gas. An alternative partial exploration sub-model is also formulated which seeks to explain exploratory activity more in terms of the unique institutional structure of the oil and gas industry. In both models, the role of the government is analyzed through inclusion of various public policy parameters which either impinge directly on activity through production regulations or indirectly through prices and cost. The models developed are useful policy tools for analyzing the effect of past policies on levels of activity in the petroleum industry and to choose between the alternative policy proposals to achieve the policy objectives.

Both models are estimated with aggregated and disaggregated data drawn from Alberta's petroleum industry. The estimation period is

1960-1979. The models perform better for the aggregated data, although the models are successful in distinguishing between behavioral relationships underlying the various types of fields. The results suggest that the same government policies or regulatory mechanisms could impact differently on the activity decisions of the various fields.

The results also suggest high elasticities of exploration and development activity with respect to net prices of both oil and gas and therefore stress the effectiveness of royalty rates and wellhead prices as important policy tools. Production is, however, marginally sensitive to changes in prices and costs and highly sensitive to markets and the level of established reserves.

In the later part of the study, results from the model are used to conduct sensitivity and forecasting analyses to measure the effect of alternative policy proposals. The effect on exploration, development, and production, as well as the revenue sharing between the industry and the two levels of government is analyzed.

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CHAPTER I: INTRODUCTION

The purpose of this study is to formulate and estimate a comprehensive model of investment in the petroleum industry. Investment in the petroleum industry includes expenditures in the three primary phases of the industry: exploration - which involves activities directed towards finding oil and gas, and consists of geological or geophysical methods and exploratory drilling; development - which entails the establishment of productive capacity, including additional drilling and installation of facilities for the extraction of crude; and production or lifting - involving expenditures for field production, gathering, separation and holding. A present value profit function is specified in the model which takes into account all three forms of investment outlays and hence is maximized over all three phases of activity, over the life of the petroleum resource.

The investment functions for each of the three phases, exploration, development and extraction are first specified, and then the elasticities of activity response with respect to the specified financial and non-financial variables are estimated. An alternative sub-model of exploration activity only, is also formulated and estimated. This model differs from the first in that its estimating equations are not explicitly derived within a profit maximization framework. The empirical estimates of the various elasticities for both models are derived through use of several alternative sets of data drawn from Alberta, the largest producer of oil and gas in Canada.

An important part of the thesis is the investigation of the role of government in the Canadian petroleum industry. The regulatory structure under which the petroleum industry operated throughout the '60s and '70s is first briefly outlined. Then, the changes introduced under the National Energy Program (NEP)[1] of 1980 and its subsequent revisions, as well as the most recent developments in the regulatory structure introduced through the Western Accord are also discussed. In comparison with most industries in Canada, the extent of government intervention in the oil and natural gas industry is substantial, and until recently (pre-Western Accord period) has increased over the years. The government's role starts with the ownership of the resource - much of the natural resources in Canada are owned directly by the provincial governments. Although government relies heavily on the private sector for the development of the resource, it exercises substantial control over the industry by setting the maximum rate at which the resource can be extracted, and until recently also the price at which the resource can be sold. The production rates are set by taking into account both the availability of markets, and the most efficient technical rates of production. Prices have been forced to diverge from world prices: in much of the '60s and early '70s, the Canadian prices of oil were kept above the price of imports at Montreal; between 1973 and June 1, 1985, the prices were set at levels considerably below the world prices. Besides regulated production and pricing, the oil and natural gas industry has also been subject to relatively higher levels of taxation from both the federal and provincial governments, although it has also received special tax incentives from the two levels of government.

Despite a relatively high degree of government presence in the petroleum industry, there have been very few attempts in the literature to model the role of government in determining the level of investment in the oil and gas industry in Canada. The present study attempts to fill this gap by formulating a model in which the ploicy parameters of government are explicitly included and analyzed in the model. The usefulness of such a model would have been demonstrated, for example, when the National Energy Program (NEP) was introduced in 1980. It was felt that the objective of self-sufficiency in oil could be achieved through curtailment in demand and an increase in supply[2]. A decrease in the growth of demand was then forecasted by several sources including those of the National Energy Board[3]. These forecasts were a result of much rigorous and sophisticated analysis involving development of detailed energy demand models[4]. Conversely, forecasts of supply were less precise and less rigorous, largely due to the lack of a mechanism for forecasting the response in investment and supply to various policy changes. This study analyzes and estimates the supply responsiveness of the industry to changes in various government regulatory measures through a rigorous analysis and derives the various supply elasticities. The model developed is an important policy tool to analyze the effect of past policies on levels of activity in the petroleum industry and, to choose between the alternative policy proposals to achieve the policy objectives.

The thesis is organized as follows: Chapter II gives a description of Alberta's oil and gas industry. It provides background information on such aspects as Alberta's position in the Canadian oil and gas industry; the structure of the industry; the revenues generated in the industry; and the federal-provincial regulatory structure including production regulations, pricing and other incentives provided to the petroleum industry.

In Chapter III a brief review of the literature on supply modelling is provided. Both the empirical and the theoretical work is examined and emphasis is given to a discussion of the supply elasticities obtained in previous studies.

Chapter IV deals with the specification of two models of investment. The first is a profit maximization model wherein firms are assumed to maximize the present value of their cash flows subject to a production function and two capital flow constraints. In this model, the estimation equations for exploration, development and production are derived from the maximization procedure. The second model is a three equation model for exploratory investment derived through an inductive approach as opposed to a deductive approach in the first model.

Chapter V deals with the estimation of the two models. After discussing the data, the results from both the principal and alternative models for the period 1960-1979, covering the entire petroleum industry in Alberta, and for 1965-1979 for certain fields and zones within Alberta are presented and analyzed. The results indicate that exploratory activity is most sensitive to the prices of oil and natural gas. The cost per foot of exploratory drilling does not affect exploratory activity significantly. Development activity is most sensitive to price of gas, the price of oil and the cost of development drilling. Production is more sensitive to market availability and the level of proved reserves. The results also indicate that once in the production phase, the level of production is not very sensitive to prices and costs. This is hardly surprising in view of tremendous sunk costs in exploration and development of the resource, and small marginal costs of production. In general, the results indicate that government programs such as the drilling incentives program, well - spacing and market demand prorationing have affected the investment levels in the oil and gas industry. The structure of these programs is such that it generates different effects on different regions of the province.

In Chapter VI, the study concentrates on sensitivity analysis with respect to selected tax rates, prices and cost assumptions. It also forecasts the supply response of exploratory and development activity and the production of oil and gas for the next two decades under various price and tax scenarios. Although the estimation period is resticted to the years before the NEP was introduced, the more recent changes are incorporated in the forecasting analysis conducted in the later half of the study. The results of this analysis indicate that the highest level of investment can be achieved through increases in the netback price of oil (achieved by either a higher wellhead price of oil or lower royalties). The model developed in this thesis can easily be linked to a revenue - sharing model to derive the relative shares of the industry and the two levels of government in the total revenue pie of the petroleum industry. Such a model is developed in this thesis and in this chapter, we derive implications for revenue - sharing between the industry and the two levels of government stemming out of alternative policy proposals. Note that the relative revenue shares have been an important point of contention in country's petroleum policy.

Finally, Chapter 7 provides a summary of the study and the principal conclusions. Appendices A, B, and C respectively give additional information concerning the source and the formulation of the data, the derivation of the model and the symbols and technical definitions used in the study, and the exhibits including questionnaires sent to the industry for the purpose of gathering data.

Footnotes:

1. Energy, Mines & Resources The National Energy Program, October 28, 1980 Ottawa; Government of Canada.

2. Other objectives defined in the NEP are as follows: (i) to provide real opportunity to all Canadians to participate in the energy industry in general, and the petroleum industry in particular and to share in the benefits of industry expansion; and (ii) to achieve fairness, with a pricing and revenue sharing regime which recognizes the needs and rights of all Canadians in a federated state of shared governmental jurisdictions.

3. The National Energy Board in 1981 forecasted that the primary demand for oil would increase at an average of 2% per year for the following two decades. This growth was considerably smaller than overall primary energy demand, principally because of the expected increase in oil prices compared with the prices of other fuels. Also, the total demand on all petroleum products was forecasted to decline at .8% per year uptil 1990, and then increase at about 1.2% per year between 1990 and 2000. (See NEB Canadian Energy Supply and Demand, 1980 - 2000, 1981 p 26)

4. Other demand models include those developed by McRae(1977), Berndt(1980), Canada Department of Energy and Mines (1979), Data Resources Inc. (1976) and Watkins (1980).

CHAPTER II: ALBERTA'S OIL AND GAS INDUSTRY

The purpose of this chapter is to provide background information on issues which are of significance to the overall study. Specifically, it provides information on the fiscal and pricing regime governing the petroleum industry including the mode of revenue sharing between the two levels of government and industry, the institutional framework under which the Alberta industry operates including the ownership of resource, the private sector's access to the resource and the rules and regulations governing this access, and the structure of the Alberta industry and its relative position in the petroleum industry of Canada. Such information is important for formulating the model and analysing the results. For example, details on taxes and royalty rates help determine the policy parameters that should enter directly into the model; information on the mode of revenue sharing between the two levels of government and the industry help in evaluating how the various policy parameters can effect industrial profitability and therefore the industry activity levels; and a discussion of special policy programs such as the incentives provided by the federal and provincial governments will later assist in a proper interpretation of the results generated from the model.

In view of the above, the chapter is divided into five sub-sections as follows: (1) Alberta and the Canadian oil and gas industry, (2) the market structure of the industry, (3) the role of government including matters of ownership, production regulation, pricing etc, (4) the revenues generated within the petroleum industry and the mode of revenue sharing, and 5) special incentives provided by the government.

1. The Canadian Oil and Gas Industry

Most of Canada's oil and gas is produced in Alberta. In 1970, 73%[1] of Canadian crude oil (both conventional and synthetic), was produced in Alberta, and by 1983 this share had increased to 81%. The Alberta share of natural gas production also increased from 81% in 1970 to 88% in 1983. Saskatchewan and British Columbia also produce these products but not in substantial amounts. In 1983, the Saskatchewan share of oil production was 14% and of natural gas 2%, and British Columbia's respective shares were 3% and 9%.

Alberta oil is consumed in the Prairies, the Northwest Territories, Ontario, B.C., the United States and more recently in Quebec. Table 2-1 indicates each area's share in the consumption of the total Alberta production of crude oil and natural gas.

Oil is consumed primarily by the transportation sector whereas natural gas is consumed primarily by the industrial and residential sectors. For example, in Ontario in 1983,[2] the transportation sector accounted for half of the petroleum products consumed in that province and 3% of natural gas. The industrial sector accounted for 6% of petroleum products and 36% of natural gas and the residential sector for 5.7% of petroleum products and 28% of gas.

Table 2-1

Disposition of Alberta Oil and Gas Production (1983)

	OIL	GAS
Exports	16.03%	31.27%
Alberta	21.52%	24.15%
Ontario	33.40%	29.94%
Saskatchewan and Manitoba	3.56%	6.04%
B.C.	8.15%	.44%
Quebec and Maritimes	17.33%	6.23%
	100%	100%

Source: AERCB, Alberta Oil and Gas Industry Annual Statistics, AERCBST 84-17, 1983

Imports of crude oil and equivalent increased throughout the '60s and peaked at 52.1 million cubic metres in 1973.[3] Since then they have been decreasing, and in 1983 amounted to 14.4 million cubic metres. Similar trends have been observed in exports of crude oil and equivalent. Exports, which had been increasing throughout the '60s, peaked in 1973 at 66.8 million cubic metres. By 1981 exports of crude oil and equivalent were down to 9.5 million cubic metres but started to increase in 1982 and 1983 to 12.16 million m^3 and 16.778 million m^3 respectively. While exports and imports both declined in the '70s, the absolute decline in exports exceeded the declining in imports. In 1981 and 1982, Canada was a net importer of oil, although the pattern reversed in 1983.

Exports of natural gas during the last decade have increased periodically while remaining constant at other times, with a total range of around 707 - 1031 billion cubic feet (bcf). Imports of natural gas peaked in 1968 at 88.25 bcf and have declined since. In 1983, imports of natural gas were quite marginal amounting to .039 bcf in 1981[4].

2. Structure of the Oil and Gas Industry

The products of the industry are crude oil, natural gas, natural gas liquids and sulphur. According to recent calculations,[5] there were approximately 600 firms which were involved in producing one or more of the above products. In 1974, the largest producer of natural gas accounted for some 10% of total Canadian production, the top 10 producers for 62% and the top 20 for 75%. For oil, the figures were 17%, 67% and 85% respectively[6].

The upstream segment of the petroleum industry is involved in three broad activities: 1) exploration, 2) development and 3) production. The junior oil and gas producers play a more significant role in the development and production phase than in exploration[7]. In 1983, the junior oil and gas producers accounted for approximately 17.5% of exploration expenditures, 40% of development expenditures and 26.4% of production expenditures[8]. The respective shares of the senior oil and gas producers were 50%, 37% and 32%. The integrated companies accounted for the remaining exploration, development and production expenditures.

Much of the Canadian oil and gas industry is owned and controlled by foreigners, although over the years foreign control has decreased. Of total assets held in the petroleum industry in 1983, 48% were owned and 46% were controlled by foreigners, as compared to 62% and 59% respectively in 1980. The share of foreign firms in exploration expenditures has also declined from 67% (owned) and 65% (controlled) in 1980 to 38% (owned) and 35% (controlled) in 1983. However, the share of foreign firms in the upstream revenues is much higher. In 1983, 59% and 62% of total upstream revenues were respectively accounted for by foreign owned and controlled firms as compared with

72% and 78% in 1980. Foreign firms also hold a substantial share in oil sands operations in Canada, amounting to 77%.

As a result of a high level of foreign ownership and control, there have been large outflows of funds from Canada. In 1983, 65% of total dividends paid by the industry were to foreign companies amounting to 49% of net income generated in the industry in that year. The reinvestment ratios[9] for the foreign firms have been lower than for the Canadian firms. In 1983, the ratio for the total industry operations for foreign controlled firms was 92% and for Canadian controlled firms it was 138%. The ratios for upstream expenditures were 66% and 132% respectively.

3. The Alberta Government's Role in the Oil and Gas Industry

The ownership of natural resources in Canada is shared between the provincial and federal governments. The 1930 amendment of section 109 of the British North America Act gave the Western provinces the ownership of natural resources located within their respective jurisdictions. Rights to the extraction of petroleum and natural gas over approximately 85% of the lands in the Province of Alberta are now held, owned and disposed of by the Government of Alberta, the remaining 15% having been alienated previously to private freehold, or retained over certain Federal lands within the province[10]. The provincial government has exercised responsibility for the management and sale of oil and natural gas within the province, but the federal government is empowered to exercise important controls over interprovincial trade and commerce, interprovincial pipelines and certain types of taxation. The federal government may thus possess ultimate control over the marketing of all of Alberta oil and gas production destined for points outside the provincial boundaries.

In this sub-section we first discuss the controls administered by the provincial government relating to a system of resource access for the private sector and then to production of the resource. Later we also discuss the federal-provincial controls over oil and gas pricing. All three types of controls enter directly or indirectly into the models developed and estimated in the study. Prices of both oil and gas are explanatory variables in both models; the production regulations through a market demand prorationing variable are included in one of the models; and the acquisition of land is included in another model. We extend our discussion of resource acquisition to include the differences in regulation for various zones. Note that the two models developed in this study are empirically tested for these zones.

(i) Acquisition of Resource[11]: Although the government of Alberta holds title to some 85% of the oil and gas rights within the province, it relies heavily on the private sector for the actual exploration, development and production of the resource. Prior to the 1976 amendment to the Mines and Minerals Act, there existed a system of

Petroleum and Natural Gas Reservations and Permits, Crown Reserve Drilling Reservations, and Natural Gas Leases and Licences through which the private sector obtained an access to the resource. The permits and reservations conveyed the right to drill for petroleum and natural gas where the mineral rights reside with the crown, and also to produce the same, subject to any exceptions expressed in the permit or reservation. A lease conveyed the right to produce. In order to produce, an applicant could later select for lease an area of not more than 50% of the total area held under a petroleum and natural gas reservation. However, the locations or concentrations of such leased areas had to form a checkerboard pattern, or otherwise had to be at a distance of not less than 1.6 kilometres from the nearest block of additional acreage selected under the same lease arrangement.

The amending Act of 1976 made provision for the continuation of then existing reservations, permits, drilling reservations and crown reserves gas licences and petroleum and natural gas leases until their terms expire or until such time as the holder requests cancellation. However, the old system of land tenure was replaced by Petroleum and Natural Gas Licences and Petroleum and Natural Gas Leases. The former replace the Petroleum and Natural Gas (P & NG) Reservations, P & NG Permits, Crown Reserve Drilling Reservations and Natural Gas Licences and the latter are the continuation of earlier P & NG leases. A licence confers the right to drill and is generally applicable to exploration, while a lease as discussed below gives the right to produce. A person wanting to acquire a licence covering certain lands directs a request to the Minister, who then advertises the licence for sale by public tender or refuses to offer the licence for public disposal. Once the licence is offered, a person obtains the licence if his bid at the sale is accepted. In a case where the government feels that the bid is not appropriate, it may refuse a licence. The offer to bid is accompanied by a fee of $500, and the rental for the first year is set at $1 per year per acre.

The duration of the licence can vary according to its location. In recognition of the varied nature of the geology and accessibility of lands to be licensed, the Government of Alberta has divided the province into three distinct geologic and geographic areas: the Plains area, the Northern area and the Foothills area. Note again that the models developed in this study are estimated separately for each of these zones. The term of a Plains licence is two years. Northern and Foothills licences have four-year and five-year terms respectively. A Plains area licence may be extended for a maximum of one year and Northern and Foothills licences may be extended for 60 days. The maximum area that may be acquired under an exploratory licence is 29 sections in the Plains area, 32 sections in the Northern area and 36 sections in the Foothills area. By differentiating between these areas the government implicitly provides incentives to explore in specific zones. After the licensee has drilled a well, he is entitled to apply for a lease covering rights to the production of petroleum and natural gas in lands contained within the licence area. The maximum number of sections that may be included in an application for a lease under a petroleum and natural gas licence depends upon the depth of the lease-earning well. The minimum size of a Petroleum and Natural Gas lease is typically a quarter section, which is now the normal spacing unit for an oil well in Alberta.

The earlier P & NG leases were of 10 years term. P & NG leases acquired <u>after</u> July 1, 1976, either by application or at a sale by public tender, have a term of five years. An application for a lease must be accompanied by the prescribed rental of $1 per acre in advance, together with the application fee of $50. During its initial term, a five year lease conveys to the lessee the Crown's rights to produce petroleum and natural gas in all stratigraphic zones. Upon expiry of the initial term of five years, the lease conveys the rights to produce below the initial production zone, down to the base of the deepest stratigraphic zone in the leased area containing petroleum or natural gas. This provision may have encouraged deeper drilling.

<u>(ii) Production Regulation</u>. Once the licence has been granted the government determines the drilling spacing unit and later the production spacing unit. The drilling spacing unit for a well is defined as the surface area and the sub-surface vertically beneath that area. The normal drilling spacing units under an exploration licence differ for oil and gas - for an oil well it is one quarter section while for a gas well the normal spacing unit is one section. The production spacing unit may consist of one or more drilling

spacing units. The production spacing units are not mandatory. They are sought by the producers to reduce operating costs by producing from the most efficient wells out of a total of two to three wells. A producer may choose to utilize the provision of production spacing units before drilling wells. In that case, he may drill one well on a tract that has lease for 2 or more wells, and produce the allowable for all these wells from one well. The maximum amount of land that can be held under the production spacing unit is 2 1/4 sections. The production spacing units are generally non - operative for gas. For oil, once the well has been drilled in accordance with the above regulations the lessee may produce from his well, but only at rates in accordance with the existing market demand order of the Energy Resources Conservation Board. Once the market demand prorationing (MDP) rates are determined, the production is further subject to a maximum efficiency rate (MER) which is determined purely by technological considerations. Thus, the actual production rate for each well is the lesser of MDP or MER. Note that there are no significant market demand prorationing restrictions for gas. Only 1% of gas wells are subject to such restrictions. Also, there are no maximum efficiency rates set up for gas except for pools which have apparent water problems.

<u>(iii) Oil and Gas Pricing</u>. Historically, prices of both oil and gas have been subject to government regulation. However, as a result of the Western Accord, the price of oil has recently been de-regulated effective June 1, 1985. Also, effective November 1, 1986, the price

of natural gas will be de-regulated. In this section we discuss the historical trends in both oil and gas prices.

(a) Oil prices. After the discovery of Leduc in 1947, it became important in order to expand the market for Canadian crude, that its price be kept competitive with imported sources of supply at the market fringe. Therefore, the Alberta wellhead price was first reduced in December, 1948 to make it competitive with the delivered price in Manitoba and then, further reduced in 1951 to make it competitive at Sarnia with the delivered price of Illinois crude. Between 1951 and March 1959, Sarnia in Ontario served as the market equalization point for competing sources of supply. The Alberta wellhead price in this period was essentially determined by deducting the transportation cost from a competitive price, and making some adjustment for quality differential.

In 1961, the introduction of the Canadian National Oil Policy reserved markets to the west of the Ottawa River line for domestic crude[12]. During this period exports to the United States increased, although subject to the quotas set under the United States Oil Import Policy (USOIP). Sarnia was replaced as the market equalization point by the Detroit-Toledo area. The U.S. prices under the USOIP were insulated from the world oil prices and remained at a higher level. Due to our own policy and the effect of USOIP, the domestic prices in Canada were kept at a higher level than world prices[13]. By the early '70s, however, the domestic price again coincided with the external price of alternative import supplies. Through the years following the oil embargo of 1973 until May 31, 1985, Canadian wellhead prices were held at levels below average world prices. Since June 1, 1985 the price of oil has been de-regulated.

Although the average price of domestic crude oil was held at levels below the average world prices from late 1973 to mid 1985, a system of differentiated pricing was followed since the introduction of the NEP in 1980. (Note that prices have always varied by quality, but now the prices varied according to the timing of discovery, the method of recovery, and the area of production).

The NEP introduced a new dimension to the pricing of oil: conventional oil at the wellhead was to be fixed at $14.75; the oil sand (synthetic crude) reference price at the wellhead was fixed at $38 per barrel in January 1981; and finally, tertiary (enhanced) recovery oil at the wellhead was fixed at $30.00 per barrel. All three prices were then to increase over time at pre-set rates. The price of gas, which had increased by about 15¢ per thousand cubic foot (Mcf) for every $1.00 increase in the wellhead price of oil since 1975, was to increase at 45¢ per Mcf per year.

Following the 1981 revision of the NEP, the three tier price system was replaced by a two tier system of prices. The price of old conventional oil was increased to $21.25 in October 1981, to $23.50 on January 1, 1982 and to $25.75 on July 1, 1982. After that date, it increased by $4.00 every six months subject to a ceiling of 75% of the international price. The second set of prices was applicable to new conventional oil, to incremental oil and to synthetic oil. New conventional oil was defined as oil from wells discovered after December 31, 1980. This set of prices, called the New Oil Reference Price (NORP) was set at the international price level.

Further modifications were made in the domestic pricing structure in the summer of 1982. In the NEP update of 1982, a third category of oil price called the Special Old Oil Price (SOOP) was introduced for oil discovered after 1973 but prior to December 31, 1980. This was the oil which was not in receipt of NORP but qualified for 'New' oil royalty rates. The price of this oil was set at 75% of the international price effective July 1, 1982. Between July, 1983 and June 1, 1985 SOOP was raised to NORP under the 1983 energy pricing agreement.

<u>(b) Natural Gas prices</u>. The discovery of oil in 1947 was followed by the discovery of both associated and non-associated gas and a subsequent accumulation of natural gas reserves in enormous amounts[14]. To reduce the excess reserves of natural gas, the Alberta government under the Gas Reserves Preservation Act (1950) allowed the exports of 'surplus' gas from the province, 'surplus' initially being defined as the difference between known reserves and Alberta's forecast of cumulative gas requirements over a 30 year period. Following this act, exports of natural gas increased

tremendously. This gas was sold under long term contracts by three major gas trunklines - the TransCanada Pipeline system, the Alberta and Southern system and the WestCoast system. These long term contracts generated fairly stable prices.

During the '50s and '60s, the wellhead price of gas in Alberta was determined through negotiated contracts in which prices were fairly constant except for minor escalations and periodic re-determinations. The price of gas under this system was approximately 9.3¢ per Mcf in the '50s, 12¢ per Mcf in 1961 and 16.5¢ per Mcf in 1970.

In the early '70s, the National Energy Board (NEB) refused any additional exports to the United States. The closure of these export markets greatly impeded competition in the natural gas industry, with large buying power being concentrated with Trans Canada Pipelines in many areas of the province. In 1972, an investigation into the field price of natural gas was conducted by the AERCB at the request of the Government of Alberta[15]. The report recommended that natural gas purchase contracts should include a base price, which in 1972 was to be 26¢ to 36¢ per Mcf. This report also recommended the inclusion of a clause requiring price re-determination at least every 5 years. Following this report, the Government of Alberta introduced the Arbitration Amendment Act in 1973,[16] which set the guidelines for Arbitration. Under these guidelines, the price of gas was equated to its "commodity value". "Commodity value" was to be technically defined as " the thermal value of gas determined by reference to the volume-weighted average prices of substitutable energy sources competing with gas for the various end uses of gas in the consuming markets served, directly or through exchange, by the buyer of gas under a gas purchase contract"[17].

In 1975, the Natural Gas Pricing Amendment Act (NGPAA), was introduced. This legislation tied the natural gas price to .85 of the BTU equivalent of the oil price in Toronto[18]. Thus, in 1975 in accordance with NGPAA the Toronto City Gate price was set at $1.25 per Mcf[19]. The export price of gas at this time was set at $1.60 per Mcf. The NGPAA of 1975 was superseded by the legislation introduced under the federal NEP in 1980[20] in which the price of gas was to be set as .65 of the BTU equivalent oil price at Toronto City Gate. The adjustment from the previous level to the .65 level was to take place over a three year period, i.e. until 1983. In the most recent developments, the price of natural gas is to be de-regulated effective November 1, 1986[21].

4. Revenue Sharing

The revenues generated within the oil and gas industry are shared by the two levels of government, federal and provincial, and the industry. The provincial government's revenues comes from royalties, the provincial corporate income tax and from land payments of various kinds. Prior to 1980, the federal government's share consisted only of the corporate income tax, but since the introduction of the NEP in 1980 and its subsequent revisions, the Petroleum and Gas Revenue Tax (PGRT), Natural Gas and Gas Liquids Tax (NGGLT) and the Incremental Oil Revenue Tax (IORT)[22] have also contributed to the federal share.

(i) Revenue Share of the Provincial Government. The petroleum royalty regulations[23] determine the amount of royalty payable to the provincial government for petroleum and natural gas produced under provincial leases. The royalty rates for oil are determined on a sliding scale basis and depend upon the volume of production, the price received for the oil and the timing of the discovery[24]. Further, oil production from certain operations, such as experimental tertiary oil recovery projects and the production of synthetic oil are subject to special royalty rates. Oil produced from pools discovered since April 1, 1974 is termed as "new" oil and is subject to new oil royalty rates which for a reference well is 35% (marginal rate). Oil from pools discovered on or before March 31, 1974 is called "old" oil for royalty purposes and the marginal rate for a reference well producing old oil is 45%. The rates have recently been reduced by the introduction of the new Oil and Gas Incentive Program in 1985. The royalty rates will be decreased by a total of 5 percentage points for both categories of oil over a two year period.

Like oil, natural gas royalty rates are also different for new and old gas. "New" gas is defined as gas discovered after 1973 and "old" gas as discovered prior to 1974. The gas royalty depends on price and not on volume of production except on wells producing less than 16,900 m^3/d. For old gas, the marginal rate is 45% of price in excess of \$17.75 per thousand m^3 and for new gas, the rate is 35%. Under the new oil and gas incentives program in 1985, the natural gas royalty rates are to be reduced by a total of 5 percentage points over two years.

The provincial corporate income tax is calculated on taxable income determined in the same manner as for federal income tax purposes with one exception: royalties are deductible for the provincial corporate income tax. Since 1974, royalties are non-deductible in federal corporate income tax calculations. However, the non-deductibility of royalties is compensated to some extent by the introduction of a resource allowance deduction. The resource allowance is only 25% of resource profits, which may be substantially less than the royalties.

Provincial revenues derived from land payments consist of fees, rentals and above all land bonuses paid for various leases and licences. It should be noted that in order to obtain a lease or a licence initially the operators have to bid for the rights conferred. In case where a licence is later converted to lease, no bidding is required.

<u>(ii) Revenue Share of the Federal Government</u>. The basic rate of federal income tax applicable to a corporation in the resource

industry is 46%[25]. The effective rate is considerably lower, however, due to various deductions and writeoff provisions. First, like all Canadian corporations, oil and gas corporations may deduct, as part of the Federal Tax Abatement, from their federal tax otherwise payable an amount equal to 10% of the corporation's taxable income said to be earned within the province. (Income Tax Act, Section 124). This provision is to compensate the corporations for provincial corporate income tax. Second, additional writeoff allowances such as the following are provided to the mining industry (including petroleum) by the federal government in the calculation of taxable income:

<u>(a) Exploration and Development Expense Write-offs</u>. Cost and expenses incurred by a taxpayer in exploring for minerals in a given tax year, and in bringing in these deposits of minerals to a point of commercial production are deductible against income generated from the sale of these minerals in that year. If expenditures which qualify as exploration and development expenses exceed an amount of net income available for deduction, they can be deferred and carried forward to subsequent years until sufficient income has been generated to offset the expense. Prior to 1974, firms could deduct 100% of their exploration and development expenses in the year of outlay. Since 1974, although the exploration expenditures can be deducted to a full 100%, only 30% of the development expenses can be deducted in the year of outlay when calculating taxable income for that year. The rest can be deducted on a declining balance at a rate of 30%. Further,

separate rates exist for deducting the expenses related to the acquisition of oil and gas property rights (Canadian Oil and Gas Property Expense). All above writeoff rates are limited to those expenditures made within the boundaries of Canada.

(b) Depletion Allowance. Prior to the introduction of the NEP, a special deduction in the form of a depletion allowance was allowed to tax payers who had profits from producing resources and had expended money to accumulate an earned depletion base. Prior to May 6, 1974[26] the depletion allowance was equal to the earned depletion base but effective May 7, 1974 the depletion allowance was changed to the lesser of (1) 25% of "resource profits" for that year or (2) "earned depletion base" as of the end of the year. The term "resource profits" means the taxpayer's net income (before royalties paid or payable) on production from (1) the dispositions of Canadian resource properties; (2) the production of oil or gas or minerals (up to their prime metal or equivalent stage), provided the taxpayer is an operator or deemed operator; (3) processing mineral ores to their prime metal or equivalent stage; and (4) royalty income in respect of resource production.

The "earned depletion" base is one-third of the sum of qualifying expenditures made by the taxpayer since November 7, 1969. In general, expenses for the exploring and developing of properties (but not including the acquisition cost of a resource property - for example, land costs, bonus bids, etc.) qualified for the earned depletion base. A special incentive was granted to the taxpayer exploring for oil and gas in Canada's frontier and offshore regions. In these areas, expenses incurred between March 31, 1977 and April 1, 1980 in drilling an exploratory well were to earn a special depletion base of $2 for each $3 of expenditure incurred in excess of $5 million. Beginning April 10, 1978, the Government of Canada also provided a special earned depletion base of $1 for each $2 expended for enhanced oil recovery.

Through the exploration expenditures write-off and the depletion allowance, where profits are available, the operators could write-off 4/3 of their exploratory outlays (100% through exploration expenditure write-off provision and 33 1/3% through depletion allowance), 3/2 of enhanced operations, and 5/3 of frontier operations beyond an initial $5 million outlay. Since the introduction of NEP, the depletion allowance has been phased-out gradually starting in 1982 until a zero depletion allowance was reached in 1984. However, the depletion allowance on integrated oil sands projects, enhanced recovery projects, and heavy crude oil upgrading still continues.

<u>(c) Resource Allowance</u>. For the 1976 and subsequent taxation years all taxpayers are entitled to deduct 25% of their "resource profits" for the year in computing income . Resource profits for this purpose are similar but not identical to resource profits for depletion purposes. For resource allowance purposes, resource profits are calculated before any deduction for exploration, development, or

interest expense, but after deducting operating expenses, including capital cost allowance on mining buildings, machinery and equipment. As stated earlier, the introduction of the resource allowance compensates partly for the non-deductibility of royalties in the calculation of federal corporate income tax.

<u>(d) Capital Cost Allowance</u>. The mining industry is entitled to a capital cost allowance of up to 30% on all depreciable assets (mining buildings, machinery and equipment).

The National Energy Program of Oct, 1980 introduced some changes in the Federal tax regime. First, the earned depletion allowance was phased-out altogether. The rates were 33 1/3% of exploration and development expenses for 1981, 20% in 1982, 10% in 1983 and 0% thereafter. Second, a petroleum and natural gas revenue tax was introduced. Third, an incremental oil revenue tax was levied on incremental oil revenue at a rate of 50%. This last change was introduced in September, 1981. For a detailed analysis of these changes the reader is referred to Section 3 of chapter VI.

In the most recent developments, an agreement of understanding on energy pricing and taxation was reached between the Federal government and the three producing provinces. This agreement, generally referred to as the Western Accord, makes the following changes. First, the crude oil prices were de-regulated effective June 1, 1985. Second, the PGRT was eliminated for new wells drilled after April 1,

1985. For existing wells, the PGRT was to be phased-out gradually. Third, taxes such as IORT, NGGLT were eliminated effective June 1, 1985. Fourth, as stated below, Petroleum Incentives Program (PIP) will be eliminated on March 31, 1986.

5. Special Incentives Provided to the Oil and Gas Industry

In addition to the special writeoff allowances, special incentives in terms of cash credits are provided by both levels of government.

(i) Federal Incentives. These consist primarily of the Petroleum Incentives Program (PIP) payments. In order to compensate partially for the phasing-out of the depletion allowance and also to provide incentives for Canadian ownership in the industry, the Federal government in the National Energy Program introduced the Petroleum Incentives Program which provided certain special incentives through cash payments for oil and gas exploration and development. Under this program, companies that are at least 50% Canadian owned, are given an incentive payment of 10% of approved exploration costs and 10% of approved development costs incurred in 1982 and thereafter[27]. For exploration, the rate increases to 15% after 1983. For similar expenditures, firms with 75% Canadian ownership are provided an incentive payment of 35% of approved exploration cost and 20% of approved development costs incurred in 1981 and thereafter. For exploration on Canada Lands, the firms are provided additional incentive payments to those discussed above. For firms which are 50%

Canadian controlled and owned, there is an additional incentive payment of 10% of approved exploration costs. For firms which are at least 75% Canadian owned and controlled the additional incentive payment is 20%.

As part of the special 1981 agreement with the province of Alberta, the Alberta government administers and pays the petroleum incentive grants applicable to the projects undertaken within the province. Following the Western Accord, The PIP would be eliminated on March 31, 1986.

<u>(ii) Provincial Incentives</u>. In addition to the above federal incentives, the government of Alberta provides some direct incentives to the petroleum industry. Between 1968 and 1971 both exploratory and seismic activity dropped considerably and a movement of activity away from Alberta was observed. In order to curb this migration and to re-stimulate such activity in the petroleum industry, the provincial government introduced

(a) an exploratory drilling incentives program, and
(b) a geophysical incentives program.

<u>(a) Exploratory drilling incentives program</u>: This was initiated by the Exploratory Drilling Incentive Act of August 1, 1972[28]. The objective of this Act was to encourage high-risk exploratory drilling and to increase the drilling activity in remote locations at a time

when this type of drilling was declining in the province. During the period of August 1972 - December 1973, the incentive program related only to new field wildcats, and a credit in dollars was given according to the following formula:

$$\text{Credit (in \$)} = 45 + \frac{(\text{Depth})^2}{1350}$$

This credit could be used to pay provincial taxes, royalties, bonuses, fees etc. Also, an exemption from the payment of crown royalties and taxation on freehold production for a period of five years from the time the well commenced production was granted.

Since 1974 this program has been modified. A well is now certified as an incentive exploratory well if (a) it is located more than three miles from a completed well or (b) located less than three miles from a completed well but expected to be drilled significantly deeper than the completed well. (There is no pre-specified definition of what can be considered as significantly deeper). The amount of credit that a particular company can apply for, depends on whether it comes under the class "A" or class "B" footage. The well receives class "A" footage if there are no abandoned wells within a mile and a half radius of the proposed well, and class "B" footage otherwise.

To take into consideration the differing cost structures between various regions in Alberta, the provincial government has divided the province into four drilling incentive regions, and the credit given to firms depends, among other things, on the region in which the well is located. These drilling incentive regions are the Plains, Central, Northern and Foothills areas. A certification of a well as an incentive exploratory well lapses thirty days after the date of the certification unless the well has been spudded. However, the certification can be renewed.

<u>(b) Geophysical Incentives Program</u>. The geophysical incentives program came into effect on February 11, 1975 and provides for the establishment of a credit for expenditures incurred in seismic operations. The credit so obtained can be used to defray any cash obligations payable to the province from oil and gas. The amount of credit depends upon the location of the seismic activity. For this purpose, the province has been divided into three distinct geographic regions, comprising the Foothills area, the Green area and the Yellow-Plains area. Such a division takes into account the accessibility of the area and the relative costs associated with the seismic survey.

All geological information on the basis of which credit is granted is kept confidential for 3 years, after which it is available to the public for a period of 5 years at a charge not exceeding 60% of the credit established for the survey. The credit in dollars for the geophysical incentives program is determined in accordance with the following formula:

credit ($) = 500 k.m.

where k is the incentive factor for the area of Alberta in which the geophysical program was conducted, and m is the number of miles of minimum fourfold sub-surface coverage in that area. For various regions, the values of k are:

(i) 1 for the Yellow and Plains area

(ii) 2 for the Green area and

(iii) 3 for the Foothills area.

Both the exploration incentives program and the geophysical incentives program were eliminated in the June 24, 1985 announcement on Oil and Gas Incentives by the Government of Alberta. Effective July 31, 1985 the two incentives were replaced by a system of reduced oil and gas basic royalty rates, a new crude oil royalty holiday program and the natural gas royalty holiday program.

Footnotes:

1. Source: Canadian Petroleum Association, Annual Statistics, 1984

2. Statistics Canada, Quarterly Report on Energy Supply - Demand in Canada, 57 - 003, 1983 Quarter 4

3. Canadian Petroleum Association, Annual Statistics, 1982.

4. Ibid.

5. Source: Canadian Oil Register, (1980 - 1981).

6. Watkins, G.C. (1977).

7. The definition of junior, senior and integrated companies corresponds to the definition used in Petroleum Monitoring Agency Reports. Junior producers are companies that individually generate less than 15% of industry upstream revenues. Senior producers are companies companies that individually generate more than 15% of

industry upstream revenues. Integrated companies are those that have significant revenues in both the upstream and downstream revenues.

8. The data provided in the remaining part of this sub-section are obtained from the Petroleum Monitoring Agency Canadian Petroleum Industry Monitoring Survey, 1981 and 1984.

9. The reinvestment ratio is calculated as ratio of capital expenditures to initial cashflow.

10. Crommelin, M., Pearse, P.H. and Scott, A.(1978)

11. Much of the information discussed in this sub-section is obtained from Alberta Energy and Natural Resources, Minerals Disposition Division, Oil & Gas Tenure Legislation and Practice in the Province of Alberta, Canada, Internal Document, April 1977.

12. Watkins, G.C. (1977).

13. Ibid

14. Ibid.

15. AERCB (1972).

16. Statutes of Alberta. The Arbitration Amendment Act, 1973. Chapter, 88.

17. AERCB (1972).

18. Statutes of Alberta, The Natural Gas Pricing Agreement Act, 1975. Chapter 38.

19. Watkins, G.C. (1977).

20. Department of Energy, Mines and Resources, (1980).

21. Agreement on Natural Gas Prices and Markets, Oct 31, 1985 between Governments of Canada, Alberta, B.C. and Saskatchewan.

22. Note IORT was only effective from January 1, 1982 to May 31, 1982.

23. Alberta Energy and Natural Resources, Energy Statutes and Regulations, p 117-10.

24. Price Waterhouse, (1984).

25. Ibid.

26. M.J. Gungl and A.M. Pilling _Federal and Provincial Taxation of the Mining Industry_, Coopers and Lybrand 1980.

27. Price Waterhouse, (1984).

28. Alberta Energy and Natural Resources, _Energy Statutes and Regulations_.

CHAPTER III: REVIEW OF THE SUPPLY MODELLING LITERATURE

The purpose of this chapter is to summarize briefly the developments in the literature in the area of petroleum/resource supply. The chapter is divided into two parts: the first examines the theoretical developments in supply modelling of an exhaustible resource. The second deals with empirical applications of the supply models developed in this area.

1. Review of Theoretical Literature

The theory of exhaustible resource use or extraction was first formally stated in the articles by Gray (1914) and Hotelling (1931). Because the resource stock is fixed, the extraction of the resource over time cannot exceed the initial stock of the resource. Thus,

$$\int_0^T Q_t \, dt \leq S_0.$$

where, S_0 is the initial stock of resource and Q_t is the rate of extraction. The key question in the above problem, and addressed in the work of Hotelling and Gray is how to allocate the resource over time. From the viewpoint of the competitive resource owner, the resource is allocated such that the time path of extraction maximizes the present value of the exhaustible resource.

Consider a price-taking producer of a finite resource whose objective it is to maximize the PV of the resource. For simplicity, it is assumed that there are no costs of extraction. Thus the producer wishes to

$$\text{Max PV} = \int_0^T [Q_t \; P_t] \, e^{-it} \, dt \tag{3-1}$$

$$\text{subject to } \int_0^T Q_t \leq S_0. \tag{3-2}$$

The first-order condition for a maximum of equation (3-1) subject to equation (3-2), combined with the equilibrium condition that the market clears at each point in time yields the following:

$$P_t = \lambda e^{it} \tag{3-3}$$

where P_t is price and λ is the constant marginal user cost as defined by Scott (1953). Equation (3-3) suggests that in equilibrium, the price should increase at the rate of interest, i. If the price increases at the rate i, resource owners will be indifferent between producing in this period and any other period because the resource yields the same net present value at the margin at each point in time. This result was first illustrated by Hotelling, and the condition,

$$\dot{P}_t / P_t = i \tag{3-4}$$

is often referred to as the Hotelling rule.

The above simple model of resource extraction has been extended in several studies. First, the model is changed to accommodate positive extraction costs (Weinstein and Zeckhauser, 1975 among others). With positive extraction costs, equation (3-3) changes to,

$$[P - C'(Q)] = \lambda e^{-it} \tag{3-5}$$

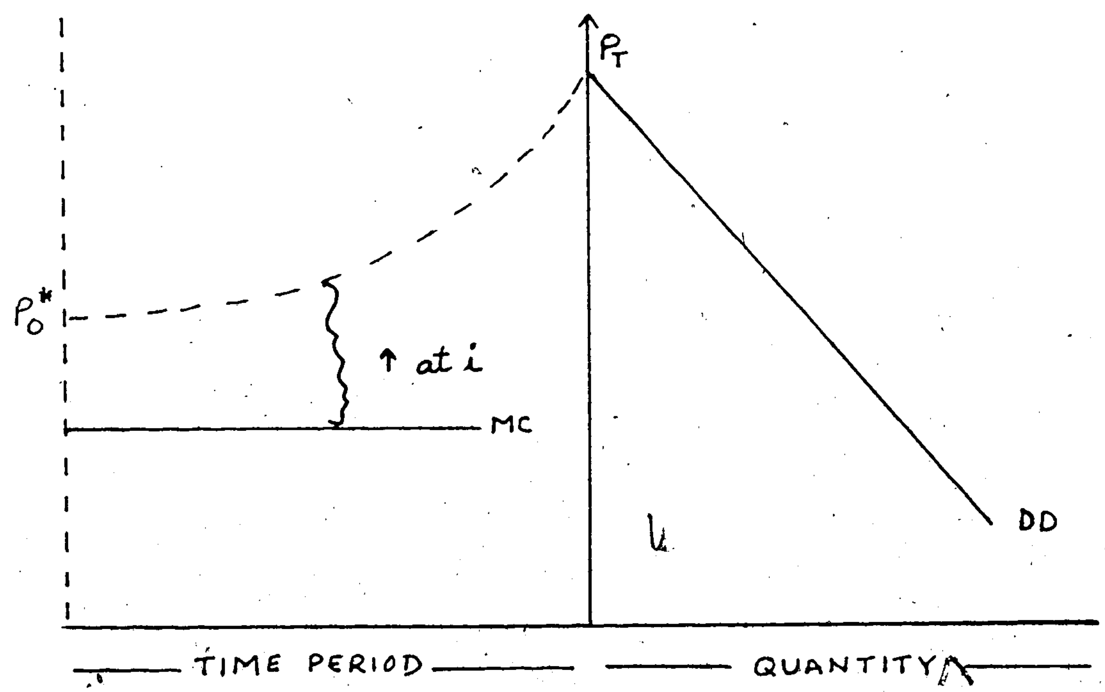
In equation (3-5) the net price instead of gross price increases at the rate of interest, i.

The above equilibrium condition explicitly determines the price path of the resource and implicitly determines the extraction rate. Given the price path, the extraction rate at each point of time can be determined by the demand curve. In Figure 3-1, the demand function $H_t = f(P_t)$ is given by DD. The price starts at a level P_0 and increases so that net price rises at rate i until P_T is reached, at which time the resource is exhausted. At this price level, demand is also equal to zero.

The determination of P_0 is crucial. It should be such that after increasing along the equilibrium path, price reaches the choke price (at which demand is equal to zero) just at the point of exhaustion of the resource. This presumes the presence of complete futures markets (Dasgupta and Heal, 1979). Let us define P_0^* as the equilibrium level of initial price. Consider a situation where $P_0 > P_0^*$ i.e the actual initial price is greater than the equilibrium initial price. In this case demand would be choked off before the resource was exhausted. If futures markets existed, producers would realize that the price was too high to exhaust the resource and therefore, they would make downward adjustments in the price.

Figure 3-1

Optimal Allocation of an Exhaustible Resource



Source: Weinstein and Zeckhauser (1975)

Alternatively, if $P_0 < P_0^*$, the resource will be exhausted before $H_t = 0$. Thus the producers will realize that profits could be increased by storing the resource today to sell it in the future. This conservationist measure would lead to a higher price in the initial period. Thus in both cases where $P_0 \neq P_0^*$, under the assumptions of futures market, P_0 will be driven towards the equilibrium P_0^*.

The above price profile is applicable under the conditions of perfect competition. What happens under non-competitive markets? Salant (1976), Weinstein and Zeckhauser (1975), and Peterson and Fisher (1976) among others deal with this issue. Consider a market where part of the resource stock is owned by a cartel and part by a number of sellers operating under competitive conditions. Let S_c be the stock of resource held by the competitive sector, and S_m the stock of resource held by the cartel. Also assume that Q_c is sales of the competitive sector, Q_m the sale of the monopolist, P* is the termination price at the end of first phase and $\Delta(P^*)$ is the cumulative sales of the cartel in the second phase. Then, Salant defines the two exhaustion conditions as:

$$Q_c\ (u,\ P^*)\ du = S_c \tag{3-6}$$

and $$Q_m\ (u,\ P^*)\ du +\ \Delta(P^*) = S_m \tag{3-7}$$

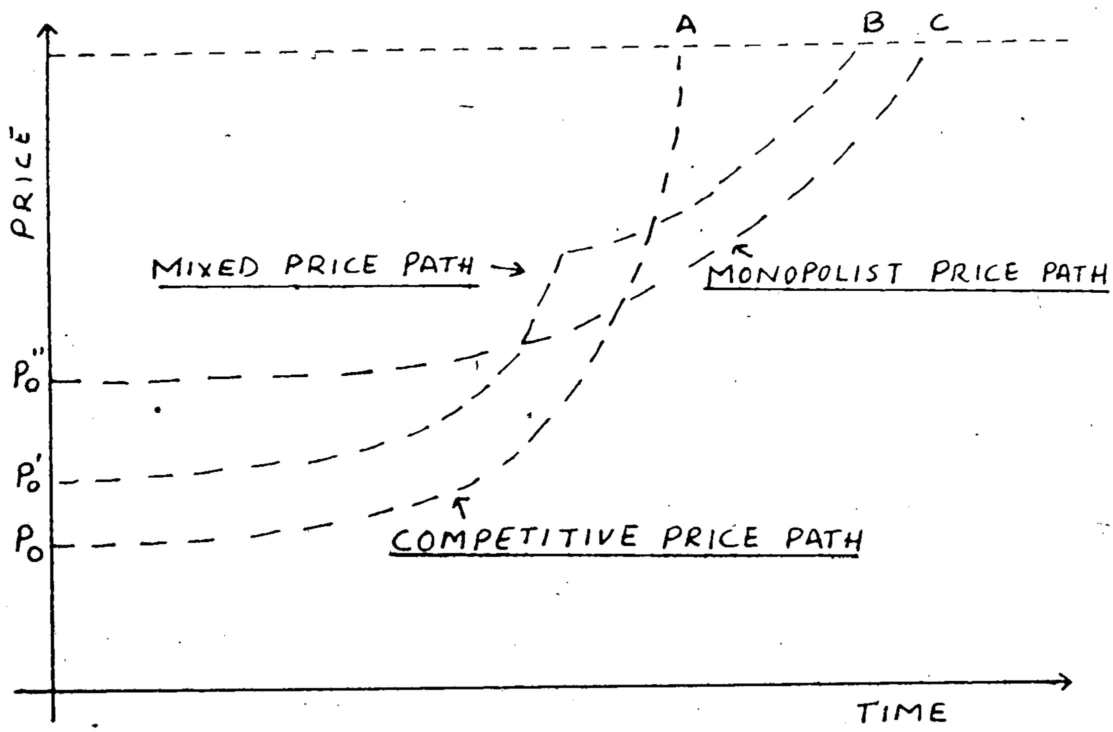
Equation (3-6) defines the equilibrium condition faced by the competitive fringe and equation (3-7) the equilibrium condition faced by the cartel. Extraction of the resource takes place in two phases. In the first phase, both the competitive sector and the cartel exist. The first phase lasts until the resource stock of the competitive sector is completely exhausted. After that only the cartel operates in the second phase. Equation (3-6) states that P^* and T should be so chosen by the cartel that the resource stock of the competitive sector is completly exhausted in the first phase. Equation 3-7 states that P^* should be so chosen by the cartel that the cartel sells its entire stock in the first and second phases.

Initially, when both the cartel and competitive sectors exist, the price and marginal revenue derived from the excess demand curve grow at the rate of interest, until P^* is reached. At P^*, the competitive sector's stock is exhausted and the cartel takes over the entire market. After P* for equilibrium the monopolist's marginal revenue grows at the rate i and the price grows at a rate less than i. Note that the excess demand curve is obtained by taking the total market demand and deducting from it the sales of the competitive sector at each period. When the stock of competitive sector is exhausted then the total market demand is also the demand faced by the cartel.

The equilibrium price path when the two sectors co-exist is illustrated in Figure 3-2. Given a linear demand curve, if only the competitive sector exists, then the initial price starts at a level below the mixed path and increases at the rate of interest. Alternatively, if only the cartel (or monopoly) exists, the initial price will start higher than the mixed price path and then increase at a rate less than the rate of interest.

Figure 3-2

Comparison of Price Paths Under Alternative Market Structures



Source: Salant (1976)

Price paths of the resource under varying quality of ores have also been studied (Salant, 1976; Herfindahl, 1967). It has been shown that with ore of two qualities (two different but constant per unit costs of extraction), the better quality ore will be mined first until it is exhausted and then the lower quality ore will be mined (for a detailed proof, the reader is referred to Dasgupta and Heal, 1979).

The price path of the extracted ore is continous at the point of switch. If it were not so, and the prices jumped upwards at T, then the owners of the first deposit could increase profits by stopping production just before T and producing after T. But this contradicts the result that the owners of first deposit do not produce after T. Similarly, if the prices fell discontinously at T, the owners of the second deposit would benefit by producing before T, which again contradicts the result.

Note the assumption of a fixed stock in all the studies discussed so far. Given a finite resource stock, the problem faced by the producer was to allocate the resource over time such that it maximized the present value of future profits. Optimal price paths for a fixed resource were derived under varying assumptions. Now, let us assume that the resource stock can be changed through exploration. Thus the reserve base can be maintained or increased through further exploration. Peterson (1975) and Pindyck (1978) were among the earliest authors to abandon the assumption of a fixed reserve stock from which the extraction took place. These authors determined the optimal price and production paths after allowing for the possibility of continous exploration. The model developed in the present study comes closer to these types of models, although an additional primary phase, development, is incorporated.

Peterson defines the PV function of the resource producer as follows:

$$PV = \int_0^T [PQ - C - E] \; \Delta(t) \, dt \tag{3-8}$$

where Q is the rate of production (or extraction), C is the extraction cost, E is the exploratory cost and $\Delta(t)$ is the discount factor, $\exp[\int_0^t i(\tau)d\tau]$, where $i(\tau)$ is the firm's discount rate at time τ. Note that if i is constant then $\Delta(t) = \exp(-it)$ which is similar to that assumed in the present study. C is given by a function $C(X, \dot{X}, G, t)$ where X is the cumulative production to date, G is the discoveries to date, and t is the time. It is assumed that $C_X > 0$ and increasing, $C_{\dot{X}} > 0$ $(C_{\dot{X}\dot{X}} \geq 0)$ and $C_G < 0$. Note that no explicit fixed costs are assumed.

The exploration cost is given by a function $E(\dot{G}, G, t)$, where $\dot{G}$ is the discovery rate. It is assumed that $E_{\dot{G}} > 0$ and non-decreasing $(E_{\dot{G}\dot{G}} \geq 0)$ and $E_G > 0$.

The above PV function is maximized subject to $\dot{X} \geq 0$, $\dot{G} \geq 0$ and $(G - X) \geq 0$. The last condition simply states that discoveries are greater than cumulative production. The optimality conditions indicate that if $C_X = 0$, then the marginal profit must increase at the rate of interest. But with $C_X > 0$ i.e. with increasing cost of extraction, the marginal profit should grow at a rate less than i to compensate for the penalty of higher extraction cost in the future. Similar results have also been obtained by Herfindahl (1967), Weinstein and Zeckhauser (1975), Levhari and Liviatan (1977).

For optimality of the above PV function, Peterson proves that the extraction rate should be set at the point where profits from another unit extracted equal the loss in present value of the resource stock caused by that unit of extraction. Also, exploration should be such that the cost of finding another unit equals the addition in present value caused by that unit. Peterson simulates his model to determine the effects of changes in various parameter values. His results suggest that: (i) a monopolist would over-conserve the resource; (ii) free entry stimulates excessive exploration and extraction because with free entry, exploration opportunities become common properties encouraging various firms to explore and drill faster and before the other competitors and (iii) high discount rates cause over-conservation in the long run. The last result is contradictory to earlier findings. The logic for such a result is as follows: high discount rates discourage exploration like any other activity. Lower exploration means low levels of proved reserves and since $C_G < 0$, it implies higher cost of extraction and therefore restricted production.

Pindyck (1978) formulates a similar model and derives optimal paths for prices and exploration. The producers in Pindyck's model take prices, P, as given and choose a rate of production, Q, from a proved reserves base, K. The average cost of production C_1 increases as the proved reserves base is depleted, i.e. $C_1'(K) < 0$. The proved reserves base increases with exploratory effort, E. The rate of flow of additions to proved reserves depends upon both E and cumulative additions, X, i.e. $\dot{X} = f(E,X)$, with $f_E > 0$ and $f_X < 0$.

The cost of exploratory effort C_2 depends on E, and increases with E i.e. $C_2'(E) > 0$. The producer maximizes a profit function similar to that of Peterson subject to $\dot{K} = \dot{X} - Q$ and $\dot{X} = f(E,X)$ and K, Q, E and $X \geq 0$. The first constraint shows that the change in proved reserves is equal to the difference between discoveries and production.

The equilibrium price path of the model shows that the impact of exploration is to cause price to rise more slowly than otherwise. If costs did not depend on K, however, the rate of change of prices even with exploration will be the same as that in the Hotelling case. But, the level of the price path is affected by exploration. This is so because under exploration, planned reserves including those that have yet to be discovered with exploration are larger than the initial reserves.

The pattern of exploratory effort, price and production that result from solving two simultaneous equations for prices and exploration, depend crucially on the initial value of reserves. The intertemporal trade off in exploration involves balancing the gain from postponing exploration so that its cost can be discounted, with the loss from higher current production costs resulting from a lower reserves base. If initial reserves are large so that the cost of production $C_1(K)$ is small, most exploration can be postponed to the future. On the other hand, if initial reserves are small, the average cost of production will be large and hence exploration must occur early on so as to increase the inventory of proved reserves and reduce the cost of production. Production will thus increase initially and later reserves and production will fall as exploratory effort diminishes (Pindyck, 1978).

2. Review of Empirical Literature

Empirical estimates of supply elasticities derived from formal modelling procedures are at best representations of specific historical relationships. Therefore, the use of such models in forecasting is often characterized as "looking forward through the rearview mirror" (Stobaugh and Yergin, 1979 p.234). Models explaining the same phenomenon are often formulated under varying assumptions, are estimated with varying techniques involving different types of data, of different levels of aggregation and from different time periods. Thus these models may yield different estimates relating to the same phenomenon. Such is clearly evident in the following review of empirical literature on supply modelling. The review suggests a whole range of supply elasticities with respect to the various exogenous variables, derived for varying models using different data, and different estimation techniques.

The empirical studies in the area of supply of oil and natural gas can be classified under the following categories:

(a) <u>Ad hoc</u> Approach

(b) Production Theory Approach

In this section we briefly summarize the relevant studies under these two categories.

<u>(a) Ad hoc Approach</u>: These types of studies have developed models based on the variables that are believed to be relevant. Studies in this classification do not specify an explicit production function. The approach followed is <u>ad hoc</u>, although the estimating equations look similar to those derived from an application of rigorous economic theory. Discoveries, number of wells drilled and the success ratio are explained with the help of economic variables such as costs and prices. Policy variables such as royalties and taxes are generally included through prices. Wellhead price or price of the reserves in the ground are used as explanatory variables.

Models formulated in this category explain the oil and gas activity by a set of equations of the form,

$$Y_i = f(X_i)$$

where Y_i is alternatively (1) wildcat wells drilled, (2) average discovery per successful well and (3) the success rate obtained in drilling wells. X_i is (1) the price of oil, (2) the price of natural gas, and (3) the lagged dependent variable. In most cases, the dependent variables Yi are explained by the same combination of independent variables, Xi.

Fisher's (1964) model of the U.S. petroleum industry is the first attempt to model econometrically the supply of new discoveries. The crude oil discoveries are calculated as the product of the three dependent variables stated above and each is specified in terms of the same independent variable. Because the equations are double-log forms, the elasticity of oil discoveries with respect to any independent variable is the sum of the coefficients on that variable in each of the three equations. The exogenous variables in the model are (i) the wellhead price of oil as a proxy for economic incentives, (ii) the lagged dependent variable representing an increase in information, (iii) the lagged average size of oil discoveries, (iv) the time spent on geophysical and core drilling crew time to measure the information gathering activity and (v) Texas shutdown days to measure the production restrictions by the state. Because oil and natural gas are produced as joint products, lagged average size of natural gas discoveries is incorporated as yet another lagged dependent variable.

Fisher's results indicate that the price elasticity of supply of new discoveries of crude oil is 0.3, and the price elasticity of wildcat drilling is 2.85. The study indicates that an increase in economic incentives leads to more wildcat drilling but because this increase takes place on poorer prospects the size of discovery is small. The high cost associated with poor prospects can only be justified by increased economic incentives.

Erickson's (1970) work does not differ substantially from Fisher's. Erickson uses a similar set of equations with a different wellhead price of oil. The price of oil is calculated as a weighted average of prices in each of the five petroleum producing districts. With this price, Erickson obtains the higher price elasticity of new discoveries of 0.9. An interesting feature of Erickson's model is that the effect of market demand prorationing is elaborately dealt with. He concludes that the elimination of market demand prorationing would not only result in increases in the rate of establishment of new discoveries, decreases in development and operating costs, and a decrease in the period of time for recovering investments, but also in lower prices resulting from the competition to sell to a given total market.

Erickson and Spann (1971) apply the theory of joint production and supply to the problem of oil and gas discoveries and extend Fisher's model to include an equation for average natural gas discovery size. The exogenous variables are similar to those specified in Fisher's model. The price elasticity of crude oil discoveries in this model is 0.83 and the price elasticity of gas discoveries is 0.69. These price elasticities compare with an oil price elasticity of 1.48 for wildcat drilling and a gas price elasticity of .35 for wildcat drilling. Note that the oil price elasticity of wildcat drilling is higher than that of crude oil discoveries while, the gas price elasticity of wildcat drilling is lower than the elasticity with respect to gas discoveries. Thus the new oil discoveries are much less sensitive to economic incentives than the wildcat drilling. The opposite is true for gas. Erickson and Spann attribute this to the deterioration in the average size of oil discoveries in mature areas. As prices increase, these relatively uneconomic prospects are drilled and because they yield a smaller size of discovery, the price tends to have a negative impact on average size of discovery. The situation is reversed for gas, where there exists an inventory of large gas prospects which have not been drilled largely because of lack of markets. With an increase in the price of gas, drilling takes place in these relatively large gas prospects, yielding a higher size of discovery.

In another study, Erickson, Milsapps and Spann (1974) derive an estimating equation for the stock of crude oil reserves. They assume that the principal determinants of desired reserves are the expected price of oil and the finding cost (stated as user cost in the study) of crude oil reserves. Finding cost is calculated per barrel of additional reserves found and is calculated net of tax incentives. Thus, the effect of tax incentives is measured through their effect on finding cost. Their results indicate a long-run price elasticity of oil reserves equal to unity and a long-run finding cost elasticity of reserves equal to -0.71. Thus as the finding costs increase, the stock of crude oil reserves decreases. As an alternative, they estimate a constrained model assuming the absolute price and finding cost elasticity are equal. By so doing, they derive a positive and a negative elasticity of 0.76 for prices and finding costs respectively.

Khazoom's (1971) model considers the supply of gas in terms of (a) new discoveries (of both associated and non-associated gas) representing the amount of recoverable gas estimated to exist in newly discovered reservoirs and (b) extensions and revisions (of both associated and non-associated gas) which are said to comprise additions to or subtractions from the initial estimates of gas discoveries due to changing economic conditions (e.g. current prices of oil, gas and natural gas liquids), or the availability of new information on reservoir size or reservoir characteristics (such as permeability, porosity, interstitial water etc.) or subsequent development. Both the new discoveries and extensions and revisions are explained in terms of (a) the regulated ceiling price of gas, (b) the price of oil, (c) the price of natural gas liquids, and (d) lagged endogenous variables. Linear and quadratic specifications are both estimated. His results indicate that for the first equation explaining the new discoveries of gas, the ceiling price of gas has a positive and statistically significant coefficient, the oil price has a negative and statistically insignificant coefficient, and the price of liquids has a positive but insignificant coefficient. The lagged dependent variable has a positive and highly significant coefficient. The second equation explaining the extensions and revisions is less satisfactory in terms of goodness of fit, although all the variables have significant coefficients. For both the new discoveries and extensions and revisions, the linear specification performs better than its quadratic counterpart.

An interesting feature of Khazoom's study is that he tries to simulate a time path of discoveries response to a gas price increase. This time path under given initial equilibrium conditions for price of oil and the price of natural gas liquids provides estimates of short, intermediate and long-run elasticity of gas discoveries. His results indicate that the long-run elasticities are generally greater than the short-run elasticities.

MacAvoy and Pindyck's (1973) study is more comprehensive than any of the prior studies. All phases of the natural gas industry are modelled from exploration through production, transportation and distribution. They examine the effect of the existing regulatory policy and other alternative policy proposals on gas reserves, production, demand and prices .

The model so developed is used to perform simulations using different policy options to determine the effects on the size of the gas shortage. Three policy options are considered. The first policy alternative is a complete deregulation of wellhead prices, the second involves more rather than less regulation, and the third is maintenance of the status quo. To analyze the effects of these policies and to provide further simulations they formulate an economic model of the natural gas industry.

This model deals simultaneously with two markets; (1) a field market for reserves where gas producers sell new reserves to pipeline companies at the wellhead price, and (2) a wholesale market for production where pipeline companies sell gas to retail utilities and industrial consumers. These two markets are linked through the interstate pipeline companies. The variables endogenous to the field market are (a) discoveries of non-associated and associated gas reserves; (b) extensions and revisions of associated and non-associated reserves; and (c)number of exploratory wells drilled.

In the wholesale market, the endogenous variables consist of the demand for gas and the wholesale prices for three sectors, namely industrial sales, sales for resale that are ultimately industrial, and sales for resale that are ultimately residential and commercial.

The independent variables in the field market are lagged total revenue from oil and gas production, lagged average total drilling costs, dummy variables to distinguish among regions, sample variance of discovery size in each region, average field price of natural gas, average drilling cost, and cumulative number of wells drilled.

The results indicate that partial deregulation of field prices (i.e., complete deregulation of new contract prices subject to a national ceiling on all new prices) would have engendered increases of

50% to 60% in prices over the years 1972-1980, which would have cleared all excess demand in the production markets. However, if price increases had been limited to increases in the historical cost of producing gas, MacAvoy and Pindyck estimate that the excess demand would have increased through time, and in 1980 it would have been 9 trillion cubic feet (Tcf) as compared to 3 Tcf in 1974. Under this assumption, the prices would have been allowed to increase at one cent per annum per Mcf. Finally, if the status quo were maintained, i.e. if the prices were increased by 2 to 4 cents per Mcf every year, then the shortfall in supply would have been 2.5 to 3.5 Tcf in the mid-1970's increasing to 5.3 Tcf by 1980.

The model developed by Rice and Smith (1977) also considers both the demand and supply of crude and refinery products without aggregation or restrictive assumptions of perfect competition. The model has forty-two nonlinear equations and is estimated over the period 1946 - 1973.

The Rice and Smith model can be divided into four sections - pricing, production, costs, and demand. The supply relations specify the price of each refinery product. Prices are assumed to be a function of the quantity supplied, the weighted average price of domestic and foreign crude and the product of the relative yield of each product to that of gasoline and the average price of crude.

The production sector of the model is based upon the work of

Fisher (1964) and MacAvoy and Pindyck (1973). This sector consists of seventeen equations, six of which are stochastic behavioral equations and eleven of which are identities. The most important variable determined in this sector is the drilling activity. Exploratory wells are specified to be a logarithmic function of average drilling costs (per well), the expected revenue from crude oil sales, and the expected number of successful exploratory wells.

Two types of costs are analyzed - finding and development costs. Both of these costs are based on the total amount of drilling activity, the average depth of that activity, and production restrictions associated with the development of crude.

The R^2 of all equations estimated in the model is high, ranging between .79 to .99. The price effect on new field wildcat drilling activity reported in this model is lower than that reported by Fisher (1964) and Erickson (1970). However, the difference could be because the present model uses an expected price rather than an actual price.

In recent years, three models have been developed and tested with Alberta data. Winter and Craig (1981) formulate a model of natural gas reserves additions to identify factors that have influenced the finding of gas reserves in Alberta between 1957-1977. A wide range of exogenous variables is considered including the size of the reservoir, probability of success, netback prices, finding and development costs and alternative uses of capital. In the final equation explaining the natural gas reserves a profitability factor, a depletion variable and an industry activity variable are included as exogenous variables. The profitability variable is calculated as a function of average discovery size, probability of success, cost, prices and marketability. The depletion variable is measured by the cumulative number of successful gas wells. The industry activity variable is measured by exploratory gas footage. The model is tested for nine geographical areas in Alberta. The model performs differently for different areas. The R^2 varies from .29 to .94. The profitability variable is found to be significant for 6 areas, the depletion variable is significant in 7 areas and the activity variable in 5 areas. Signs of some of the coefficients are contrary to a-priori expectations.

In another model, Foat and MacFadyen (1983) estimate an equation for aggregate drilling with exogenous variables such as the selling price of oil and gas, drilling and development costs, royalty and tax regulations, reservoir characteristics, success ratio, and availability of capital, and the average size of oil and gas discoveries. Only the price of oil and gas, net of royalties and the average size of oil and gas discoveries, is found to be significant for Alberta.

In more recent work, Scarfe and Rilkoff (1984) study the determinants of investment expenditure in the exploration and development phases of the crude petroleum and natural gas supply process. They construct and estimate an Alberta oil and gas activity model and use it to address several policy questions such as the following: has Canadianization of the petroleum industry increased the cost of capital to the industry; does the cashflow of petroleum industry effect its rate of investment; what fiscal changes should be introduced to improve economic efficiency and achieve security of supply; and what has been the impact of the NEP.

Two sets of econometric equations are specified, one for exploration and one for development. Both dependent variables are assumed to be functions of the prices of oil and gas and planned new reserve additions. Note that the prices of oil and gas are not the wellhead prices but are the prices of the oil and gas in the ground, referred to as the reserves price. Planned new reserve additions are further assumed to depend upon volume of production from reserves and the reserves price. In the reduced form, both exploration and development are functions of the reserves price, the production from reserves and a lagged dependent variable. In estimation, exploration and development are measured by the various types of exploration and development expenditures such as geological and geophysical expenditures, drilling expenditures, land expenditures and field equipment expenditures.

The results indicate that elasticities of the exploration equation are highly significant. The price of reserves is found to be an important variable in explaining the variations in exploratory expenditures. The reserves price as a determinant of development expenditures is less significant. The production variable is more significant for the development phase. One of the important conclusions of the study is that reductions in the upstream taxes are important to achieve security of supply and overall economic efficiency in the industry.

Although the above studies have contributed significantly to the understanding of the investment and supply response for the petroleum industry, they have often been criticized on the grounds of being inductive and lacking in rigorous economic modelling, being highly aggregative in nature, and having an inadequate treatment of petroleum deposits as non-renewable assets.

<u>(b) Production Theory Approach</u>: The models developed in this group of studies are based on rigorous economic analysis of a profit maximizing firm. The investment and output patterns for oil and gas firms are derived by maximizing the firm's profit function subject to the constraints of a production function.

Epple's (1975) work is rather innovative. In his model, exploration is viewed as a production process in which inputs (exploratory wells and oil-bearing land) are used to produce discoveries of crude oil and natural gas. The objective is to estimate a long-run model of crude oil and natural gas discoveries. A profit-maximizing firm engaged in exploration maximizes net profits subject to a production function (in this case a constant elasticity of transformation - CET function). Such a maximization results in a set of derived demand equations for inputs to exploration, and a set of supply equations for crude oil and natural gas discoveries. In final estimable form, the discoveries of oil and gas are a function of the after-tax discounted price of oil and gas in the ground (reserves prices), and the after tax cost of exploration. The total footage drilled is also explained by the after-tax cost of exploration, the price of oil and gas in the ground, plus a trend variable

Of interest in this study are the long-run price elasticities of supply of crude oil and natural gas discoveries, the elasticity of transformation between crude oil and natural gas discoveries and the shifting of the supply equations stemming from the exhaustion of discovery opportunities. The price in this model, specified as a reserves price is derived by taking a ratio of the net present value of a discovery and the original oil-in-place.

Cox and Wright (1976) construct a model of investment in petroleum reserves and estimate it for U.S. petroleum industry. An investment demand function for petroleum reserves is derived on the assumption that the producers maximize the present value of their after-tax cash flows subject to a CES production function, and an accounting identity. The latter constraint relates changes in petroleum reserve stocks to flows of gross additions to reserves and output from reserves.

The functional form of the model formulated later in the current study comes quite close to the Cox and Wright investment model, the difference being the inclusion of three phases, exploration, development and production as opposed to the latter two phases in the Cox and Wright model. We thus outline the Cox and Wright model in considerable detail. The after-tax cash flow in Cox and Wright model at time t is written as

$$N(t) = P(t)Q(t) - C_1(t) - C_2(t) \tag{3-9}$$

where $C_1(t)$ and $C_2(t)$ are the investment and non-investment costs at t. The revenue term $P(t)Q(t)$ is calculated net of royalties, production and severance tax and federal corporate income tax. The distinction between $C_1(t)$ and $C_2(t)$ is in line with the tax provisions.

A CES production function, which forms one of the constraints is specified in general form as

$$F(Q(t),\ S(t),\ L(t),\ t) = 0 \tag{3-10}$$

where $S(t)$ is the full-time equivalent stock of proved reserves, and L is the non-reserves input in the production function. The full-time equivalent stock of proved reserves is further written as,

$$S(t) = m(t)^n\ K(t) \qquad 0 \leq m(t) \leq 1,\ n > 0 \tag{3-11}$$

where m is the market-demand factor and is calculated as a ratio of the number of days the wells are in operation to the number of days in a given month. n is the elasticity of the full-time equivalent stock of reserves with respect to the market demand factor, m and K(t) is the stock of proved reserves.

Finally, $\dot{K}(t)$ i.e. the change in proved reserves, is specified as

$$\dot{K}(t) = f(I(t),t) - Q(t) \tag{3-12}$$

where f(I(t),t) is a function defining gross additions to proved reserves at time t. In this function, I is defined as expenditures made on acquiring reserves. In its final estimable form $\dot{K}(t)$ is a function of a relative price variable, quantities of marketed output of oil and gas, the extent of state market demand prorationing, and a time variable. The relative price variable which measures profitability of finding reserves is a ratio of marginal after-tax net return to marginal after tax net cost of holding reserves. In calculating this variable several factors including the oil pricing policy and the other government policies on taxation of oil and gas are considered.

All estimated coefficients of explanatory variables are highly significant, and indicate the effectiveness of several public policies in determining investment in reserves. First, the significance of the relative price variable implies that the special tax provisions have increased the investment in reserves. Second, the market demand prorationing policy forced an increase in the resources output ratio. Third, the oil import quota affects investment positively by restricting the quantity of imports. Thus reduced imports lead to a higher price in the U.S. market and the higher price in turn increases the quantity supplied.

In a study using Canadian data, Eglington (1975) defines two markets for the supply of oil and gas. The first is the asset or reserves market, and the second is the flow or output market. The prime objective of his work is to identify the components of both the demand and supply in the reserves market, and estimate the economic linkages between the incentive to explore for oil and gas and the rates of wildcat drilling and subsequent reserves discovered.

The expected reserves equation is defined as a product of the success rate and average pool size and is therefore a function of exploratory drilling, inventory of undrilled prospects and average size of oil pools. The optimal exploratory drilling equation is derived by taking the first derivative of the profit function. The optimal drilling variable is then substituted into the expected reserves equation to give the theoretical equation for empirical analysis.

Like Epple, Eglington derives a demand price for reserves defined as the average price that the producer would pay for undeveloped recoverable reserves. The demand price, in this formulation, is influenced by anticipated field operating costs, development costs, well productivities, length of production life, royalty rates, income taxes, cost of money, delays before initial production, and production of joint products (Eglington, 1975 p.8). One of the key contributions of Eglington's thesis is the development of a methodology to divide exploratory activity into oil intent and gas intent. Exploratory activity is measured by new field wildcatting. His results suggest that the short-run supply elasticity of new field wildcatting (defined in terms of total number of wells drilled) with respect to the reserves price of oil (not the wellhead price of oil) varies from 0.3 to 0.4. Similarly, the elasticity of wildcat drilling activity with respect to the reserves price of gas was found to be 0.1. However, he feels that these supply elasticities would vary tremendously as the resource was depleted and that shifts in the supply curve would occur.

The work of Uhler (1976, 1979) and Foat and MacFadyen (1983) differs from all earlier works in that it introduces a play specific discovery process. A 'Play' is defined as the discovery of significant accumulations of oil in a particular geological formation. Uhler defines a production function for oil discoveries which is based on exploratory inputs (drilling, land and geophysics), and another variable measuring the effects of geophysical information and depletion of undiscovered reserves (cumulative oil reserves). The production function for oil discoveries is specified as,

$$Y_0 = h(X_0)\ f(R_0) \tag{3-12}$$

where Y_0 is the sum of discoveries over plays, $h(X)$ is an exploratory input function, and $f(R_0)$ is a cumulative reserves function. Since he was unable to obtain data on some of the play specific exploratory inputs that variable is aggregated over all plays, but the cumulative reserves variable remains play specific. The function, $f(R_0)$ is of the form

$$f(R_0) = A_0 \exp(-b_0\ R_0) \tag{3-13}$$

and $h(X_0)$ is specified as the following translog formulation:

$$\ln h(X_0) = a_{00} + \sum_i a_{0i} \ln X_i + 1/2 \sum_i \sum_j a_{ij} \ln X_i \ln X_j \tag{3-14}$$

where X_i are the inputs of oil or gas intent drilling.

With the above model, Uhler predicts the future discoveries of oil and gas under two alternative situations: one in which the oil discoveries and cumulative reserves are aggregated across plays (which he calls the aggregate model); and the second in which each oil play is treated independently via the introduction of a dummy variable (called the disaggregated model). The disaggregated model, performs better than the aggregated model. Observed and predicted finding costs are derived by dividing the known expenditures by actual and predicted discoveries. His results indicate substantial increases in oil finding costs in Alberta in the '70s, and also a general decline over time of the product price to finding cost (output/input price) ratio.

Foat and Macfadyen have conducted similar play analyses for the oil discoveries in Alberta. Seven oil-bearing formations or plays in Alberta are considered. A common functional form of the reserves equation for all plays is assumed. The relationship underlying their functional form assumes that discovery of oil pools requires that wells be drilled and the petroleum reservoir penetrated and also that specific oil play exhibits diminishing marginal returns over time. Thus the exploratory variables are the number of wells drilled into the formation and the cumulative penetrations in negative exponential form. The exact functional form is

$$Res_t = \exp^{a0}\ Pen_t^{a1}\ \exp^{a2\ Cum\ Pen_{t-1}} \quad (3\text{-}15)$$

where Res_t is the oil reserves found in year t, Pen_t is the number of penetrations in year t, and Cum Pen_{t-1} is cumulative penetrations to year t-1. Note that number of penetrations are measured by number of wells drilled. It is anticipated that $a_1 > 0$ and $a_2 < 0$. The results suggest that this holds true for only four out of seven plays.

CHAPTER IV: THE MODEL

The last two chapters provide information on (1) the regulatory structure under which the Alberta petroleum industry operates and (2) the state of the art of modelling in resource economics. In this chapter we attempt to formulate a model of oil and gas supply. The chapter is divided into six sections: the first provides an introduction to the nature of energy supply modelling; the second formulates the model; the third specifies the form of the equations to be estimated in this study; the fourth introduces some modifications to the estimating equations; the fifth derives policy implications arising from equations to be estimated; and the last section specifies an alternative exploration sub-model.

1. Energy Supply Modelling

The model formulated in the present study is one of continuous exploration, development, and production. Following Pindyck (1978), the model implicitly assumes that while the "reserves in place" may be fixed or exhaustible, "potential reserves" are unlimited, (at least in the short term). The reserve base is subject to continuous change; it is created, maintained or increased through an ongoing process of exploration, and diminished through production. The process of reserve discovery and production is carried out in several stages. The initial stage is characterized by reserve discovery and development with relatively small levels of production. The later stages may be characterized by increasing, decreasing or stable reserves, depending on the amount of exploratory effort and the success obtained. Although the potential reserves are unlimited, implying that some reserves may always be generated through exploration, diminishing returns set in in the later stages of reserve discovery. Thus in the later phase of exploration more and more exploratory effort may be required to generate a unit of reserves.

Exploration is often likened to the research and development activity of a manufacturing firm. It is an information generating process whereby the information generated either substantiates or negates the presence of oil or gas. It involves activities directed towards finding oil and gas and consists of geological or geophysical studies and interpretation, and eventually exploratory drilling. First, land for exploratory purposes is acquired through a license or other institutional mechanisms, then geological and geophysical tests are performed and, if these look promising, exploratory drilling is done.

If exploratory activities indicate the presence of oil and gas, firms may move into a development phase. This stage entails the establishment of productive capacity, additional delineation drilling, and installation of surface facilities for the recovery of crude. In practice, both exploration and development aim at establishing the size of the reserve base. But because exploration involves wildcatting and occurs in generally unknown areas and reservoirs, the risk in exploration is substantially greater than that in development[1]. It is assumed that exploration generates estimates of probable reserves. Probable reserves according to the Canadian Petroleum Association (CPA) are defined as "a realistic assessment of the likely size of recoverable reserves, from newly discovered oil or gas fields, based on estimates of the ultimate size of such fields at that time"[2]. Development on the other hand generates proved reserves, which are defined as "estimated quantities of oil and gas, which the analysis of geological and engineering data and further delineation drilling indicates as likely to be recoverable, with reasonable certainty, from established oil or gas pools or fields". Note that there is no uniform practice within the industry to assign the probable reserves to exploration or proved reserves to development. However, for the present analysis, as exploration initially establishes a discovery, although not with so much certainty, we hypothesize that the reserves generated through exploration are mostly probable reserves. Accordingly, as development includes further drilling to establish the reserve base with greater certainty, it is hypothesized that development activity would mostly generate proved reserves.

Finally, the production phase involves lifting or extracting the crude from the reservoir. It includes activities such as pumping, scrubbing, gathering for storage, supervision of the area, and often subsequent treatment of wells to increase their productivity.

In the present formulation, we model each of these three activities sequentially. In its simple form, the sequence is as follows: Exploratory activity first generates probable reserves. The estimates of probable reserves are turned into proved reserves through development activity. The proved reserves are extracted in the production phase.

In line with neoclassical investment theory, we specify a profit function which is maximized over the life of a resource subject to certain constraints. The solution to this profit maximization problem yields a set of equations which define the optimal levels of exploration, development and production. Alternatively, these three phases could be treated as independent production decisions. For example, exploration would involve the production of 'probable' reserves of oil and gas, development would relate to the production of 'proved' reserves of oil and gas, and of course extraction would result in oil or gas production. Thus, there would be three individual markets for each of these three phases. Although the reserves market concept has gained some support in recent years (Millington, 1975, Epple, 1975), we here assume that exploration, development and production are interdependent decisions, and that it is therefore more appropriate to model them under a single profit maximization decision. Implicitly we assume that there is no significantly active market for reserves as such,[3] and that all three investment decisions are undertaken by one producer. Note that this assumption does not preclude the possibility of exploration and/or development activites being performed under contract. In such a case, the producer still makes decisions regarding the optimal levels of investment.

2. Derivation of The Model

In what follows we assume that an oil and gas firm maximizes the present value of after-tax cash flow. We write the profit maximization problem of the oil and gas firm as

$$\text{Max } PV = \int_0^T (e^{-it}[PQ - C_E.E - C_D.D - C_N.N]) \, dt \qquad (4\text{-}1)$$

PV is the integral of the difference between the revenue term (PQ) and the three cost terms $[C_E.E,\ C_D.D,\ C_N.N]$. All prices and costs are calculated net of royalties, taxes and tax deductions or allowances[4]. P and Q here are respectively the composite price and composite quantity of oil and gas produced, C_E and C_D are respectively the exploratory and development costs per foot, C_N is the operating cost per unit of variable input, E and D are respectively the total exploratory and development feet drilled, and N is the total units of variable input utilized to extract Q[5]. All terms in the bracket are specified at t although in the current model for simplicity of expression we refrain from the use of t. Finally, i is the rate of discount and T the time horizon of the firm.

In physical terms exploration can be measured by drilling and or seismic activity and development can be measured by drilling. As seismic activity is sometimes unobservable, especially for individual fields, we concentrate on drilling activity for both exploration and development. Drilling can measured by either the number of wells or by the amount of footage drilled. Previous studies have used both the number of wells drilled (Erickson & Spann, 1971; MacAvoy and Pindyck, 1973) and the footage drilled (Epple, 1975). However, the choice in most cases is arbitary. In samples where there is a wide variation in the average depth of wells (for example, Alberta), a reference to the number of wells drilled as a measure of exploration is misleading. For example, a well of 2000 metres entails a higher investment than a well of 500 metres, although in both cases the reference is made to a single well. However, the argument can be reversed to suggest that the total amount of footage does not provide an indication of the total number of wells (unless the average depth of a well in a particular area is given). As the production is defined over a well, this may be confusing.

Similarly, cost can be defined per well or per foot drilled. Most statistical agencies (example, CPA) report aggregate investment expenditures and thus they can be allocated either way. However, the government incentive programs (the exploratory drilling incentive and more recently the development drilling incentive) are structured on the basis of cost per foot.

The choice of an appropriate production function that will constrain our maximization problem is complex. An ideal choice is one from the family of "flexible" production functions[6]. This new variety of functional forms is flexible in its property of not constraining the various elasticities of substitution. These production functions provide a second order local approximation of an arbitrary twice differentiable production function. A priori, their global approximation properties are not known, although these properties, such as convexity, can be tested.

Of these functional forms, the translog production function has recently been widely used. This multi - input, multi - output production function is specified in terms of logs of all the inputs and outputs, the logs of the squares of inputs and outputs and the logs of the cross product terms. Thus,

$$\begin{aligned}\log Z = \alpha_0 &+ \sum_{i=1}^{n} \alpha_i \log Y_i + \sum_{j=1}^{m} \beta_j \log W_j \\ &+ \frac{1}{2} \sum_i^n \sum_j^n \gamma_{ij} \log Y_i \log Y_j \\ &+ \frac{1}{2} \sum_i^m \sum_j^m \delta_{ij} \log W_i \log W_j \\ &+ \sum_i^n \sum_j^m \rho_{ij} \log Y_i \log W_j\end{aligned}$$

where Y is output, W is input, and Z is the production possibility frontier.

Under the restrictions of groupwise additivity and commoditywise additivity in the commodities that comprise the group, (Christensen, Jorgenson and Lau, 1973)[7], the above function reduces to the CET-CES production function.

Although the translog functions (or similar formulations) are the ideal choice because they are generalized and employ less restrictive assumptions, the use of these functions is often limited by three basic econometric problems: (1) the number of parameters to be estimated under these functions is large; for example, for a two output, two input case, the number of parameters to be estimated is fourteen, and with a small sample of data, this raises econometric problems. Note the number of parameters can be reduced by certain parameteric restrictions, although restrictiveness of the production function increases and this generalized production function may approximate the Cobb - Douglas (C-D) or Constant Elasticity of Substitution (CES) production function; (2) the squared and cross product terms introduce multicollinearity[8], and (3) using it as a constraint to our profit function generates estimating equations which are non linear in their parameters.

Due to these econometric problems, the choice we are left with is of a simpler form. The simplest of the functions is a Cobb-Douglas

(C-D) function. However C-D is not appropriate for multiple output. For our purpose we adopt a CET - C-D function. This form was introduced by Powell and Gruen (1968) and has recently been used by Epple (1975) in modelling petroleum discoveries in the United States. The function is specified as:

$$[\beta Q_{oil}^{d} + (1-\beta) Q_{gas}^{d}]^{1/d} = A_1 K_2^m N^n \quad (4\text{-}2)$$

where Q_{oil} and Q_{Gas} are the quantities of oil and gas production respectively, K_2 is the level of proved reserves of oil and gas[9] and N is the level of variable input used in the period. A_1 is the scale parameter, m and n the distribution parameters which define the relative factor shares in the output of oil and gas, and d is the transformation parameter between outputs of oil and gas[10]. The above function implies constant elasticity of transformation along a production possibility frontier, although unlike the C-D function it does not impose the restriction of unitary elasticity. Empirically, it implies that for a specific data set, the elasticity of transformation is constant for all levels of outputs. Within a particular geological region (comprised of fields or pools with similar geological characteristics), the assumption of constant elasticity of transformation may not be very restrictive. Between the various geological regions, however, this elasticity of transformation might vary.

For now we denote the left-hand side of equation (4-2) by Q, i.e.,

$$Q = (\beta Q_{oil}^{d} + (1-\beta) Q_{gas}^{d})^{1/d}.$$

'β' as in 4-2 is the proportion of Q_{oil} in a composite output Q of oil and gas. Similarly, $(1 - \beta)$ defines the share of Q_{gas} in Q.

The hypothesized time rate of change of the level of proved reserves (K_2) is :

$$\dot{K}_{2t} = f(K_1, D) - Q$$

$$\text{or} \quad \dot{K}_2 = A_2 K_1^{\gamma} D^{\delta} - Q \qquad (4\text{-}3)$$

where f( ) is the addition to K_2 which depends on development activity D, and the stock of probable reserves, K_1. We assume that the stock of probable reserves is generated through exploration. To this stock (fixed capital), development activity (variable input) is applied to generate additions to proved reserves. For simplicity, we assume that the function f follows a Cobb-Douglas specification.

In equation (4-3), K_1 is the level of probable reserves of oil and gas measured in '000 of BTU at the begining of t, D is the total development feet drilled in t, γ and δ are elasticity parameters with respect to K_1 and D respectively, and A_2 is a scale parameter. Both γ and δ may be treated as representing success parameters, with γ measuring the success obtained in converting the probable reserves to proved reserves and δ measuring the success obtained in development drilling in generating proved reserves. Hereafter both γ and δ are referred to as success parameters.

We assume that the two inputs, probable reserves and development activity are to some extent substitutable. For example, if the stock of probable reserves is large, then a given amount of additions to proved reserves could be generated with a small amount of D. However, if the stock of probable reserves is small, then to generate the same amount of additions to proved reserves more D will be required. We choose a C-D specification which implies a unitary elasticity of substitution between the inputs. We realize that this assumption is restrictive, but our choice of an appropriate functional form is constrained by a need to keep the model to an econometrically feasible estimation structure.

Thus equation (4-3) states that proved reserves increase by gross additions, $f(K_1, D)$ and decrease by the amount extracted, Q.

The time rate of change of the level of probable reserves is assumed to be given by

$$\dot{K}_{1t} = A_3 E^{\alpha} \tag{4-4}$$

where α is the elasticity parameter of discovering probable reserves with respect to E. Thus (4-4) defines the conversion of exploratory footage, E, to probable reserves. As in (4-3), α can be referred to as measuring the success obtained in exploration.

To maximize (4-1) subject to (4-2), (4-3) and (4-4) we form the Lagrangian, i.e.

$$\begin{aligned} L = \int_0^T (e^{-it} & (PQ - C_E.E - C_D.D - C_N.N) \\ & + \lambda 1(t)\ (Q - A_1\ K_2^m\ N^n) \\ & + \lambda 2(t)\ (K_2 - A_2 K_1^{\gamma} D^{\delta} + Q) \\ & + \lambda 3(t)\ (K_1 - A_3 E^{\alpha}))\ dt \end{aligned} \tag{4-5}$$

The Euler Lagrange equations are as follows:

$$\frac{\partial L}{\partial Q} = e^{-it}P + \lambda_1(t) + \lambda_2(t) = 0 \qquad (4\text{-}6)$$

$$\frac{\partial L}{\partial E} = -e^{-it}C_E - \lambda_3(t)A_3\alpha E^{\alpha-1} = 0 \qquad (4\text{-}7)$$

$$\frac{\partial L}{\partial D} = -e^{-it}C_D - \lambda_2(t)A_2\delta K_1{}^{\gamma}D^{\delta-1} = 0 \qquad (4\text{-}8)$$

$$\frac{\partial L}{\partial N} = -e^{-it}C_N - \lambda_1(t)nA_1K_2{}^{m}N^{n-1} = 0 \qquad (4\text{-}9)$$

$$\frac{\partial L}{\partial K_2} - \frac{d}{dt}\left(\frac{\partial L}{\partial \dot K_2}\right) = -\lambda_1(t)mA_1K_2{}^{m-1}N^n - \frac{d}{dt}\lambda_2(t) = 0 \qquad (4\text{-}10)$$

$$\frac{\partial L}{\partial K_1} - \frac{d}{dt}\left(\frac{\partial L}{\partial \dot K_1}\right) = -\lambda_2(t)A_2\gamma K_1{}^{\gamma-1}D^{\delta} - \frac{d}{dt}\lambda_3(t) = 0 \qquad (4\text{-}11)$$

$$\frac{\partial L}{\partial \lambda_1} = Q - A_1K_2{}^{m}N^{n} = 0 \qquad (4\text{-}12)$$

$$\frac{\partial L}{\partial \lambda_2} = \dot K_2 - A_2K_1{}^{\gamma}D^{\delta} + Q = 0 \qquad (4\text{-}13)$$

$$\frac{\partial L}{\partial \lambda_3} = \dot K_1 - A_3E^{\alpha} = 0 \qquad (4\text{-}14)$$

3. Derivation of the Estimating Equations:[11]

The above equations, (4-6) through (4-14) are nine equations in nine unknowns Q, E, D, N, K_1, K_2, λ_1, λ_2, λ_3. Equations (4-10) and (4-11) define the optimal paths for $\dot{K}_1$ and $\dot{K}_2$. Using all these equations we solve for λ_1, λ_2, λ_3 and E, D and Q. The final solutions[12] are given as follows:

$$\lambda_1 = \frac{-e^{-it}(a-i)P}{(a+\mu-i)} \tag{4-15}$$

$$\lambda_2 = \frac{-\mu e^{it}P}{(a+\mu-i)} \tag{4-16}$$

$$\lambda_3 = \frac{-\ \delta-1}{\delta^{(\delta/(\delta-1))}}\left[\frac{\mu^{-1/(\delta-1)}(a+\mu-i)^{1/(\delta-1)}\gamma P^{-1/(\delta-1)}C_D^{\delta/(\delta-1)}e^{-it}}{\delta(b-i)-a+i}\right] \tag{4-17}$$

$$E = \left[\frac{\delta^{(\delta-1)}C_E(b\delta-a-i(\delta-1))}{\alpha\mu^{-1/(\delta-1)}(a+\mu-i)^{1/(\delta-1)}\gamma P^{-1/(\delta-1)}C_D^{\delta/(\delta-1)}}\right]^{1/(\alpha-1)} \tag{4-18}$$

$$D = \left\{\frac{e^{-it}C_D(a+\mu-i)}{[\delta K_1{}^{\gamma}(\mu e^{-it}P)]}\right\}^{1/(\delta-1)} \tag{4-19}$$

$$Q = A_1^{-1/(m-1)}K_2^{-m/(m-1)}\left\{\frac{e^{-it}C_N(a+\mu-i)}{n[e^{-it}(a-i)P]}\right\}^{n/(m-1)} \tag{4-20}$$

where

$$\mu = mA_1^{1/m}\left[\frac{Q^{m-1}}{N^{-n}}\right]^{1/m}$$

We impose the following restrictions on the parameters:

(1) $A_1 \geq 0$ as the output cannot be negative;

(2) $d \geq 1$ inasmuch as the second order conditions for profit maximization require that the transformation function be concave.

(3) $0 \leq \beta \leq 1$ according to the standard normalization condition for the CET function[13];

(4) The standard conditions for non-increasing returns to scale require that $m+n \leq 1$, $\gamma+\delta \leq 1$, and $\alpha \leq 1$. The conditions for marginal products to be non-negative require that $\alpha \geq 0$, $\gamma \geq 0$, $\delta \geq 0$, $m \geq 0$ and $n \geq 0$. Together these conditions imply that $0 \leq \alpha \leq 1$ $0 \leq \gamma \leq 1$, $0 \leq \delta \leq 1$, $0 \leq m \leq 1$ and $0 \leq n \leq 1$[14].

In the above system of equations, λ_1, λ_2 and λ_3 are the three shadow prices. λ_1 measures the opportunity cost of producing the resource now instead of in the future. λ_2 measures the opportunity cost of converting an additional unit of probable reserves to proved reserves. It thus reflects the cost of replacing a unit of proved reserves that has been produced. Finally, λ_3 is the opportunity cost of generating an additional unit of probable reserves. Alternatively λs can also be said to measure the present value of the profits foregone in the future (λ_1), or the present value of costs incurred in the future (λ_2, λ_3). Since the present value depends on a whole series of future prices and costs, λ_1, λ_2, and λ_3 also depend upon future prices and costs.

As we are concerned with determining the effects of various variables on exploration, development and production and hence with estimating the elasticities of response to various elements of these three activities, we estimate equations (4-18), (4-19) and (4-20). These three equations define the relationship between the various exogenous variables, (for example prices, cost, interest rates etc.) and exploration, development and production activity respectively. Note that although an estimable expression for N is derived, N is not estimated in the present analysis. Instead, N is substituted in to (4-12) to obtain an estimable equation for Q. (The reader is referred to Appendix B). Note that we now break the composite price of oil and gas (P) into its two components P_{oil} and P_{gas}.[15] Taking logarithms on both sides of these three equations we obtain the equations in estimable form as given below: (for detailed derivations the reader is referred to Appendix B)

For exploration activity the equation becomes

$$\begin{aligned} \text{Log } E = a_0 &+ a_1 \log C_E + a_2 \log [\,\mu - \log (a + \mu - i)] \\ &+ a_3\, i + a_4 \log P_{oil} + a_5 \log P_{gas} \\ &+ a_6 \log C_D \qquad (4\text{-}21) \end{aligned}$$

The signs of the regression coefficients in (4-21) above and in (4-29), (4-34) and (4-35) below depend on the values of the parameters such as α, γ

δ , and β, m, n, ϕ, ψ, and d. Note that ϕ and ψ are the share parameters of P_{oil} and P_{gas} in the composite price P with $\phi \geq 0$ and $\psi \geq 0$. The signs of the estimated coefficients are as follows:

$$a_0 = \frac{1}{\alpha-1}\left[\left(\frac{\delta}{\delta-1}\right)\log\delta - \log\left(\frac{\delta b-a}{\delta-1}\right) - \log\alpha - \log\gamma\right] \tag{4-22}$$

and $$a_1 = \frac{1}{\alpha-1} < 0 \tag{4-23}$$

$$a_2 = \frac{1}{(\alpha-1)(\delta-1)} > 0 \tag{4-24}$$

$$a_3 = \left[\frac{(-\delta-1)}{\alpha-1}(b\delta-a)\right] \gtrless 0 \text{ iff } b\delta \gtrless a \tag{4-25}$$

$$a_4 = \frac{\phi}{(\alpha-1)(\delta-1)} > 0 \tag{4-26}$$

and $$a_5 = \frac{\psi}{(\alpha-1)(\delta-1)} > 0 \tag{4-27}$$

Lastly,

$$a_6 = \frac{-\delta}{(\alpha-1)(\delta-1)} < 0 \tag{4-28}$$

The above are seven equations (4-22 - 4-28) in seven unknowns α, γ, δ , ϕ, ψ, a and b, and therefore can be solved to obtain unique values of these unknown parameters.

For development activity the equation in estimable form becomes:

$$\begin{aligned} \text{Log } D = b_0 &+ b_1 [\log C_D - \log\mu + \log(a+\mu-i)] \\ &+ b_2 \log k_1 + b_3 \log P_{oil} \\ &+ b_4 \log P_{gas} \end{aligned} \tag{4-29}$$

The estimated coefficients have the following signs:

$$\text{if } \delta < 1, \text{ then } b_0 = -\frac{1}{\delta-1}[\log \delta] > 0 \qquad (4\text{-}30)$$

$$b_1 = \frac{1}{\delta-1} < 0 \qquad (4\text{-}31)$$

$$b_2 = \frac{-\gamma}{\delta-1} > 0 \qquad (4\text{-}32)$$

$$b_3 = \frac{-\phi}{\delta-1} > 0 \qquad (4\text{-}33)$$

$$\text{and } b_4 = \frac{-\psi}{\delta-1} \qquad (4\text{-}34)$$

Again, the above are five equations (4-30 - 4-34) in five unknowns ϕ, γ, δ, α, and ψ.

For production activity, the equations in estimable log form for each of oil and gas production taken separately become:

$$\begin{aligned}\text{Log } Q_{Oil} = c_0 &+ c_1 [\log C_N + \log (a + \mu - i) - \log (a-i)] \\ &+ c_2 \log K_2 + c_3 \log P_{oil} + c_4 \log P_{gas} \\ &+ c_5 \log Q_{gas} + c_6 [\log Q_{oil} - \log Q_{gas}]^2 \\ &+ c_7 \log MDP\end{aligned} \qquad (4\text{-}35)$$

$$\begin{aligned}\text{Log } Q_{Gas} = d_0 &+ d_1 [\log C_N + \log (a + \mu - i) - \log (a-i)] \\ &+ d_2 \log K_2 + d_3 \log P_{oil} \pm d_4 \log P_{gas} \\ &+ d_5 \log Q_{oil} + d_6 [\log Q_{oil} - \log Q_{gas}]^2\end{aligned} \qquad (4\text{-}36)$$

The estimated coefficients have the following signs:

$$c_0 = -\frac{1}{\beta(n-1)}[\log A + \log n] > 0 \qquad (4\text{-}37)$$

$$c_1 = \frac{-n}{\beta(n-1)} < 0 \qquad (4\text{-}38)$$

$$c_2 = \frac{-m}{\beta(n-1)} > 0 \qquad (4\text{-}39)$$

$$c_3 = \frac{-n\phi}{\beta(n-1)} > 0 \qquad (4\text{-}40)$$

$$c_4 = \frac{-n\psi}{\beta(n-1)} > 0 \qquad (4\text{-}41)$$

$$c_5 = \frac{-(1-\beta)}{\beta} > 0 \qquad (4\text{-}42)$$

$$c_6 = d(1-\beta) > 0 \qquad (4\text{-}43)$$

And,

$$d_0 = \frac{-1}{(1-\beta)(n-1)}[\log A_1 + \log n] > 0 \qquad (4\text{-}44)$$

$$d_1 = \frac{n}{(1-\beta)(n-1)} < 0 \qquad (4\text{-}45)$$

$$d_2 = \frac{-m}{(1-\beta)(n-1)} > 0 \qquad (4\text{-}46)$$

$$d_3 = \frac{-n\phi}{(1-\beta)(n-1)} > 0 \qquad (4\text{-}47)$$

$$d_4 = \frac{-n\psi}{(1-\beta)(n-1)} > 0 \qquad (4\text{-}48)$$

$$d_5 = \frac{-\beta}{(1-\beta)} < 0 \qquad (4\text{-}49)$$

$$d_6 = d(1-\beta) > 0 \qquad (4\text{-}50)$$

Since (4-37 - 4-43) and (4-44 - 4-50) are each seven equations in seven unknowns β, m, n, ϕ, ψ, d and A_1, each of the two equations is identifiable.

Although each of the equations seperately yields unique parameter values, let us see if the system as a whole is identifiable. In order to do that, we apply the order condition and rank condition to detect identification of the equations. The order condition of identification is a necessary condition but the rank condition is both a necessary and sufficient condition of identification. According to the order condition all equations (4-21, 4-29, 4-35 and 4-36) are over identified. Over-identification of these equations implies that we will obtain more than one value of the structural parameters (m, n, d, α , β , γ , δ , ϕ ψ) being estimated in the model. According to the rank condition equations (4-21) and (4-29) are identified and equations (4-35) and (4-36) are not identified. However, because all four equations satisfy the order condition, the parameters in the model are still estimable[16].

Moreover, with the modifications introduced in the next section of this chapter, equation (4-36) is also identified. Further with changes introduced in Chapter V, (Q_{gas} and Q_{oil} on the right hand side of equations (4-35) and (4-36) are replaced by Q_{gas} and Q_{oil} respectively), equation (4-35) is also identified.

Because the equations are over-identified we will not obtain unique values of the structural parameters. For example, we would obtain four values of and ψ , from four individual equations and two values of β , m, n, α , γ and δ . This problem could be solved by estimating these equations simultaneously with equity restrictions imposed on the parameters. For example, the value of ϕ obtained from each of the four equations should be equal. Similarly, the values of m, n, d, α, γ, δ β, d obtained from various equations should also be equal. Estimating the model with these equality restrictions would yield unique values of these parameters for the entire model.

The regression coefficients of the log-linear equations (4-21), (4-29) (4-35) and (4-36) yield elasticities with respect to various exogenous variables. The elasticities of all variables except μ and i, are equal to their respective regression coefficients. Elasticities of μ - the labour productivity, and i - the interest rates are, however, derived through further calculations involving the regression coefficients and the values of μ and i themselves. These elasticities are calculated as follows:

$$\frac{\partial \log E}{\partial \log \mu} = \frac{1}{(\alpha-1)(\delta-1)} \left(1 - \frac{\mu}{a+\mu-i}\right)$$

$$\frac{\partial \log E}{\partial \log i} = \frac{1}{(\alpha-1)(\delta-1)} \left(\frac{i}{a+\mu-i}\right) - \frac{\delta-1}{(\alpha-1)(b\delta-a)}(i)$$

$$\frac{\partial \log D}{\partial \log \mu} = \frac{1}{\delta-1} \left(\frac{\mu}{(a+\mu-i)} - 1\right)$$

$$\frac{\partial \log D}{\partial \log i} = - \frac{1}{\delta-1} \left(\frac{i}{a+\mu-i}\right)$$

$$\frac{\partial \log Q}{\partial \log \mu} = \frac{n}{n-1} \left(\frac{\mu}{a+\mu-i}\right)$$

$$\frac{\partial \log Q}{\partial \log i} = \frac{n}{n-1} \left(\frac{i}{(a+\mu-i)} + \frac{i}{a-i}\right)$$

Each of the above expressions incorporates the effects of success parameters in both exploration and development (α and δ), productivity of the variable input in the production phase (μ), the discount rate (i) and the rate of nominal output price inflation (a) and the rate of nominal input price inflation (b). Thus it can be seen that the elasticities of E, D, and Q activity with respect to μ and i are determined in a complex fashion by the above parameters and variables (m, n, i, μ , α , δ , ϕ , ψ , β).

4. Modifications

An ideal model should take into account the peculiar characteristics of the industry in question, but often the actual model, in the interests of simplicity and manageability, fails to incorporate all important variables. Such is also true of the model developed in this thesis. It is a partial equilibrium micro model and because it is not embedded in a macro framework, it is unable to effectively capture inter-industry and inter-regional interactions. These interactions may affect the investment decisions in any particular industry. For example, an investor in the oil and gas industry would weigh the rate of return in the oil and gas industry with the rate of return in other industries. In other words, the investor is concerned with the rate of return on investment in the oil and gas industry versus the opportunity cost of that investment, which could be measured by the discount rate i. Alternatively, he may weigh the opportunities in similar industries but in different regions both domestically and abroad. However, the discount rate i as measured in this thesis is unable to capture the opportunity cost of investment in other regions. Further, some regulatory or institutional factors unique to the industry in question cannot be modelled within a restrictive profit maximization framework without affecting the ease of estimation. We thus modify the model slightly to incorporate the effect of some relevant but so far omitted variables. The present section offers an explanation for introducing each of these new variables. The period of estimation of the model is 1960 - 1979 (1965 - 1979 for disaggregated data) and therefore only variables of importance in this period are chosen.

First, equation (4-21) (exploratory footage drilled) is modified to include an independent variable representing the relative price of oil in Alberta vis-a-vis the price in the U.S.A. (Another relative price variable comparing the price of oil in Alberta vs the World price is also experimented with. For calculation of this variable, the reader is referred to Appendix A). Given the fact that exploration and development are essentially investment decisions, and that the majority of the firms operating in the oil and gas industry are multinationals with relatively unfettered opportunities to invest elsewhere, such a variable might well figure prominently in an investment location decision. Assuming the firms operate with budget constraints, the firms involved in exploration and development activities will be concerned with maximizing profits on prospects not only in Alberta but also in other regions or countries. Given the geology of alternative locations, the relative rate of prospective (after-tax) return on similar projects in other countries could affect activity levels in Alberta. Thus we argue that the higher the prospective rate of return in Alberta vis-a-vis other world locations, the higher the footage likely to be drilled in Alberta. The most appropriate variable to measure this effect would be an after-tax rate of return on investment activities in Alberta vis-a-vis a similarly defined after-tax rate of return on industry investment elsewhere. But the tax structure is very complex and an accurate measurement of taxes requires detailed study of tax systems in other countries. This, however, is outside the scope of the present study. We thus take the wellhead price of oil in Alberta relative to the wellhead price of oil in the U.S. ($RP_{oil\ U.S.}$) as our proxy variable.

Equation (4-29) (development footage drilled) is modified to incorporate the variable $RP_{oil\ U.S.}$ as above, and also a variable reflecting the influence of market demand prorationing (MDP)[17]. The arguments for introducing $RP_{oil\ U.S.}$ are similar to those advanced above. We assume that an oil and gas firm faces liquidity constraints not just at the exploration phase, but also in the development phase. In this phase, the exploratory expenditures have been made, but the firm still faces a choice of whether or not to continue investing. One of the factors that may affect the firm's decision is $RP_{oil\ U.S.}$. If the relative price of oil in Alberta is higher than that in the U.S. the firm may accelerate development and ultimately production. However, if the relative price is lower in Alberta, then the firms may restrict development investment.

MDP is a constraint imposed by the government to ensure a prorated share of the current market for domestic oil to all producing wells[18]. This variable, insofar as it restricts the amount operators can produce from each well, could act as a disincentive to building or replacing reserve inventory, and perhaps especially the inventory of proven reserves. However, the negative impact of MDP on development activity is subject to the effects of the well-spacing regulations in the Province. To elaborate, when the MDP quota is binding, then in regions where there is little activity, and room for further drilling (given the well spacing regulations), the firms may tend to drill more wells to achieve a larger share of the market. That MDP may have lead to excessive drilling during the initial phases of development of pools is also illustrated by AERCB (1983) (more details are provided in Chapter V). Thus the negative effect of MDP would be reduced. In regions where activity has been concentrated heavily in the past, the MDP would continue to generate a negative effect. Thus the older (or mature) regions in the province are heavily penalized by MDP both directly by cutting down the output that the firms can actually produce, and indirectly, through reductions in allocated quota resulting from increased drilling in newer areas.

We take excess capacity for oil, i.e. a ratio of maximum productive capacity in Alberta to actual production, as the relevant proxy variable for MDP. Both the productive capacity and actual production are measured in cubic metres per year. Given other variables, we postulate that the higher the excess capacity in the previous year, the lower will be the development footage drilled this year.

Finally, equation (4-35), (Q_{oil}) is modified to incorporate MDP. It is postulated that the more restrictive the effect of market demand prorationing or level of excess capacity per producing well, the lower would be the production. Although MDP imposes a more direct constraint on production (than development), so much so that if binding output may be exogenous, in cases where the optimal production level (imposed through the production constraint) is less than the market allowable quota, MDP may not be a binding constraint. As MDP is measured by lagged excess capacity, we hypothesize that the restrictive trends as evident in the previous year would continue, and these would generate a negative impact on today's production levels. Note that because the proxy for MDP is a lagged variable, the one-to-one correspondence that may be evident in the case of MDP being a binding constraint is eliminated. We do not modify equation (4-36).

Since the equations (4-21), (4-29), (4-35) and (4-36) are log-linear, we assume that the new variables also enter the equations in logarithmic form. This form has an advantage of yielding the elasticities directly from the regression coefficients. Thus, the modified equations are given as follows:

$$\text{Log } E = a_0 + a_1 \log C_E + a_2 [\log \mu - \log (a + \mu - i)] + a_3 i + a_4 \log P_{oil} + a_5 \log P_{gas} + a_6 \log (i) + a_7 \log RP_{oil\ U.S.} \tag{4-51}$$

$$\text{Log } D = b_0 + b_1 [\log C_D - \log \mu + \log (a + \mu - i)] + b_2 \log K_1 + b_3 \log P_{oil\ U.S.} + b_4 \log p_{gas} + b_5 \log MDP + b_6 \log RP_{oil\ U.S.} \tag{4-52}$$

$$\text{Log } Q_{Oil} = c_0 + c_1 [\log C_N + \log (a + \mu - i) - \log (a-i)] + c_2 \log K_2 + c_3 \log P_{oil} + c_4 \log P_{gas} + c_5 \log Q_{gas} + c_6 [\log Q_{oil} - \log Q_{gas}]^2 + c_7 \log MDP \tag{4-53}$$

5. Policy Instruments and Implications

The instruments of public policy dealt with in this study are the prices of both oil and gas, market demand prorationing, royalties, corporate income tax, and the various tax concessions available to the oil and gas industry. Market demand prorationing enters the above framework directly, while the other tax parameters enter through the net prices or effective costs. The exact formulation of the netback prices and effective cost utilized in this study is as follows:

$$P_{oil} = [1 - R_o]\, WP_{oil} - T_{oil}$$

$$P_{gas} = [1 - R_g]\, WP_{gas} - T_{gas}$$

$$C_E = [1 - \tau(\gamma_E) - \tau(DE)]\, AC_E$$

$$C_D = [1 - \tau(\gamma_D) - \tau(DE)]\, AC_D$$

$$C_N = [1 - \tau(1 - RA)]\, AC_N$$

In the above equations,

WP_{oil} is the wellhead per barrel price of oil

WP_{gas} is the wellhead per Mcf price of gas

AC_E is the actual per foot cost of exploration

AC_D is the actual per foot cost of development

AC_N is the actual operating cost per '000 BTU of oil and gas

R_O is an average % rate of royalty on per barrel wellhead price of oil

R_G is an average % rate of royalty on per Mcf wellhead price of gas

τ is the corporate income tax rate per \$ of income

γ_E is the % exploration expenditure writeoff rate on cost per foot

γ_D is the % development expenditure writeoff rate on cost per foot

DE is the % earned depletion allowance on cost per foot of exploration and development

RA is the resource allowance rate on \$ of resource profit.

T_{oil} and T_{gas} are the provincial and municipal taxes excluding the corporate income tax, paid by the oil and gas industry, per barrel and per Mcf produced.

To calculate T_{oil} and T_{gas}, we first calculate the average tax paid per m^3 of oil or gas. Then for oil, we convert it to tax paid per barrel and for gas we convert it to tax paid per '00 Mcf (one hundred thousand cubic feet). As can be seen from the equations in the begining of this section, P_{oil} and P_{gas} are the netback prices of oil and of gas, (i.e. net of royalties on oil and gas and taxes other than income tax) and C_E, C_D are respectively the per foot effective cost of exploration and development, and C_N the effective operating cost per '000 BTU of oil and gas.

Note that the above accounting relationships apply to firms that have a taxable income. If a firm has no taxable income it cannot make use of the depletion allowance or the exploratory and development writeoff allowances. However, the firms can carry forward any available writeoffs against future profits.

To derive policy implications from our behavioral model (4-51, 4-52, 4-53, 4-36), let us first look at the elasticities of independent variables (P_{oil}, P_{gas}, C_E, C_D, C_N) with respect to the policy parameters (R_O, R_G, DE, RA, γ_D, γ_E). From the above equations, the elasticity of P_{oil} with respect to R_O ($\eta_{Poil,\ RO}$) equals,

$$\eta_{Poil,\ Ro} = -\frac{(WP_{oil} \times RO)}{Poil}$$

Thus a change of s% in R_O will lead to a change of ($.s \times \eta_{Poil,\ RO}$) in P_{oil}. By similar logic, a change of r% in R_g will lead to a change of ($.r \times \eta_{Pgas,\ Rg}$) in P_{gas}.

Elasticities of various costs with respect to changes in different policy parameters are as follows:

$$\eta_{CE,\,DE} = -\frac{\tau \times DE \times AC_E}{C_E};$$

$$\eta_{CD,\,DE} = -\frac{\tau \times DE \times AC_D}{C_D};$$

$$\eta_{CN,\,RA} = -\frac{\tau \times RA \times AC_N}{C_N};$$

$$\eta_{CE,\,\gamma E} = -\frac{\tau \times \gamma_E \times AC_E}{C_E};$$

$$\eta_{CD,\,\gamma D} = -\frac{\tau \times \gamma_D \times AC_D}{C_D}.$$

Given the above elasticities, the effect of change in any one or more of the policy parameters on various activities (E, D, Q_{oil}, Q_{gas}) can easily be demonstrated. These are discussed briefly in the following.

<u>(a) Induced Effects of Changes in Policy Instruments on Exploratory Activity</u>: Equation (4-51) is as follows:

$$\text{Log } E = a_0 + a_1 \log C_E + a_2 [\log \mu - \log (a + \mu - i)] + a_3 i + a_4 \log P_{oil} + a_5 \log P_{gas} + a_6 \log (i) + a_7 \log RP_{oil\ U.S.} \qquad (4\text{-}51)$$

a_1 through a_7 are the various elasticities of exploratory activity.

The effect of change in R_0 on exploratory activity can simply be given as

$$\eta_{E,\ RO} = a_4 \times \eta_{Poil,\ RO}$$

and a change of s% in R_0 will lead to a change of $(.s \times \eta_{E,\ RO})$ in exploratory activity. Similarly, the effect of change in DE on exploratory activity will equal

$$\eta_{E,\ DE} = a_1 \times \eta_{CE,\ DE} + a_6 \times \eta_{CD,\ DE}$$

and a s% change in DE will lead to $(.s \times \eta_{E,\ DE})$ change in exploratory activity.

(b) Induced Effects of Changes in Policy Instruments on Development Activity: Similar effects of the various public parameters on development activity can be analyzed as follows:

$$\begin{aligned} \text{Log } D = b_0 &+ b_1 [\log C_D - \log \mu + \log (a + \mu - i)] \\ &+ b_2 \log K_1 + b_3 \log P_{oil\ U.S.} + b_4 \log p_{gas} \\ &+ b_5 \log MDP + b_6 \log RP_{oil\ U.S.} \end{aligned} \tag{4-52}$$

As for exploration, the effect of change in R_0 on development activity can be given as

$$\eta_{D,\ RO} = b_3 \times \eta_{Poil,\ RO}$$

and a change in DE as

$$\eta_{D,\ DE} = b_2 \times \eta_{CD,\ DE}$$

(c) Induced Effects of Changes in Policy Instruments on Production:

$$\begin{aligned}\text{Log } Q_{oil} = {} & c_0 + c_1 [\log C_N + \log (a + \mu - i) - \log (a-i)] \\ & + c_2 \log K_2 + c_3 \log P_{oil} + c_4 \log P_{gas} \\ & + c_5 \log Q_{gas} + c_6 [\log Q_{oil} - \log Q_{gas}]^2 \\ & + c_7 \log MDP\end{aligned} \quad (4\text{-}53)$$

$$\begin{aligned}\text{Log } Q_{gas} = {} & c_0 + c_1 [\log C_N + \log (a + \mu - i) - \log (a-i)] \\ & + c_2 \log K_2 + c_3 \log P_{oil} + c_4 \log P_{gas} \\ & + c_5 \log Q_{oil} + c_6 [\log Q_{oil} - \log Q_{gas}]^2\end{aligned} \quad (4\text{-}36)$$

The effect of change in R_0 on production of oil can be given as

$$\eta_{Qoil,\ RO} = c_3 \times \eta_{Poil,\ RO}.$$

and a change in RA as

$$\eta_{Qoil,\ RA} = c_1 \times \eta_{CN,\ RA}.$$

Similarly, the effect of change in R_G on production of gas can be calculated as

$$\eta_{Qgas,\ RG} = d_3 \times \eta_{Poil,\ RG}$$

and a change in RA as

$$\eta_{Qgas,\ RA} = d_1 \times \eta_{CN,\ RA}$$

Relative Effects of Policy Parameters on Exploration, Development and Production.

As a matter of further interest, let us consider the effect of a change in the same policy parameter on changes in three activities. This will depend upon the relative elasticities of E, D, Q_{oil}, and Q_{gas} with respect to the independent variable in which the policy parameter enters (see equations 4-22 - 4-28, 4-30 - 4-34, 4-37 - 4-50 at the beginning of this section).

Comparing the elasticities of E, D, and Q_{oil} with respect to R_O, we can see that

$$\eta_{E,\ RO} > \eta_{D,\ RO} > \eta_{Qoil,\ RO}$$

iff $\alpha > 0$, and $\delta < [1 + \beta(n - 1)/n]$

If these two conditions are met, a change in R_0 will effect exploratory activity the most. Production will have the least effect.

Similarly, the effect of a change in DE on exploration will be larger than the effect of a similar change on development i.e.,

$$\eta_{E,\,DE} > \eta_{D,\,DE}$$
$$\text{iff} -\alpha\,\eta_{CD} > (\delta - 1)\,\eta_{CE}.$$

Considering the nature of the industry, such relative elasticities are hardly surprising. As noted above, exploration is the riskiest of all phases of the petroleum industry, and involves large outlays. Therefore, the firms are quite sensitive to changes in prices or costs. Once in development phase, the firms are sensitive to prices and costs but to a lesser degree, as large investments have already been made in the first phase and this will restrict their sensitivity to changes in prices or costs. Finally, in the production phase, where marginal costs are small in comparison with large sunk costs, the firms are relatively insensitive to changes in prices and costs.

6. Alternative Exploration Sub-Model

The model outlined above is derived as a problem in profit maximization taken across all activity phases of the industry. It is restrictive in that only such variables that fit into a profit maximization framework are incorporated. In this section, we formulate an alternative sub-model of investment, which emphasizes exploration as the key element of the oil and gas industry. Implicitly, it assumes that the decision-making takes place in the first phase where the investors weigh the economic incentives, geological characteristics, and the institutional structure of the oil and gas industry. This sub-model then assumes that the prime concern of the investors is to generate reserves through exploration. Once exploratory outlays have been made in the oil and gas industry, development and production follow.

The structure of this model is simplistic. It is an open model in that it is not constrained by a profit maximization framework. Three equations based on a priori understanding of the industry are specified. As is evident from the review section, these types of models have been quite popular in energy economics. The obvious reason is, that the complexity of the resource industry makes it difficult to model the various activities in a realistic manner. Being an ad hoc specification (see Chapter III, section 2.a), the model in this section resembles some of the earlier work done in this area (Fisher 1964, Erickson and Spann 1971, MacAvoy and Pindyck 1973).

The first component of this three equation model explains the extent of exploratory activity in terms of the price of oil in Alberta relative to that in the U.S., the expected profitability in the oil and gas industry, the rate of return in alternative industries, the level of retained earnings in the oil and gas industry, and the number of acres held (both newly acquired and old) under the various regulatory arrangements. In the second equation, the expected profitability in the oil and gas industry is further defined by an expected success ratio, the expected wellhead price of oil, the expected wellhead price of gas and the expected cost per foot of exploration and development. We assume that expectations are formed on the basis of past experiences. Specifically, expectations are assumed to equal the weighted average of past experiences where higher weights are assigned to more recent experiences.

Note that as opposed to the previous model, prices and costs do not directly affect exploratory activity; rather, the effect is indirect - through expectations of profitability. Expected rather than actual netback prices are hypothesized to affect the decision-making process.

The third equation in this model explains the success ratio in exploration as a function of the level of undiscovered reserves. The undiscovered reserves are defined as that portion of the resource which is inferred to exist on the basis of general geological interpretation, but not yet discovered and classified as either probable or proved reserves.

The model is thus written as

$$\text{Log } E = e_0 + e_1 \log RP_{\text{oil U.S.}} + e_2 \log ExP + e_3 \log RP_{alt} + e_4 \log RE_{t-1} + e_5 \log L \quad (4\text{-}54)$$

$$\text{Log } ExP = f_0 + f_1 \log \hat{SU}_E + f_2 \log \hat{P}_{oil} + f_3 \log \hat{P}_{gas} + f_4 \log \hat{C}_{E+D} \quad (4\text{-}55)$$

$$\text{Log } SU_E = g_0 + g_1 \log UDR \quad (4\text{-}56)$$

where ExP is the expected profitability of producing oil and gas;

RP_{alt} is the relative rate of return in alternative industries;

RE_{t-1} is the absolute level of retained earnings in the oil and gas industry in the previous year;

L is the total number of acres held under the various regulatory provisions.

$\hat{SU}_E$ is the expected success ratio in exploration.

$\hat{P}_{oil}$ is the per barrel expected wellhead price of oil

$\hat{P}_{gas}$ is the expected wellhead price of gas per Mcf

$\hat{C}_{E+D}$ is the expected cost per foot of exploratory and development drilling.

and UDR is the level of undiscovered reserves.

The first of the variables in equation (4-54) is the same as that used in equation (4-51) in the previous section. It measures the relative attractiveness of the investment of the expected price regime in Alberta vis-a-vis other regions (U.S.). As the mobility of capital is high between Canada and U.S., and as the firms involved are mainly multinationals, they have a choice of investing in Alberta or elsewhere. Their choice to some extent depends upon the relative after-tax rate of return in various regions. As explained in the previous section, in the absence of accurate measures of taxes in other regions, we use the wellhead price of oil in Alberta relative to that in U.S. as a proxy variable for the relative attractiveness of the Alberta oil and gas industry. We hypothesize that the higher the wellhead price of oil in Alberta relative to U.S., the higher will be the exploratory activity.

The second of the variables in equation (4-53) is used as a measure of the expected profitability in the oil and gas industry. Bonus bids paid per acre in a given geological region in any given time period are taken to be a proxy for expected profitability and it is these annual payments which are used to define EXP. While making a bid, the investor is concerned primarily with two factors - first, the discovery prospects on that tract which can be represented by an expected success ratio measured in terms of the ratio of successful to total wells in that tract. Second, the financial return that they can achieve on the output from that tract - this is influenced by the expectations of future prices and costs.

As mentioned at the beginning of this section, capital is mobile between regions as well as between industries, and therefore the investor is faced not only with a choice of regions in which to invest, but also a choice of industries. We hypothesize that when considering an investment in the oil and gas industry, the investor compares the rate of return in alternative industries. We thus take an average return in seven industry groups which include total mining, primary metals, metal fabrication, non-metallic mineral products, petroleum and coal products, chemical products and public utilities.

Even if there is a higher expected profitability and higher relative rate of return in the Alberta oil and gas industry vis-a-vis other regions and other industries, industry activity may nevertheless be constrained by the amount of capital available and by the amount of land available for acquisition. Of these two constraints, the first is a liquidity constraint - the extent of liquid assets available for investment. Although it is recognized that debts do form an important part of the capital structure, we take the retained earnings generated each year in the oil and gas industry as a proxy for available capital. Implicitly we assume that because exploration is risky, debt availability is restricted. Evidence from the petroleum industry in the last few years supports our assumption. The proportion of investment funded by debt in this industry is much lower than that in other industries. In 1981, 1982 and 1983, the industry funded 39%, 38%, and 37%[19] respectively of its investment from long term debt. For all industries considered together, the ratio of debt-financed investment for these years was 45%, 46% and 46% [20] respectively. For utilities, this ratio is much higher - for 1981, 1982 and 1983, it remained constant at 64%. In previous years, evidence suggests that the ratio of debt-financed investment was even lower. For example, in 1974 this ratio was 16.6%[21].

Retained earnings are measured by the undistributed after-tax profits in the oil and gas industry. We hypothesize a lagged relationship - the higher the level of the earnings retained in the last year, the greater the amount of capital available and hence a higher level of investment spending and activity.

The second constraint limits activity to the amount of land held by the industry. As discussed in Chapter II, although the government owns the resource in the province, it relies on the private sector for the development and production of the resource. The private sector obtains a claim on the resource through a system of leases and licences which confer a right to drill as well as to produce. The lease and licences are offered by the government for bids by the private sector. The number of wells that a firm can drill is constrained by the amount of leased land that is held under the various regulatory provisions. We hypothesize that the larger the number of acres held (under various leases and licenses) by the firms, the higher the activity. Note that once the firms acquire a particular piece of land, they are forced to drill within a specific time limit or else their lease/licence is subject to cancellation.

The number of acres held under various leases and licenses is not strictly an exogenous variable. The decision to acquire land indicates an intention to drill. Thus both E and L are governed by similar forces such as the expected profitability and the price of oil in Alberta relative to U.S. Since a separate equation for L is not specified although it is an endogenous variable, there exists some simultaneity bias in the model. This is eliminated by estimating the model through 3SLS.

As mentioned above, expected profitability is influenced by three factors: the discovery prospects (how much is likely to be found and producible from a given investment), the price at which the output can be sold and the unit cost at which it can be produced. Thus in equation (4-55), which purports to explain expected profitability, the independent variables are the expected exploratory success ratio ($\hat{SU}_E$), the expected netback price of oil ($\hat{P}_{oil}$), the expected netback price of gas ($\hat{P}_{gas}$), and the expected unit cost of exploratory and development footage drilled ($\hat{C}_{E+D}$). Each of these four variables is calculated as a weighted average of the three most recent annual values. While current values may be an accurate reflection of producer's expectations of the variables in question, we hypothesize that it is more likely that the expectations are based on the observed pattern of values over several years. (Note while in much of the period under observation, this assumption regarding the expectations formation may be true, in the period between 1974 - 1979, when the prices escalated dramatically, it may not be a valid assumption.) As prices and the success ratio affect revenue and hence profitability, we assume that the higher the netback price of both oil and gas, and the ratio of success, the higher the expected profitability, assuming no other change. Thus $f_1 > 0$, $f_2 > 0$ and $f_3 > 0$. Costs are assumed to have a negative affect on profitability, implying that the higher the unit cost of exploration and development, the lower the expected profitability. Thus $f_4 < 0$. Note the inclusion of development costs. We assume that exploration phase by itself is not sufficient for the production of resource. The resource has to be developed and thus requires significant outlays. Thus the firm in the exploration phase is not only sensitive to costs in that phase, but anticipated costs of developing the resource.

The above equation is simplistic - and the use of aggregated unit bonus bids to depict expected profitability has not been used in previous studies. However, historical trends of bonus bidding indicate that such bids do respond to changes in price, and are sensitive to expectations of success in terms of reserve discoveries. Appendix A provides historical information on bonus bids for individual fields. The data indicate that as fields are discovered and the geology of the field becomes better known (with a resulting increase in the success ratio), the bids per acre increase. Also, the data suggests that bids per acre increase with prices.

Finally, equation (4-56) explains the success ratio in any time period t by the level of undiscovered reserves (UDR). The UDR is defined as that portion of the resource which is inferred to exist but not yet discovered as either probable or proved reserves. It is a given potential which is said to exist and is independent of the effect of prices and costs. UDR is calculated on the basis of such geological information as area of closure and reservoir thickness. (The reader is referred to Appendix A for more details.) Thus, it varies from established reserves or economic reserves which are related to price and costs. For example, in a given region we may assume on the basis of available information that X million cubic metres of oil reserves are located. Now at some given price 10% of this ultimate potential may be economic. If the prices increase, 20% may be economic. However, irrespective of the level of prices, the ultimate potential is constant.

It is hypothesized that the UDR could have a negative or positive effect on the success ratio depending on the phase of exploration. In the initial phase, firms do not have a great deal of information. With further drilling they acquire more knowledge about the geological composition and gradually may tend to drill in areas which produce a relatively higher success ratio. Thus the success ratio may increase in the initial phase. As UDR decreases, in the initial phase $g_1 < 0$. As the tract matures, good prospects are exhausted and the success ratio declines indicating a depletion effect. In this phase of exploration $g_1 > 0$ i.e. with decreases in UDR the success ratio also declines[19].

The discussion to this point has attempted formulations of a supply model for oil and gas, and a variant of that model. The models are estimated for various samples obtained from the Alberta oil and gas industry. The exact procedure of estimation and the results so obtained are illustrated in the following chapter.

Footnotes:

1. Although there are a number of common risks such as political risks, general economic risk, and risks about future oil and gas prices, which have to be borne throughout the exploration and development phase, we here refer to the risks of (a) drilling a dry hole, and (b) a small size of discovery per well. Risk of such kind are not uniform for exploration and development. For example, because exploratory drilling is generally concentrated in newer areas with little knowledge about the geology, location or the size of the resource, the risk of drilling a dry hole or discovering small reserves per well is substantially higher in the exploratory phase. But as the field is developed, drilling is concentrated in better known areas, generating a higher success ratio - both in terms of wet wells discovered and larger size of discovery.

2. See Canadian Petroleum Association, Statistical Handbook, 1976.

3. The production leases in this industry are more often held by the larger firms. They can either do the exploration themselves or let the smaller firms do the exploratory drilling for the lessee. In such a case these firms meet the exploratory costs in exchange for an interest in any later production of oil and gas.

4. For simplicity of exposition, we leave the introduction of royalties, taxes and various writeoff rates until the estimating equations have been derived. Also the per-foot cost of exploration used here is prior to the payment of cash bonuses and rentals paid by the operators.

5. The present thesis does not concern itself with the question of directionality. Thus in the exploration and development phase, we do not distinguish between exploration for oil from that of gas, and development for oil from that of gas. It is only in the production

phase that the two products are seperated.

6. For example the Generalized Leontief (Diewert, 1971, 1973) the Translog (Christensen, Jorgenson and Lau, 1973), the Quadratic (Lau, 1972) and the Generalized Cobb-Douglas (Diewert, 1973).

7. Let $Z(Y, W) = 0$ be a production possibility frontier, where Y is the index of aggregate output and W is the index of aggregate input. Group-wise additivity of the production possibility frontier in the two groups consisting of outputs and inputs implies that the production possibility frontier can be represented by

$$Z(Y) = X(W)$$

The above group-wise additive production function is said to be commodity-wise additive if $Z(Y) = X(W)$ can be represented by

$$[Z(Y_1) + Z(Y_2)] = [X(W_1) + X(W_2)]$$

where Y_1 and Y_2 are the two commodities in the output group and W_1 and W_2 the two commodities in the input group.

A Constant Elasticity of Transformation - Constant Elasticity of Substitution (CET-CES) frontier of the form,

$$[\ \beta_1 Y_1 + (1 - \beta_1)Y_2\ ] = A[\ \beta_2 W_1 + (1 - \beta_2)W_2]$$

is group-wise additive in two mutually exclusive and exhaustive commodity groups, and each group is commodity-wise additive in the two commodities that comprise the groups. The CET-CES function restricts the substitution parameters to two. For (Translog frontier) under homogeneity, symmetry and normalization restrictions, there are five substitution parameters. If group-wise additivity in inputs and outputs is imposed, then the translog frontier would also have two substitution parameters. (For further discussion of Translog production functions, the reader is referred to Christenson, Jorgenson and Lau (1973))

8. There is strong evidence of multicollinearity in these flexible functions. The attempt to deal with this is at the cost of biased estimates, or an ad hoc parameter selection process (Vinod, 1976).

9. Although oil and gas can be both measured in terms of cubic feet (cf) or cubic metres (m^3), the BTU content of a unit of oil (cf or m^3) is different from that of gas. Therefore, when adding the reserves of oil and gas or deriving a composite output (Q), we convert them to a common base in BTU terms. It is assumed that,

1 cf of gas = 1000 BTU of Energy
1 cf of oil = 1000,000 BTU of Energy

This conversion factor is widely used in the industry by geologists and engineers.

Another way of aggregating the reserves of oil and gas is on the basis of their value added. But since in much of the period under consideration, the price of gas was artificially kept below the oil price, the true relative value og gas reserves could not have been obtained.

Perhaps a better way would be to incorporate the reserves of oil and gas as seperate variables in the model. (For example see Epple (1975) in which reserves of oil and of gas are treated as multiple outputs of the exploration process). But this would complicate the functional form of the equations currently derived in the model and make estimation difficult.

10. $\bar{d}$ determines the elasticity of transformation between the production of oil and gas, (i.e. transformation between the two products only at the production stage) $\rho = \frac{1}{d-1}$ which measures the % change in the ratio of output of oil and gas when the level of inputs is held constant.

11. The exact solution is given in Appendix B.

12. The given solution is based on the assumption that the constant of integration in the integral for λ_1 is zero. This assumption is important, for in order to arrive at a solution for E we have to solve for λ_3, and the only way to solve for λ_3 is to assume that the constant of integration, g = 0.

Appendix B gives the exact solution. First λ_1, λ_2, D and Q are solved making no assumption about g. The values of λ_2 and D are then substituted to get an integral for λ_3, which is of the following form

$$[C_1 e^{it} + C_2 e^{ut}]^{C3} dt$$

Note that the solution of this integral is difficult and one way to solve it is to assume that g = 0. Although D and Q can be solved without making this assumption, to be consistent we assume it throughout the model. However, in the next chapter we do test for the empirical implications of this assumption.

13. See Powell and Gruen (1968).

14. These conditions are assumed on the basis of standard economic theory. For details, see Henderson and Quandt (1958).

15. The Composite Price of oil and gas P can be further broken down into separate prices. We assume that $P = P_{oil}{}^{\phi} P_{gas}{}^{\psi}$ where ϕ and ψ are the respective weights of the prices of oil and gas.

16. See Madalla (1977) p 225.

17. MDP could be introduced endogenously in the model through the production function. (See Cox and Wright, 1976). However, such a formulation would generate non-linear equations which are difficult to estimate given high collinearity in our sample data.

18. As MDP restricts supply, under some circumstances it could be used as a tool for a price stabilization policy.

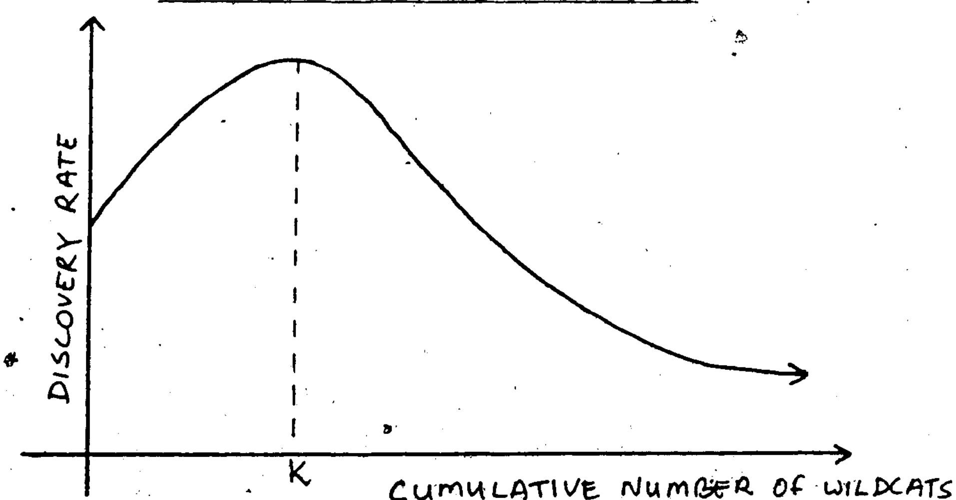
19. Statistics Canada, Corporation Financial Statistics, 61-207, 1981, 1983, Table 2a.

20. Quirin and Kalymon (1977)

21. The relationship captured by equation 1(c) can be compared with that shown by Uhler. Uhler (1976) indicates how the discovery rate could initially increase with the cumulative exploration effort and then decline. We may thus have a relationship as shown below:

Figure 4-1

The Rate of Discovery Function (a)

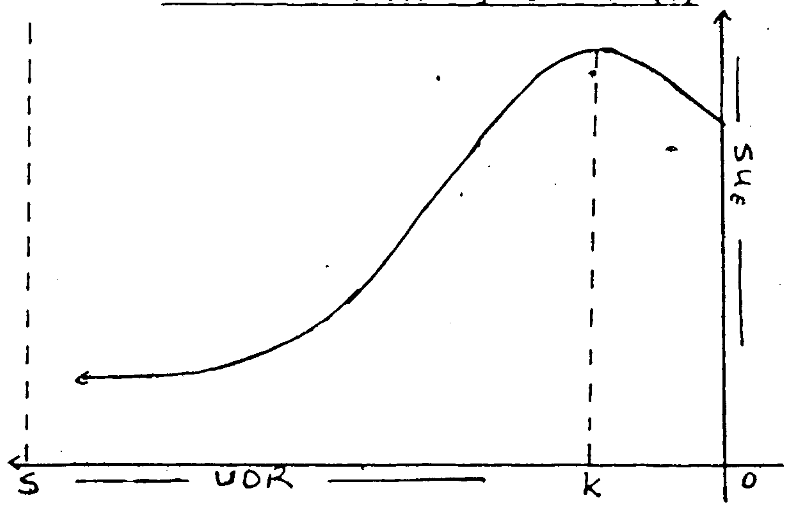


As this figure indicates initially with increases in cumulative effort the discovery rate increases due to the predominance of the geological information effect. (The discovery rate is measured as barrels of oil discovered per exploratory well drilled). But as the cumulative effort increases beyond K, the depletion effect dominates and the discovery rate declines.

In our formulation, UDR is replaced by cumulative number of wells drilled (CWXT). UDR is fixed at the beginning of a discovery at OS. In the earlier stages of a discovery, we assume that the success ratio increases. In the later stages as depletion sets in the sucess ratio declines. But as more and more is discovered, UDR also declines. Thus while UDR declines all through the discovery and development of the resource, the success ratio first increases and then decreases giving rise to a relationship as illustrated in Figure 4-2. In this figure, success ratio (SU_E) is measured on the vertical axis and UDR on the horizontal axis. The curve indicates that as UDR declines, SU_E first increases until K is reached and then declines.

Figure 4-2

The Rate of Discovery Function (b)



Although, theoretically the above curve is fixed for a particular reservoir, empirically this UDR curve may change. This would occur primarily if the UDR estimates change due to better information available on the reservoir.

CHAPTER V: EMPIRICAL RESULTS

The previous chapter formulated two models of the oil and gas industry. The first is a profit maximization model wherein an oil and gas firm maximizes its present value of cash flow subject to certain constraints. Such a maximization yields estimating equations for exploration, development and production. The second model is an exploration investment model - three equations explaining the level of exploration, expected profitability and success ratio in exploration are specified. All the equations from the two models are estimated with various techniques. In this chapter, we report and analyze these empirical results.

The chapter is divided into eight sections. The first discusses the data used in the econometric analyses. The second section outlines the methodology utilized in estimating the two models. The third section provides a brief summary of the overall empirical estimates, with emphasis on several important results. The fourth, fifth and sixth sections respectively incorporate discussions of the results for each of the equations comprising the profit maximization model - i.e., exploration, development and production of oil and gas. The seventh section deals with the results arising from the alternative exploration investment sub-model. The last section compares the results of the profit maximization model with the alternative *a priori* exploration sub-model.

1. The Data.

Details concerning the sources of the data are given in Appendix A. In this section we define the variables and assign their units of measurement. We also illustrate the methods used to construct certain inferred micro data as a substitute for information not directly available through published sources.

The entire data are grouped into four data sets and separate estimation runs are made on each set. Both models are estimated for all four data sets. The first group encompasses information for the province of Alberta as a whole. These data are taken from published sources. They consist of 20 annual observations for the years 1960-1979. For the purpose of forming the second, third and fourth data sets, we take a sample of 15 major oil fields in Alberta, with annual observations of 15 years between 1965 and 1979[1]. Each of the second, third and fourth data sets is defined as follows:

1) The second data set consists of the 15 fields sub-divided into four sub-groups, each sub-group representing fields falling within the four zones of the province (Plains, Central, Northern and Foothills). This

zonal classification is the same as that used by the provincial government's drilling incentive program, and the four zones comprise the entire area of the province. Each of the first three zones include four selected major oil fields, but the last (Foothills) consists of only three major oil fields. The second data set thus has 60 observations for each zone (45 for Foothills), obtained by pooling cross section (4 or 3 fields in each zone) and time series data (15 annual observations).

2) The third data set includes 15 sub-groups referring now to the 15 separate fields carrying 15 annual observations for each.

3) The last data set has 225 observations (15 x 15) obtained by pooling the data across all 15 fields, and all 15 years, from 1965-1979.

<u>(1) The Dependent Variables - E, D, Qoil, Qgas</u>. The data then consist of annual observations on each of the exogenous and endogenous variables included in the two models developed in Chapter IV. Recall that these models have seven equations - four in the profit maximization model and three in the alternative exploration investment sub-model. The first equation in both models explains the same variable (E). Thus we have six dependent variables to be explained in considering the two models together. The first two variables, exploratory drilling activity (E)[2] and development drilling activity (D), are measured in total number of feet drilled per year. The third

and the fourth, the production of oil (Q_{oil}), and the production of gas (Q_{gas}), are measured respectively in cubic metres of oil per year and 10^3 cubic metres of gas per year. The fifth dependent variable, expected profitability (EXP), is measured by proxy via bonus bids paid per acre for the acreage on which the wells are drilled. For each area considered (example - field, zone or province), an average bonus bid is calculated by taking into account all the leases and licences bought over time under the concerned area. The last dependent variable, the success ratio (SU_E), is defined as the ratio of successful exploratory wells to total number of exploratory wells drilled.

(ii) Reserves of Oil and Gas - Probable, Proved and Undiscovered. The reserves of oil and gas - probable, proved and as yet undiscovered - are given in millions of cubic metres. The data on probable (K_1) and proved (K_2) reserves for all Alberta are available through published sources. However, although the proved reserves for each field are given, the probable reserves are not published by field due to confidentiality restrictions. Therefore, to obtain an estimate of the level of annual probable reserves, for each sample field, we first calculated a ratio of probable reserves found per successful exploratory feet drilled for Alberta as a whole for each year. This provincial ratio was then multiplied by the total number of successful exploratory feet drilled in each field to get the total probable reserves for each field, and for each year. A cumulative sum of this yearly data then produces our inferred estimate of the level of probable reserves for each of the fifteen fields included in this study.

Another way of calculating the level of probable reserves would be to take the provicial ratio of probable to proved reserves and apply this ratio to individual fields and zones. In this case we will implicitly assume that "γ" in equation (3) of Chapter IV is the same for all fields, zones and the province. (Recall that "γ" measures the change in proved reserves due to a change in probable reserves). On the other hand in applying the provincial ratio of probable reserves to number of successful exploratory footage, we implicitly assume that a part of "α" in equation (4) of Chapter IV is constant. (Recall that "α" measures the change in probable reserves due to a change in exploration). Since E can be divided into successful and unsuccessful footage, "α" will depend upon two factors: (i) probable reserves additions per successful well and (ii) ratio of successful wells to total exploratory wells. (ii) is available for each field, therefore, by following the first approach we take into account a greater degree of variability (geological and otherwise) between fields and zones.

UDR is defined as the amount of resource in a given area which is presumed to exist but is not yet discovered with any certainty (i.e. cannot be classified as either probable or proved). The UDR estimates for the province are established by the Geological Survey of Canada on the basis of such factors as area of closure, reservoir thickness, and porosity. Note that these estimates are based primarily on geologic rather than economic variables.

The estimates of undiscovered oil and gas reserves (UDR) are expressed in probabilistic terms. Thus we have a UDR estimate with a high (90%) probability, a low (10%) probability and also an estimate with a medium (50%) probability. To evaluate the effect of different levels of UDR on success ratios and ultimately on investment, we use the estimates associated with both the low and the medium probabilities. The UDR estimates for the province are given for a single year (we took the 1977 estimate)[3]. In order to generate data for previous years we added the yearly proved reserves to the 1977 estimate. For example, to obtain the UDR estimate at the begining of 1976, the incremental proved reserves for 1976 were added to the UDR estimates for 1977. Similarly, to get UDR estimates for 1978, the added proved reserves generated in 1977 were subtracted from the UDR estimate of 1977.

Similar data for the fields are not published. However, we calculated (inferred) the UDR for fields from information provided by the Geological Survey of Canada (GSC). The most recent data provided by GSC prior to 1979 (1977) was used. The exact procedure is outlined in Appendix A.

<u>(iii) The Interest Rate</u>. In our analysis we have used several proxies for 'i', i.e. the rate at which anticipated profits are discounted in the present value function. Three alternative proxies for i were

used. First, 'i' for a particular year was defined as the average rate of return on equity in the mining and energy related industries in Canada; second, for the same year, 'i' was taken as the average rate of return on long term capital employed in the mining and energy related industries in Canada for the same year; and lastly, 'i' was calculated as the average yield on the Canadian Government's long term bonds. Particular industries included in the group were total mining, primary metals, metal fabricating, non-metallic mineral products, petroleum and coal products, chemical products and public utilities. The rate of return on equity was calculated by taking a ratio of net profits (including non-recurring items, but excluding interest, depreciation and taxes) to total equity (book value) of shareholders and affiliates, averaged over these seven industry groups. The rate of return on long-term capital employed, on the other hand, was calculated by taking a ratio of after-tax profits, plus non-recurring items to capital, plus interest payments on funded debt, to total long term liabilities plus net worth across the above industrial groups. Both nominal and real interest rates were experimented with. In the production equation (4-53 and 4-36) where the rate of return on Canadian long term bonds was used as a proxy of 'i', nominal rates were used. In the exploration and development (4-51 and 4-52) real rates were used. The industrial price index was used as a deflator in calculating these real rates.

<u>(iv) The Productivity Variable in the Production Phase</u>. The productivity of variable (labour) inputs in the production phase of

the oil and gas industry as represented by the variable μ, is calculated by taking a ratio of the total oil and gas industry output measured in \$ 1971, to total amount spent on wages and salaries, again in \$ 1971 per year. Note that we take labour as a proxy for all variable inputs.

This measure suffers from some inherent bias. First, it not only captures the changes in the productivity of labour, but also incorporates changes which may result due to better utilization of capital. Thus it does not exclusively measure the productivity of labour. Second, increases in wage would lead to an increase in the share of labour without necessarily increasing its productivity. Thus we think that μ as measured here is not the best measure of productivity of labour. Ideally, physical units of both labour and production should be used. However, such data (especially labour force data on man-hours worked in the petroleum industry) are unobservable for much of the 60s. After 1966, the data is available but the grouping includes not only the petroleum sector, but also other mining industries.

<u>(v) The Market Demand Prorationing Variable</u>. The market demand prorationing variable is measured in each year by excess short run capacity, i.e. the ratio between immediately available productive capacity and actual allowable production for that year. The productive capacity is defined and assigned by the AERCB as the maximum sustainable capacity per well. Perhaps a better measure would

have been an inverse of this ratio because as actual market allowable tends to zero, the ratio tends to infinity.

<u>(vi) The Price Variables</u>. The prices of oil (P_{oil}) and gas (P_{gas}) are respectively the netback prices per barrel and per '00 Mcf. (P_{gas} per '00 Mcf is awkward but has been used by the Canadian Petroleum Association.) They are calculated by subtracting the respective average royalties and taxes (municipal and others, excluding income tax) from the wellhead price of oil and of gas. These taxes are taken from the Canadian Petroleum Association, and then allocated between oil and gas on the basis of the relative values of production, to obtain tax per unit of oil and of gas. The yearly average world wellhead price is calculated by taking an average of five sources: (a) Venezuela tia Juana - Light (b) Arab ex Sidon (c) Arab ex Ras Tanura (d) Arab Light and (e) Libya ex Marsa el Breja. The yearly average wellhead price of oil in the U.S.A. is calculated by taking an average of seven different types of oil in U.S.A. The relative price of oil in Alberta relative to the world price ($RP_{oil\ W}$) is calculated by taking the ratio of the Alberta wellhead price to the average world price. Similarly, the price of oil in Alberta relative to the U.S. price ($RP_{oil,\ U.S.}$) is calculated by taking the ratio of the Alberta wellhead price to the average U.S. price. Note that preliminary results indicated that the producers respond more to $RP_{oil\ U.S.}$ than to $RP_{oil\ W}$. Therefore in the final estimating equations, the former was used.

<u>(vii) The Liquidity Variable</u>. Net income for the oil and gas industries after taxes and royalties is taken to be a proxy for the liquidity variable.

<u>(viii) The Corporate Income Tax Rate, Royalty Rates, Write-offs and Allowances</u>. The regulated corporate income tax rate applicable to all industries was used. Royalty rates for both oil and gas were used in our netback price calculations. A weighted average of new oil/gas and old oil/gas royalty rates was used, the weights being the respective production of old oil/gas or new oil/gas. The federal expenditure write-off rates and allowances were obtained from published sources (the reader is referred to Appendix A for more details).

<u>(ix) The Costs</u>. Considerable effort has been devoted in this study to establishing some unobserved micro data - especially those related to costs. The unit costs of exploration and development are calculated as $ per foot drilled in the respective activities, and the unit cost of production for any year as $/BTU of combined oil and gas produced that year. The choice of a deflator for the cost of exploration and development in most cases depends upon how exploration and development are measured. The choice of an appropriate measure of E and D is often quite arbitrary. They are either measured by the number of wells drilled or footage drilled. In the past, studies have used either one. (The reader is referred to the discussion of Section 2 in Chapter IV.) These annual cost estimates covering all of Alberta are provided by the Canadian Petroleum Association, but are not published

for individual fields. For our zone and field data sets, therefore, we used cost data provided directly via questionnaires (given in Appendix C) from the relevant oil company operators in the sampled fields, and from supplementary information held by the Department of Energy and Natural Resources in connection with their Geophysical and Exploratory Drilling Incentives Programme.

In line with the sub-classification adopted by the Canadian Petroleum Association, we sub-divided each of the exploratory, development and operating costs for the fields in each zone into the following sub-categories:

(i). Per foot cost of exploration calculated on the basis of:

(a) per foot cost of exploratory drilling;

(b) per crew cost of seismic activity;

(c) per acre cost of land rentals and lease acquisition.

Each of these cost components is multiplied by the respective activity for each year to yield the total cost for that year. For example, per-crew-cost-of seismic is multiplied by total seismic crews in a particular year and per-acre-cost-of-rentals is multiplied by total acres occupied under the drilling agreements. The total cost is then divided by the total exploratory feet drilled to obtain the per foot cost of exploration. Note that (c) was calculated both gross and net of bonus bids. The former was used for the first model and the latter in the alternative exploration model. This dual approach was followed for the following reasons: first, inasmuch as bonus bids are used to acquire the resource to explore and produce, it is a cost which the operator incurs; second, because the size of the bid depends upon the operator's expectations of profitability , it is also a measure of expected profitability. In the first model, a distinction is not made between costs and expected profitability and hence, we use exploration costs gross of bonus bids. However, in the second model we make a distinction and hence the costs are calculated net of bonus bids.

(ii). Per foot cost of development was calculated on the basis of:

(a) per foot cost of development drilling;

(b) cost of capital employed per foot of development drilling.

The capital expenditures include such expenses as tangible well and lease equipment, pipelines and related facilities, secondary recovery and pressure maintenance projects, natural gas processing plants, office holdings, land, and other machinery and equipment.

(iii). Per BTU cost of operating was calculated on the basis of:

(a) cost of surface equipment per BTU of annual production;

(b) cost of natural gas processing plant per BTU of oil/gas produced;

(c) cost of taxes per unit (excluding income tax) of oil/gas production.

Here we include all taxes expensed and paid to Canadian federal, provincial and municipal governments, including mineral taxes, but excluding income taxes and those taxes that are included as part of the list price of purchases. We calculate each of these categories of cost by generating a cost series, by sub-components, and by fields, for the years 1962 to 1979. A cost series was calculated for each of the four zones, namely Plains, Central, Northern and Foothills, from the data provided by field operators. The exact procedure used to calculate these cost subcomponents is given in Appendix A.

Once these cost series were established it was then possible to experiment with two alternative ways of arriving at a per foot cost of exploration and of development for the various sub-groups in the oil and gas industry. The first is the regression method, and the second is the ratio allocation approach. Although we discuss both these approaches in Appendix A, for our empirical estimation we used the latter method.

2 Estimation Procedures.

As explained in the above section, the data are grouped into four sets. For the first data set, equations (4-51), (4-52), (4-53), and (4-36) are estimated through various econometric methods. First, three stage least squares (3SLS) was used to estimate the four equations. 3SLS is a straightforward extension of the two stage least squares method (2SLS) in which the third stage involves the application of least squares to a set of transformed equations, in which the transformation required is obtained from the reduced form residuals (Koutsoyiannis, 1973).

In the second estimation method, each of the four equations was estimated first with simple OLS and then through Principal Components (PC). The latter was applied due to high multicollinearity among the exogenous variables. The correlation coefficients between the exogenous variables are provided in Table 5-2. From a set of explanatory variables (X's), PC constructs a set of new variables called the principle components which constitute a linear combination of the X's. These new variables are constructed in such a manner that, firstly, the principal components are uncorrelated, and secondly, the first principal component absorbs and accounts for the maximum proportionate variation in the set of all X's, the second principal component absorbs the maximum of the remaining variation in the X's, and so on. Once the principal components are formulated, the dependent variable is regressed on the principal components with the restriction that one or more of the principal components is zero. (Note that if all principal components are taken into account then we simply have OLS estimates). The coefficients so obtained are transformed back into the original coefficients through an inverse linear transformation. The coefficients obtained through this process are sometimes referred to as principal components estimators and like all restricred least squares estimators are known to have smaller variance than the least squares estimator. Also these estimators may be biased unless the restriction imposed on the principal component is true. Since it is often difficult to interpret the various principal components, it is difficult to test whether these restrictions hold true. (For a detailed discussion on the use of this method in solving multicollinearity see Judge, Griffiths, Hill and Lee (1982).

The use of PC in estimating multicollinearity is sometimes questioned. The method is criticized as being a purely statistical device. Recognizing these objections in the current analysis PC is used as an investigative tool rather than the only method of estimation. As compared with OLS, in the present analysis the use of PC reduces the standard error of some coefficients. Also, it changes the coefficients of variables with unanticipated signs. Note that large standard errors and unanticipated signs coupled with high R^2 are the two obvious outcomes of multicollinearity. The R^2 for most OLS equations is substantially high.

Data sets two, three and four are estimated through the OLS, and PC methods of estimation. 3SLS is not used. The estimates from the first data set indicate that there is no statistically significant difference between the estimates from 3SLS and OLS for equations 4-51 (exploration) and 4-52 (development). This may be due to the inherent simultaneity between the two equations which is not explicit in the mathematical formulation. Thus 3SLS does not yield superior estimates than OLS.

For equations 4-53 (QOIL) and 4-36 (QGAS) such is not the case. 3SLS is superior to OLS largely because of the explicit simultaneity between equations (4-53) and (4-36). However, as equation (4-36) is not estimated for data sets two, three and four (these data sets consist of major oil fields where all gas produced is primarily associated), (4-53) for these data sets is estimated only through OLS and PC.

The a priori exploration investment model (equations 4-54, 4-55, and 4-56) for all the four data sets are estimated through OLS and PC methods. The model is also estimated through 3SLS for the first data set. For all estimation, SHAZAM - an econometric computer package from the University of British Columbia - was used.

Apart from collinearity, the other econometric problems encountered in the study relate to the presence of autocorrelation and heteroskedasticity. The Durbin-Watson (D.W.) statistic was used to test for autocorrelation, and wherever it was detected the Cochrane-Orcut iterative procedure was used. However, it should be noted that in SHAZAM, the Cochrane-Orcutt procedure cannot be used with 3SLS and PC. Heteroskedasticity was detected in the grouped data - especially in the second set consisting of observations on cross section and time series. An attempt was made to eliminate such heteroskedasticity, and the results so obtained are reported in the following sections.

3. Empirical Results: Profit Maximization Model.

The following section provides a preview of the results obtained in the study. It outlines the major results from all the four data sets and the estimating equations, 4-51 (p 94), 4-52 (p 94), 4-53 (p 94) and 4-36 (p 85). In subsequent sections, the results for individual equations are discussed[4]. The 3SLS estimates are presented in Table 5-1 (p 133). The OLS and PC estimates are presented in Tables 5-3 (p 145), 5-4 (p 146), 5-8 (p 159) and 5-13 (p 172). For ease of comparison we repeat the 3SLS estimates in these tables.

Recall that in equation (4-51), we anticipate that $a_1 < 0$, $a_2 > 0$, $a_3 > 0$, $a_4 > 0$, $a_5 > 0$ and $a_6 < 0$. In equation (4-52), it is expected that $b_1 < 0$, $b_2 > 0$, $b_3 > 0$, $b_4 > 0$, $b_5 < 0$ and $b_6 > 0$. For equation (4-53), we anticipate that $c_1 < 0$, $c_2 > 0$, $c_3 > 0$, $c_4 > 0$, $c_5 < 0$, $c_6 > 0$ and $c_7 < 0$. Finally, for (4-36), we expect that $d_1 < 0$, $d_2 > 0$, $d_3 > 0$, $d_4 > 0$, $d_5 < 0$, and $d_6 > 0$.

The results now to be discussed indicate that the best estimates were obtained for the first set of data, which pertains to the province as a whole. (The results are contained in Tables 5-1, 5-3, 5-4, 5-8, and 5-13). Most parameters are of expected sign and significant at least at the .95 level of significance. A high R^2 indicates a relatively good fit. The results obtained for the second

TABLE 5-1

PROFIT MAXIMIZATION MODEL
(3SLS Estimates)

4-51. $$\text{Log } E = \underset{(25.21)^{*}}{14.501} - \underset{(-.81535)}{.073148} \text{ Log } C_E + \underset{(2.9470)^{*}}{.51329} [\text{Log } \mu - \text{Log}(a + \mu - i)] - \underset{(.0007149)}{.0000134} (i) + \underset{(2.0596)^{*}}{.65893} \text{ Log } P_{oil}$$

$$+ \underset{(.84693)}{.14127} \text{ Log } P_{gas} + \underset{(4.6326)^{*}}{.80873} \text{ Log } RP_{oil} \text{ U.S.} + \underset{(1.6710)^{**}}{.15544} \text{ Log } C_D$$

$R^2 = .8848$ $\bar{R}^2 = .8424$ D.W. = 2.0209 df = 11

4-52. $$\text{Log } D = \underset{(19.033)^{*}}{17.186} - \underset{(-2.6556)^{*}}{.28491} [\text{Log } C_D - \text{Log } \mu + \text{Log } (a + \mu - i)] - \underset{(-3.0545)^{*}}{.22195} \text{ Log } K_1 + \underset{(1.6645)^{**}}{.63397} \text{ Log } P_{oil}$$

$$+ \underset{(2.6766)^{*}}{.49561} \text{ Log } P_{gas} - \underset{(-3.8474)^{*}}{.51829} \text{ Log MDP} - \underset{(-1.3257)}{.27806} \text{ Log } RP_{oil} \text{ U.S.}$$

$R^2 = .8947$ $\bar{R}^2 = .8615$ D.W. = 1.8700 df = 12

4-53. $$\text{Log } Q_{oil} = \underset{(5.8753)^{*}}{3.9426} - \underset{(-1.4332)^{**}}{.14969} [\text{Log } C_N + \text{Log}(a + \mu - i) - \text{Log}(a - i)] + \underset{(21.000)^{*}}{1.0940} \text{ Log } K_2 + \underset{(.69828)}{.10350} \text{ Log } P_{oil}$$

$$- \underset{(-5.6522)^{*}}{.42442} \text{ Log } P_{gas} - \underset{(-10.893)^{*}}{.50828} \text{ Log MDP}$$

$R^2 = .9872$ $\bar{R}^2 = .9838$ D.W. = 2.0728 df = 13

4-36. $$\text{Log } Q_{gas} = \underset{(-3.6652)^{*}}{-4.7609} - \underset{(-.48331)}{.11818} [\text{Log } C_N + \text{Log}(a + \mu - i) - \text{Log}(a - i)] + \underset{(16.151)^{*}}{1.6565} \text{ Log } K_2 + \underset{(.70943)}{.25299} \text{ Log } P_{oil}$$

$$- \underset{(-1.9206)^{*}}{.34604} \text{ Log } P_{gas}$$

$R^2 = .9541$ $\bar{R}^2 = .9444$ D.W. = 1.2509 df = 14

System R^2 = .9999 Chi-Square = 177.37 d of f = 22

TABLE 5-2

CORRELATION MATRIX

	C_E	$\mu - (a+\mu-1)$	1	P_{oil}	P_{gas}	C_D	$C_D - \mu + (a+\mu-1)$	K_1	MDP	RP_{oil} U.S.	$C_N + (a+\mu-1) - (a-1)$	K_2
C_E	1.0											
$\mu - (a+\mu-1)$	.154	1.0										
1	.657	.618	1.0									
P_{oil}	-.199	-.490	-.552	1.0								
P_{gas}	-.118	-.429	-.488	.931	1.0							
C_D	.239	.560	.151	-.187	-.092	1.0						
$C_D - \mu + (a+\mu-1)$	.179	-.034	-.256	.122	.193	.159	1.0					
K_1	-.133	.342	-.163	.512	.608	-.452	.402	1.0				
MDP	.565	-.073	.557	-.552	-.550	.713	-.205	-.786	1.0			
RP_{oil} U.S.	.127	-.288	-.191	.842	.832	-.127	.131	.540	-.370	1.0		
$C_N + \mu (a+\mu-1) -(a-1)$	.750	.300	.483	-.391	-.235	.825	.337	-.012	.370	-.140	1.0	
K_2	-.090	.240	-.194	.607	.703	-.432	.369	.981	-.755	.681	-.048	1.0

and third data sets, and the fourth (which pertains only to the fifteen selected oil fields) are a little less satisfactory.[5] The signs of some coefficients do not follow the pattern that would be anticipated from economic theory. Further, the R^2 are not as high as that obtained for the first data set. However, some of these results could reflect particular features of the individual fields (and zones) over which the data were grouped.

For Alberta as a whole (first data set), two interesting but unanticipated results are worth mentioning. First, in equation (4-51) (exploration, Table 5-3 and 5-4) we anticipated negative signs for C_D (per foot cost of development drilling) and for C_E. Our results suggest a positive coefficient for C_D. The coefficient of C_E in this equation is negative but insignificant. A possible explanation of these results is that the equation may be capturing a supply effect - i.e., an increase in demand for exploratory inputs will lead to an increase in C_E. Thus the causality may be switched. Instead of measuring the effect of a change in C_E on exploration, we may be observing the effect of a change in E on C_E. This will lead to a positive coefficient of C_E. As C_E and C_D follow similar trends, it will also imply a positive coefficient of C_D. That this may have actually taken place is evident from the following trends. Note that during the period under observation, exploration activity increased dramatically from 737 10^3 metres in 1960 to 2771 10^3 metres in 1979, amounting to an increase of 275%. An increase of such a magnitude may have lead to a substantial increase in cost of exploration. Table 7-1 provides trends in costs of exploratory drilling between 1970 and 1981. Contrary to substantial increases in exploration, except in 1978 and 1979, the development activity increased only marginally from 2142 10^3 metres in 1960 to 2961 10^3 metres in 1977 - an increase of only 38%. (In 1978 and 1979, however, the development activity increased to 3408 10^3 metres and 4138 10^3 metres respectively). Because of marginal increases in D, the inverse causality between D and C_D may not be evident. Hence, in equation (4-52), we still obtain a negative coefficient of C_D.

The second surprising result is that, contrary to our expectations in equation (4-53) (production of oil, Table 5-13 for data covering the province as a whole), the production of oil is positively related to the production of gas. A detailed analysis of this unanticipated result is provided in Section 5. As indicated there, the entire gas production can be divided into two parts - the associated gas production which is in direct proportion to the production of oil because gas is produced as a by-product of oil; and the non-associated gas production which is produced out of purely gas wells. With increases (or decreases) in the production of oil, the production of associated gas would increase (or decrease). Thus part of the total gas production is always positively related to the production of oil. This observation becomes more evident when we look at the results obtained for individual fields (which are all major oil fields) and the results indicate a positive and significant coefficient for the production of gas, i.e. Q_{gas} in equation (4-53) for all fields and zones.

Also, technically and as reflected by the production function, the markets for oil and gas are independent of each other, but they may still be subject to similar external forces, and therefore the trends in both the production of gas and oil may be similar. If such were true, then the non-associated gas production would also be positively related to the production of oil, generating a positive coefficient between the total production of gas and that of oil. The trends in the production of oil and gas are given and discussed further in section 5 of the present chapter.

The wide variation in the size and significance of some of the elasticity parameters (areas of exploration, development and production), and the different signs for the same parameter in the various zones and fields, calls for discussion. Although the inadequacy of sample data could account for some part of these variations and anomalies, particular government programs as well as variations in geological factors could also be responsible.

If we compare and analyze the results obtained from each of the four sets of data for the same equation, we see that the trend in the results obtained from the first set (all provincial) and the fourth set (all 15 fields) is similar. For example, the signs of all the coefficients (except those for cost of operating and level of probable reserves) are the same, although the magnitude of the elasticities vary. However, when the fourth data set is broken into groups to form the second and the third data sets, we obtain opposite signs for some of the same elasticities. For example, consider the explanatory variable C_E in equation (4-51). The elasticity of exploration activity for Alberta with respect to C_E obtained from both the first and fourth data sets though insignificant is negative, and this is what we expect a priori. However, when we analyze the second data set we find that the elasticities of exploration activity with respect to C_E are negative for three zones (Plains, Central, Northern) but positive and significant for one zone (Foothills). Similarly, this elasticity parameter has different signs for different fields. Thus it can be said that although on average, physical exploration activity varies inversely with changes in C_E, this relationship may not always hold true in individual fields. Other factors included in the model (regulatory, institutional etc.) besides pure cost considerations may play an important role, and the effect of these may be stronger in particular fields at certain times.

Besides C_E, two other explanatory variables - market demand prorationing (MDP) and price of oil in Alberta relative to that in the U.S. ($RP_{oil\ U.S.}$) - show different elasticities of exploration and development responsiveness for different fields and zones, and each of these is discussed in the following sections.

The generally similar direction of results obtained from the first and fourth data sets assists in the task of interpretation in several ways: first, the fourth data set is constructed by pooling the observations on individual fields, and subject to the reliability of the sample should represent an average in the province. The first data set relates to aggregate provincial data and it too represents an average in the province. The similar results obtained for both these data sets establish the reliability of the sample of fifteen fields and the related micro data which is obtained primarily from non-published sources. Second, inasmuch as the fourth data set is an average in the province it could be used as a benchmark for comparing the variations between the provincial average and the individual zones and fields. Note that the reliability of the benchmark itself is important.

Our empirical estimates suggest that exploration activity is often more sensitive to product price changes (for both oil and gas prices) than development and production activities. Thus in the exploration phase, where firms are still evaluating the prospects of investing further in the oil and gas industry, it might be argued that the decision to explore or not to explore is quite sensitive to prices and price expectations. But once substantial capital has been invested in exploration, then the concern of the operators may well turn to a recovery of funds through development and eventual production, and these latter activities may be less sensitive to product price changes as such, and more sensitive to immediate market outlets, market allowables and the like. Also, the land tenure system imposes a constraint in terms of the duration over which a lease or a licence is valid. Under the current regulations, the duration of a lease is 5 years i.e., the lessee can only produce before the termination of 5 years.

In the absence of government interference (through, let us say, the drilling incentive program,) we might also expect that the elasticity of exploration, with respect to unit costs of exploration, would be higher than the response elasticities of development and production activities, with respect to changes in their respective unit cost. But government influence is not absent. Since part of the exploration cost is shared by the government through the drilling and geophysical incentives programs (1972 - 1979), we find that development activity is now the most sensitive to changes in cost. There is no significant difference between the cost elasticities of exploration and production. The null hypothesis that $\eta C_E = \eta C_{OP}$ is tested against the alternative hypothesis $\eta C_E \neq \eta C_{OP}$. Since the $F_{calc} < F_{0.01}$, we cannot reject the null hypothesis.

In general, we find that government policies do have an effect on exploration, development and production. Production and development (Tables 5-8 and 5-13) are noticeably affected by MDP, royalties (through prices) and the various tax allowances (through costs). Exploration (Tables 5-3 and 5-4) is affected by royalties (again through prices), various tax allowances (through cost) and apparently by the drilling incentive program of the government.

In the following sections, the elasticity estimates are provided in the various tables. For ease of analysis, the tables also provide the t-statistics and the respective R^2 for each of the equations.

4. The Profit Maximization Model: Exploration.

$$\begin{aligned}\text{Log } E = a_0 &+ a_1 \log C_t + a_2(\log \mu - \log(a + \mu - i)) \\ &+ a_3 i + a_4 \log P_{oil} + a_5 \log P_{gas} \\ &+ a_6 \log C_D + a_7 \log RP_{oil\ U.S.} \qquad (4\text{-}51)\end{aligned}$$

Alberta (data set #1): Equation (4-51) is estimated by using two alternative proxies for i, the rate of discount. (As discussed in section 1 of this chapter, 'i' is first defined as the average rate of return on equity in mining and energy related industries in Canada; second it is defined as the average rate of return on long-term capital employed again in the mining and energy related industries). The estimates of elasticities are given in Table 5-4 . To see whether the discoveries of new fields or pools have an effect on exploration activity, we further modify equation (4-51). We hypothesize that given some level of prices and costs, the discovery of a new field is followed by a surge in exploration activity (due to expectations of finding high level of reserves). This effect is independent over a particular time period of the effect of prices and costs. Thus we introduce in the exploration equation two dummy variables v1 and v2[6], such that, v1 = 1 if a new major[7] field is discovered anywhere in Alberta in that year

= 0 otherwise.

and v2 = 1 if a new major field is discovered in the preceding year

= 0 otherwise.

Figure 5-1 gives the trend in exploratory activity measured by total exploratory feet drilled. The asterisks on this curve indicate the years in which particular major fields were discovered.

Tables 5-3 and 5-4 respectively present the elasticities of physical exploration activity with respect to changes in other variables, with and without the inclusion of the dummy variables in the specification. As a high degree of collinearity was detected among the variables, the model was estimated with both the OLS and PC methods. The signs of both OLS and PC estimates are the same, although PC estimates are more significant and therefore in discussing the results we sometimes discuss the PC estimates only. The results obtained by using the rate of return on capital versus the results obtained by using the rate of return on equity are not significantly different. Thus it is a matter of indifference as to what opportunity rate of return is used. The magnitude of the coefficient for the rate of return on equity is higher than that for rate of return on capital, although the significance of the two coefficients is similar. The introduction of the two dummy variables improves the significance of several variables and increases the R^2, but the difference between the two regressions is not statistically significant. We test this by applying the appropriate F - statistic which is,

$$[(R_Q^2 - R_K^2)/(1-R_Q^2)] * [(N - Q)/(Q - K)]^8$$

and then by comparing it with the tabulated value of F at (Q - K), and (N - Q) degrees of freedom. Here R_Q^2 is the regression estimate with Q variables and R_K^2 the regression estimate with K variables, where Q > K. N is the number of observations. The calculated value is 3.75 which is less than the tabulated value of 4.26 at 5% level of significance. Thus the null hypothesis that there is no significant difference between the two regressions or alternatively, the inclusion of additional explanatory variables does not significantly improve the regression, is not rejected. As v2 has a higher and more significant elasticity coefficient than v1 there seems to be some suggestion of an exploration lag which lasts for more than a year. However, the co-existence of v_1 and v_2 in the estimating equation could also have made v_1 insignificant. Also, the question of timing is important. If a field is discovered at the end of the year, exploration would likely be stimulated in the next year.

Regarding the unit costs of exploratory drilling as an explanatory variable, the results appear somewhat anomalous. The coefficient of

FIGURE 5-1
EXPLORATORY FOOTAGE AND MAJOR FIELD DISCOVERIES

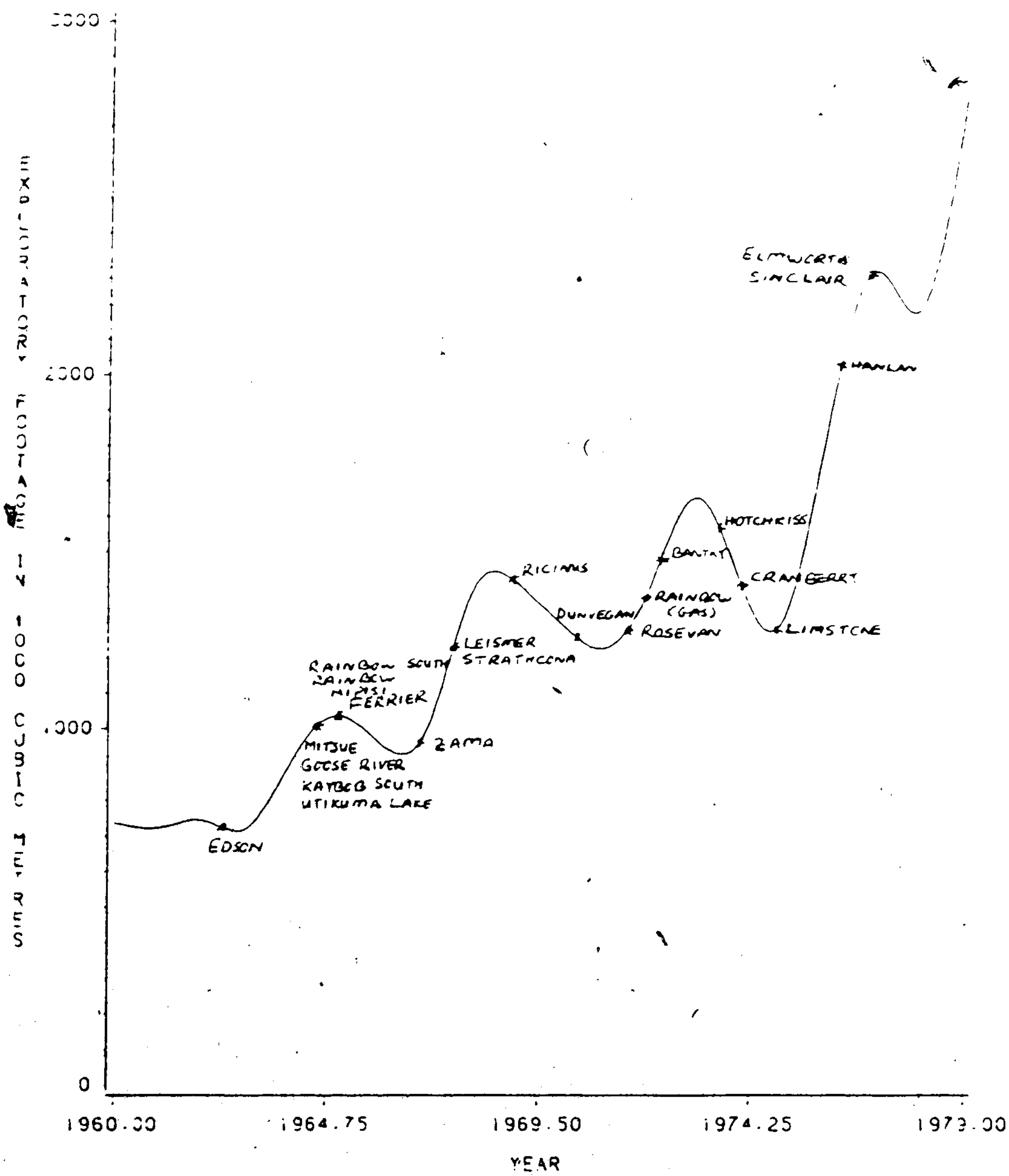


TABLE 5-3

ELASTICITIES OF EXPLORATORY ACTIVITY FOR ALBERTA
(Data Set #1; Dummy Variables Included)

	C_E	P_{oil}	P_{gas}	μ	i	C_D	$RP_{oil\ U.S.}$	V_1	V_2	R^2	$\bar{R}^2$	D.W.	df
OLS - with i defined as rate of return on capital	-.093 (-.55)	.297 (.817)	.369 (1.64)**	.261	.528	.187 (1.45)**	.68 (2.04)*	.145 (2.24)*	.137 (1.98)*	.94	.88	2.48	9
PC - with i defined as rate of return on capital	-.078 (-.854)	.24 (9.27)*	.55 (9.76)*	.092	.229	.29 (4.11)*	.17 (8.03)*	.11 (1.85)*	.17 (2.62)*	.91	.87	1.73	10
OLS - with i defined as rate of return on equity	-.111 (-.778)	.34 (1.03)	.36 (1.66)**	.32	.66	.19 (1.60)**	.14 (2.34)*	.14 (2.35)*	.13 (1.97)*	.94	.88	2.51	9
PC - with i defined as rate of return on equity	-.133 (-1.65)**	.264 (9.54)*	.54 (10.05)*	.034	.017	.29 (3.29)*	.14 (7.19)*	.10 (1.76)*	.14 (2.10)*	.91	.86	1.49	10

NOTE: The t-statistics are enclosed in the parenthesis below the elasticity estimates.

* indicates that the variable is significant at .95 level of significance.

** indicates that the variable is significant at .90 level of significance.

TABLE 5-4

ELASTICITIES OF EXPLORATORY ACTIVITY FOR ALBERTA
(Data Set #1; Dummy Variables Excluded)

	C_E	P_{oil}	P_{gas}	μ	i	C_D	$RP_{oil\ U.S.}$	R^2	$\bar{R}^2$	D.W.	df
OLS - with $\bar{i}$ defined as rate of return on capital	-.160 (-.80)	.534 (1.26)	.174 (.69)	.197	-.535	.205 (1.34)	.786 (2.00)*	.89	.83	2.02	11
PC - with i defined as rate of return on capital	-.097 (-.88)	.206 (7.28)*	.514 (7.88)*	.094	-.074	.260 (3.07)*	.149 (6.46)*	.85	.81	1.41	14
OLS - with $\bar{i}$ defined as rate of return on equity	-.091 (-.50)	.451 (1.08)	.200 (.78)	.205	.292	.180 (1.22)	.695 (1.79)*	.89	.82	2.07	11
PC - with i defined as rate of return on equity	-.084 (-.95)	.206 (8.80)*	.469 (9.14)*	.027	-.132	.220 (2.37)*	.134 (6.24)*	.86	.82	1.47	14
TSLS - with i defined as rate of return on capital	-.073 (-.815)	.659 (2.059)*	.141 (.847)	.353	-.267	.155 (1.671)**	.8097 (4.632)*	.88	.84	2.02	11

NOTE: The t-statistics are enclosed in the parenthesis below the elasticity estimates.

* indicates that the variable is significant at .95 level of significance.

** indicates that the variable is significant at .90 level of significance.

C_E is insignificant in equation (4-51) (except Table 5-3 with PC estimate, where i is defined as the rate of return on equity). To investigate this result further we regressed E on C_E [9], although we realize that the impact of C_E on exploration may be drastically different when other variables such as the price co-exist. For the period 1961-1979, the coefficient is insignificant and negative. But for the period 1974-1979, it is positive and significant. The latter result, could perhaps be due to the impact of demand pressures on costs. These have been discussed above. In all the regression runs using alternative rates of return, with and without the dummy variables, exploration activity is most sensitive to the price of gas. Also, we find that the pattern of exploration elasticities with respect to C_E, P_{oil} and P_{gas} is consistent with the parametric restrictions imposed in Chapter IV [10] i.e. $\eta_{C\,E} < \eta_{P\,oil}$ and $\eta_{C\,E} < \eta_{P\,gas}$, where η is the elasticity.

The elasticity of exploration with respect to μ is positive, indicating that with increases in the productivity of variable inputs (labour) in the production phase, exploration increases. However, as stated in section 1 of this chapter, the way μ is defined, it may also capture the productivity increases due to other factors rather than just labour. Further, when the dummy variables are included, the elasticity of exploration with respect to i is positive, again indicating that with increases in the real rate of return on capital employed, exploration activity would increase. From our discussion in Chapter IV (Section 3), the above two results would occur only if the rate of oil/gas price inflation together with the productivity of labour were greater than the rate of return on capital (or equity) employed. Thus between 1960 and 1979, ($a + \mu$) must have been greater than 1. (Here 'a' is the rate of oil/gas price inflation). In other words, between 1960 and 1979 the price of oil/gas coupled with the productivity of variable inputs must have increased at a rate higher than our measure of the opportunity rate of interest. (During 1960 - 1979, 'a' was 20% per year, 'μ' was 5.18% and 'i' - the real rate of return on capital employed was 2%.)

<u>Zones (data set #2):</u> Table 5-5 (p 149) provides elasticities of exploration for the set of data grouped by zones. For this data set, equation (4-51) is modified to include three regional dummy variables to represent the pooling of data across three fields for each of the zones (two for the Foothills). We do this to eliminate the divergence introduced by pooling the data across 4 fields for each zone (3 in the case of Foothills). Plains, Central and Foothills have a high R^2, indicating a reasonably good fit. Most of the variables are of the anticipated sign and those that appear with an unanticipated sign are not statistically significant. In three out of four zones, exploration activity is the most sensitive (and with the anticipated negative sign) to changes in the unit costs of exploration, C_E. The elasticity of exploration with respect to the unit cost of development, C_D is large and significant, although the signs are reversed for the two newer zones - Northern and Foothills. In this data set, prices, both of oil and gas, appear to have exerted

TABLE 5-5

ELASTICITIES OF EXPLORATORY ACTIVITY FOR ZONES
(Data Set #2; With Regional Dummies)

	C_E	P_{oil}	P_{gas}	μ	i	C_D	$RP_{oil\ U.S.}$	d_1	d_2	d_3	R^2	$\bar{R}^2$	D.W.	df
PLAINS	-6.64	-.10	.328	.261	-2.35	1.61	.186	-.39	3.9	1.[illegible]	.90	.88	1.68	51
	(-10.49)*	(-.71)	(.86)			(2.46)*	(-.98)	(-.64)	(6.59)*	(3.09)*				
CENTRAL	-9.80	-.06	1.05	.838	-3.34	2.47	-1.83	.28	5.4	-1.3	.72	.69	1.32	51
	(-5.29)*	(-.20)	(1.42)**			(1.67)*	(-2.48)*	(.29)	(4.96)*	(-1.46)				
NORTHERN	-.53	.176	.482	-.070	-3.46	-.327	.166	2.26	-.29	1.9	.20	.14	1.57	54
	(-3.18)*	(.54)	(.54)			(-2.00)*	(.53)	(3.2)*	(-.42)	(-2.97)*				
FOOTHILLS	11.43	1.02	.49	.588	6.96	-4.54	-2.34	2.46	1.30		.82	.79	1.99	37
	(8.94)*	(2.34)*	(.35)			(-2.16)*	(-.98)	(2.35)*	(1.11)					

NOTE: The t-statistics are enclosed in the parenthesis below the elasticity estimates

* indicates that the variable is significant at .95 level of significance.

** indicates that the variable is significant at .90 level of significance.

relatively less influence on exploration activity than in the first set covering all wells in the province. P_{oil} is significant only for the Foothills zone. P_{gas} is significant only for the Central zone.

The elasticity of exploration with respect to C_E, as indicated in Section 3, has different signs for different zones. Again the supply effect may have been the cause of a positive coefficient of C_E for certain zones. Note that due to the Exploratory Incentive Program, activity in some zones may have increased much more than in others. The way in which this incentive program is formulated affects various zones of the province differently. The definition of wells qualifying for the exploratory incentive is such that a greater percentage of wells drilled in the Northern and Foothills zones qualify for incentive credits. Note that in order to qualify as an incentive well, a well has to be drilled at least a distance of three miles from any other well. (The definition of an incentive well is different from that of an exploratory well. Exploratory wells consist of five categories - the reader is referred to Appendix A for details.) This requirement is difficult to meet in older zones (eg. Plains and Central) where there already has been extensive drilling[11]. Thus in the newer regions, there will be an incentive to increase exploratory footage. But this may lead to an increase in costs of drilling in these areas and thus may result in a positive coefficient of C_E. Such a possibility is at least suggested by the results obtained for fields in the Northern and Foothills zones.

Another possible cause of the varying signs and significance of C_E could be that firms are not responsive so much to C_E per foot drilled as to cost per unit of reserves of oil and gas found. If the former cost increased with no increase in the latter, then exploration activity might still increase implying a positive sign for the coefficient of C_E. In relatively worked-over and depleted zones, we may find that both the C_E per foot drilled and the C_E per unit of reserves found are increasing, thus exerting a negative influence on exploration. On the other hand, in newer zones (Northern and Foothills) which have not been explored to a similar extent, we may find that although C_E per foot drilled is increasing, C_E per unit of reserves found is not. Note that of the fifteen major oil fields comprising the zone and field data sets, the age since discovery and the state of maturity vary considerably.

Note also that costs are not normalized for depth and this may have caused a problem in areas where per unit costs increase exponentially with depth. In these areas, as footage increases (not necessarily the number of wells), costs will also increase. Hence the direction of causality may change leading to a positive relation between footage drilled and per unit costs. Evidence suggests that in foothills area, costs increase exponentially with footage.

From the results obtained nothing can be said with certainty about the effect of $RP_{oil\ U.S.}$ on individual zones. For three zones (Plains, Northern and Foothills), the variable appears with an insignificant coefficient. For Central it is significant but of unexpected (negative) sign.

As discussed earlier, the investment decision of a prospective oil and gas firm in a particular region is based on not only the return in the oil and gas industry but also on the relative return in other industries, and the relative return in similar industries in other regions. $RP_{oil\ U.S.}$ was taken to be a measure of the return in the Alberta oil and gas industry relative to the return in the oil and gas industry in the U.S.

The results in this section indicate that although $RP_{oil\ U.S.}$ is an important determinant of investment in the province as a whole, it is relatively unimportant in a firm's decision to invest in a particular zone or field rather than another zone or field. In allocating investment funds within the province, the investor chooses between various zones. Thus the decision to invest in a specific zone A depends on the return to other zones, let us say B,C and D. Return may be defined in terms of costs, price of the crudes which vary according to its quality, and the geological success. Similarly, in allocating funds within a zone, the investor chooses between various fields in that zone. Thus investment in field A will depend not only upon the return in field A, but also on the return relative to field B, C and D, all in the same zone. Although $RP_{oil\ U.S.}$ is a determinant of choice of investing in either Alberta or the U.S., it does not determine the choice of investing between zone A or zone B or alternatively between field A or field B.

Thus we realize that equation (4-51) in its present form may be more appropriate for the aggregate analysis i.e., for the aggregate oil and gas industry in Alberta. For individual fields and zones, it should be modified to incorporate the interfield or interzonal choice available to the investor. But to maintain uniformity in the analysis, we do not modify 4-51.

Fields (data set #3): Table 5-6 (p 154) gives the exploration elasticity estimates for each of the 15 fields. The estimates for most variables vary significantly. The elasticity with respect to C_E ranges from -15.23 for Judy Creek to 13.51 for Turner Valley. The elasticity with respect to P_{oil} ranges from -.160 for Leduc to 3.78 for Virginia hills; and the elasticity with respect to P_{gas} ranges from -3.25 for Judy Creek to 2.58 for Ferrier. The explanation for a positive sign for C_E for fields in the Northern and Foothills zones is the same as that advanced above. The C_E has a negative and significant coefficient for fields in the Plains and Central zones. Note that most fields in these zones are older, well established fields with small chances of finding new deposits of oil and gas. Thus, increases in C_E may lead to significant decreases in exploratory activity in these areas, but this activity may be transferred elsewhere to take fuller advantage of the exploratory drilling subsidy program. No specific pattern can be established for the effect of $RP_{oil\ U.S.}$ on individual fields. It is significant for some fields

TABLE 5-6

ELASTICITIES OF EXPLORATORY ACTIVITY FOR FIELDS
(Data Set #3)

	C_E	P_{oil}	P_{gas}	μ	i	C_D	RP_{oil} U.S.	R^2	$\bar{R}^2$	DW	df
BONNIE GLEN	-6.82 (-8.12)*	.29 (1.42)**	.88 (1.59)**	.151	.446	-1.78 (-9.03)*	-.035 (-.160)	.92	.90	1.75	10
FERRIER	.879 (2.05)*	.94 (2.13)*	2.58 (2.11)*	-.507	-3.45	.27 (2.16)*	.92 (2.09)*	.32	.20	2.32	11
JUDY CREEK	-15.23 (-4.92)*	2.41 (1.38)**	-3.25 (-.92)	.0748	-1.49	-.54 (-.17)	4.49 (.68)	.80	.68	2.97	9
LEDUC	-5.52 (-2.17)*	-.160 (-.31)	.52 (.42)	.536	-3.10	3.80 (1.43)**	-1.05 (-1.25)	.41	.15	1.38	9
PEMBINA	.77 (1.79)*	.42 (2.25)*	1.26 (3.25)*	-.298	.231	.68 (1.00)	.74 (2.85)*	.68	.59	2.39	10
RAINBOW	.74 (.92)	-.077 (-.29)	.11 (.22)	-.085	-5.37	-.65 (-.79)	.12 (.66)	.58	.45	2.13	10
RED EARTH	-.286 (-1.03)	.92 (1.42)**	2.38 (1.68)**	.427	-11.06	-.43 (-.15)	.83 (1.67)**	.35	.15	2.88	9
RED WATER	-5. 1 (-4.43)*	.44 (.59)	.21 (.129)	.624	-.629	3.40 (2.45)*	1.16 (.31)	.80	.67	2.38	8
RICINUS	10.8 (5.65)*	1.5 (1.12)	-1.37 (-.59)	1.432	6.76	-4.96 (-1.10)	2.87 (.64)	.85	.76	2.35	9

TABLE 5-6: (CONTINUED)

	C_E	P_{oil}	P_{gas}	μ	i	C_D	$RP_{oil\ U.S.}$	R^2	$\bar{R}^2$	D.W.	df
SWAN LAKE[(a)]	-	-	-	-	-	-	-	-	-	-	-
TURNER VALLEY	13.51 (3.05)*	2.23 (2.79)*	-2.91 (-1.12)	-.0918	12.79	-11.57 (-3.24)*	3.46 (.69)	.70	.59	1.61	9
UTIKUMA LAKE	-.23 (-.33)	.58 (.56)	.93 (.45)	-.084	10.34	-1.78 (-.31)	.032 (.03)	.35	.16	1.72	10
VIRGINIA HILLS	-13.73 (-2.55)*	3.78 (1.28)	-2.32 (-.93)	3.75	1.89	12.06 (3.72)*	-1.86 (-.40)	.81	.70	1.98	9
WIZARD LAKE	-4.40 (-8.46)*	.18 (1.05)	.35 (.89)	-.549	1.50	-3.22 (-8.34)*	.33 (2.20)*	.88	.85	2.30	10
ZAMA	-2.15 (-.37)	.065 (.038)	.74 (.20)	1.86	-8.58	4.41 (.84)	-5.19 (-.71)	.49	.18	1.91	9

NOTE: The t-statistics are enclosed in the parenthesis below the elasticity estimates.

* indicates that the variable is significant at .95 level of significance.

** indicates that the variable is significant at .90 level of significance.

(a) due to a lack of sufficient observations the results could not be obtained for this field.

(Ferrier, Pembina, Red Earth and Wizard Lake) and insignificant for others. The results confirm our above discussion.

<u>Alberta - Pooled Fields - Sample Data (data set #4):</u> Table 5-7 (p 157) gives the results obtained from the fourth data set, in which the field data is pooled over all zones. Note that because we have grouped the data over 15 groups (fields), we introduce 14 cross - section dummies[12]. The coefficients of these dummy variables measure the difference between the intercept of the first group and that of the other groups. Specifically, the intercept of the first field would be the intercept of the equation; the intercept for the second field would be the intercept of the equation plus the coefficient of the first dummy; the intercept of the third field would be the intercept of the equation plus the coefficient of the second dummy; and so on. For ease of exposition, we do not quote the coefficients of these regional dummies. The R^2 is not as high as that obtained from the first data set. C_E has a negative coefficient which is significant at the 5% level of significance. The magnitude of elasticity with respect to P_{gas} is smaller than the elasticity with respect to P_{oil}, although the former elasticity is not significant. The variables μ, i, C_D and $RP_{oil\ U.S.}$ have the same signs on their respective elasticities as those obtained from the first data set, although the significance levels are uniformly lower.

TABLE 5-7

ELASTICITIES OF EXPLORATORY ACTIVITY FOR ALBERTA POOLED DATA
(Data Set #4)

	C_E	P_{oil}	P_{gas}	μ	i	C_D	$RP_{oil\ U.S.}$	R^2	R^2	D.W.	df
OLS	-1.69	1.79	.234	1.49	1.30	.750	.11	.54	.49	1.70	203
	(-1.79)*	(.44)	(.13)			(.818)	(.058)				
PC	-2.40	.529	.796	2.17	2.02	.035	1.38	.52	.47	1.62	205
	(-2.58)*	(1.77)*	(.95)			(.039)	(.67)				

NOTE: The t-statistics are enclosed in the parenthesis below the elasticity estimates.

* indicates that the variable is signficant at .95 level of significance.

** indicates that the variable is significant at .90 level of significance.

5. The Profit Maximization Model: Development.

$$\text{Log } D = b_0 + b_1(\log C_D - \log \mu + \log(a + \mu - i)) + b_2 \log K_1 + b_3 \log P_{oil} + b_4 \log P_{gas} + b_5 \log MDP + b_6 \log RP_{oil\ U.S.} \qquad (4\text{-}52)$$

Alberta (data set #1). The results obtained by estimating equation (4-52) for data covering Alberta as a whole are given in Table 5-8 (p 159). As for exploration, we estimated equation (4-52) with two alternative rates of return: There is no significant difference between the results obtained by taking either the rate of return on all capital employed in the industry as a discounting variable or the rate of return on equity in the industry. The variables, except K_1, (probable reserves), are of anticipated sign although some are insignificant. As predicted by the theoretical analysis in Chapter IV (Section 5), the elasticity with respect to C_D is greater than the elasticity with respect to P_{oil} and with respect to P_{gas}.[13] (Note that the elasticity of development with respect to per unit cost of development is $[1/(\delta-1)]$ and with respect to the price of oil and the price of gas respectively is $[\phi/(\delta-1)]$ and $[\psi/(\delta-1)]$. However, the difference between these elasticities is not significant. We test the null hypothesis $\eta C_D = \eta P_{oil}$ against the alternative hypothesis $\eta C_D = \eta P_{oil}$ using an F ratio at $v_1 = 1$ and $v_2 = (n-k)$ degrees of freedom. As the $F_{cal} < F_{0.01}$, we cannot reject the null hypothesis. (As ϕ and ψ are greater than zero but less than one, $[1/(\delta-1)] > [\phi/(\delta-1)]$ and

TABLE 5-8

ELASTICITIES OF DEVELOPMENT ACTIVITY FOR ALBERTA
(Data Set #1)

	C_D	K_1	P_{oil}	P_{gas}	μ	i	$RP_{oil\ U.S.}$	MDP	R^2	$\bar{R}^2$	D.W.	df
OLS - with i as rate of return on capital	-.241 (-1.85)*	-.49 (-3.40)*	.246 (.50)	.480 (2.23)*	.459	.149	.288 (.65)	-.95 (-3.86)*	.90	.86	1.50	12
PC - with i as rate of return on capital	-.423 (-2.43)*	-.036 (-.39)	.279 (5.90)*	.523 (5.48)*	.807	.262	.173 (5.58)*	-.08 (-1.29)	.76	.72	.92	15
OLS - with i as rate of return on equity	-.184 (-1.59)**	-.56 (-3.97)*	.24 (.48)	.478 (2.15)*	.319	.097	.324 (.71)	-.99 (-3.96)*	.90	.85	1.41	12
PC - with i as rate of return on equity	-.240 -(1.38)	-.084 (-.81)	.27 (5.19)*	.545 (5.20)*	.429	.127	.183 (5.30)*	.007 (.15)	.71	.65	.73	15
TSLS - with i defined as rate of return on capital	-.2859 (-2.655)*	-.222 (-3.05)*	.634 (1.664)**	.496 (2.676)*	.148	-.0425	-.278 (-1.325)	-.518 (-3.85)*	.89	.86	1.87	12

NOTE: The t-statistics are enclosed in the parenthesis below the elasticity estimates

* indicates that the variable is significant at .95 level of significance

** indicates that the variable is significant at .90 level of significance

$[1/(\delta - 1)] < [\psi/(\delta - 1)]$. The elasticity with respect to C_D in absolute value is less than the elasticity with respect to P_{gas}. Again, by using the F ratio, we test for the significance of difference between the elasticities with respect to C_D and P_{gas}. The null hypothesis $\eta C_D = \eta P_{gas}$ is tested against the alternative hypothesis $\eta C_D = \eta P_{gas}$. Since $F_{cal} > F_{0.01}$, we reject the null hypothesis and accept that the elasticity with respect to C_D is significantly less than the elasticity with respect to P_{gas}. Looking at the PC estimates we observe that development is most sensitive to changes in the price of gas and a little less to changes in C_D and P_{oil}.

The unexpected (negative) sign for the level of probable reserves, K_1 is rather curious. Several experimental estimations were made to determine the exact cause of this seemingly anomalous sign. If D is regressed only on K_1, then K_1 shows a positive and significant (.90 level) coefficient.[14] We therefore assume that K_1 appears in such a relation with other independent variables that even the application of PC does not solve the problem of collinearity. Analyzing the correlation table of exogenous variables, it was found that K_1 is highly correlated (.74) with MDP. We therefore estimated the equation (4-52) omitting MDP. However, the coefficient of K_1, although insignificant, is still negative.[15]

As an alternative we specified a general form[16] of equation (4-52) and estimated it with and without MDP. The difference between the general form and that of equation (4-52) is that in the former the term (log C_D - log μ + log(a+ μ -i)) is disaggregated into its three components, log C_D, log and log(a + μ -i) i.e. the restriction on b_1 is dropped. Thus the coefficients of these three variables will no longer be equal.The results are as given below:

$$
\begin{aligned}
\text{(a) } \log D_t = {} & \underset{(19.35)}{16.14} - \underset{(-6.72)}{.572} \log C_D + \underset{(1.89)}{.053} \log \mu + \underset{(5.35)}{.230} \log(a + \mu - i) \\
& - \underset{(-.203)}{.0082} \log K_1 + \underset{(7.50)}{.152} \log P_{oil} + \underset{(9.24)}{.165} \log P_{gas} \\
& + \underset{(2.65)}{.088} \log RP_{oil\ U.S.} - \underset{(-5.38)}{.394} \log MDP
\end{aligned}
$$

$R^2 = .88$ $\bar{R}^2 = .86$ D.W. = 1.71 df = 15

$$
\begin{aligned}
\text{(b) } \log D_t = {} & \underset{(8.84)}{13.23} - \underset{(4.14)}{.64} \log C_D + \underset{(2.33)}{.16} \log \mu + \underset{(3.37)}{.247} \log(a + \mu - i) \\
& + \underset{(1.75)}{.145} \log K_1 + \underset{(4.89)}{.147} \log P_{oil} + \underset{(6.38)}{.148} \log P_{gas} \\
& - \underset{(-2.38)}{.1060} \log RP_{oil\ U.S.}
\end{aligned}
$$

$R^2 = .81$ $\bar{R}^2 = .77$ D.W. = 1.33 df = 15

In the above equations, when MDP is excluded, K_1 has a positive and significant (.95) coefficient. Also the goodness of fit (.81 as compared to .76 in Table 5-8) and the significance of the variables improves under these general formulations.[17] Thus from the above econometric evidence, we conclude that the unanticipated sign of K_1 may be due to certain econometric problems (viz. high collinearity among the explanatory variables).

As in the case for exploration, the elasticities of development with respect to μ and i are positive. However, the significance of these two variables cannot be estimated. Again, the discussion in Chapter IV (Section 3) indicates that the rate of inflation in the oil and gas industry combined with the productivity change in this industry has been greater than the opportunity rate of return on capital employed over the period sampled. This was also the conclusion reached by the results obtained from equation 4-51. Thus even with increases in the cost of capital, firms would invest in the oil and gas industry, in anticipation of higher profits due to a higher rate of output price inflation, and productivity changes.

As discussed in Chapter IV, the elasticity with respect to MDP can either be negative or positive. For the province, we get a negative elasticity with respect to MDP, implying that restricted markets constrain the development activity. For individual zones and fields, however, we obtain varying signs.

Zones (data set #2): Table 5-9 (p 163) gives the results of equation (4-52) for the four zones. The coefficient of C_D is of the expected negative sign for Plains, Central and Northern but of reverse sign for Foothills. $RP_{oil\ U.S.}$ has a positive and significant coefficient for only Plains and Central. As observed for the first data set, the elasticities with respect to μ and i are positive. MDP has a negative coefficient for Plains and Central, and a positive sign for the other two. This is in line with what we hypothesised earlier. The MDP is likely to have two opposing

TABLE 5-9

ELASTICITIES OF DEVELOPMENT ACTIVITY FOR ZONES
(Data Set #2)

	C_D	K_1	P_{oil}	P_{gas}	μ	i	RP_{oil} U.S.	MDP	d_1	d_2	d_3	R^2	$\bar{R}^2$	D.W.	df
PLAINS	-2.21	.163	.88	1.08	4.21	[illegible]37	.96	-4.12	4.27	2.76	2.78	.30	.22	2.08	52
	(-1.46)**	(1.03)	(2.13)*	(1.30)**			(2.51)*	-(2.81)*	(2.87)*	(2.01)*	(1.69)*				
CENTRAL	-1.24	.232	.77	1.60	2.36	.769	.59	-.19	-.54	.52	2.79	.34	.28	.84	53
	(-.95)	(2.13)*	(2.33)*	(2.36)*			(2.40)*	(-1.61)**	(-.67)	(.73)	(3.0)*				
NORTHERN	-1.30	.107	.041	-.092	2.48	.807	.163	1.83	4.16	4.01	4.10	.35	28	1.81	52
	(-.90)	(1.24)	(.11)	(-.14)			(.46)	(2.73)*	(4.05)*	(4.08)*	(3.59)*				
FOOTHILLS	.99	.52	.67	1.69	1.88	.614	.65	[illegible]156	1.85	[illegible]		.73	.69	1.16	38
	(.43)	(5.39)*	(1.27)	(1.90)*			(.85)	(.423)	(1.24)	(.79)					

<u>NOTE</u>: The t-statistics are enclosed in the parenthesis below the elasticity estimates.

* indicates that the variable is significant at .95 level of significance.

** indicates that the variable is significant at .90 level of significance.

TABLE 5-10

ELASTICITIES OF DEVELOPMENT ACTIVITY FOR ZONES
(Data Set #2; Heteroskedastic Estimates)

	C_D	K_1	P_{oil}	P_{gas}	μ	i	RP_{oil} U.S.	d_1	d_2	d_3	R^2	$\bar{R}^2$	D.W.	df
PLAINS	-29.42	.95	3.50	3.63	56.13	18.26	3.50	7.82	-22.7	-31.21	.93	.93	2.16	53
	(-1.79)*	(27.70)*	(.91)	(.44)			(1.12)	(1.03)	(-2.35)*	(-2.45)*				
CENTRAL	-174.02	1.02	41.04	40.4	331.99	108.04	28.71	-110.9	200.0	41.46	.50	.49	2.01	53
	(-1.68)*	(6.16)*	(1.46)**	(.85)			(1.34)**	(-1.54)**	(-2.09)*	(.608)				
NORTHERN	-.82	.84	1.09	2.63	1.564	.509	.24	1.49	5.24	-6.27	.58	.55	2.23	55
	(-.27)	(8.54)*	(.34)	(.34)			(.46)	(.51)	(.48)	(-.47)				
FOOTHILLS	-78.43	.679	42.91	34.46	149.63	48.69	351.53	-85.51	-49.27		.79	.75	1.05	37
	(-.65)	(7.52)*	(2.90)*	(1.06)			(2.51)*	(-1.44)**	(-.72)					

NOTE: The t-statistics are enclosed in the parenthesis below the elasticity estimates.

* indicates that the variable is significant at .95 level of significance.

** indicates that the variable is significant at .90 level of significance.

effects on development: first, by restricting the amount of oil or allowable market assigned to every producible well it proves to be a disincentive to added development activity; second, inasmuch as the program assures a share of the market to all producers, it leads to increased drilling. Note that the 1950 program clearly encouraged excessive drilling as prorationing was based on allocation per well. Since 1964, the allocation was made on per pool basis, and therefore encouraged the discovery of pools[18]. Since after discovery, major oil pools require extensive development drilling, the changes introduced in 1964 may have indirectly contributed to an increase in development activity[19].

In newer areas, where new pools were discovered the positive effect of MDP both before and after 1964 may have outweighed the negative impact of MDP. Also note that MDP will have a negative impact on producers such as the major integrated companies with significant market outlets. The effect on independents with no market outlets will be positive. The share in drilling activity of independents increased dramatically from 33% in 1950 to 76% in 1970[20]. Unfortunately, the analyses in this thesis does not distinguish between the two producers.

Because we have pooled the data (from different fields), we tested for the presence of heteroskedasticity. Following that, we transform the data by dividing all variables by MDP[21] and then applying the PC to the transformed variables. The results are shown in Table 5-10 (p 164). Note that the R^2 increases substantially and the significance of some coefficients changes. This indicates that the low R^2 indicated by our PC and OLS estimates is due to the presence of heteroskedasticity. However, as indicated by Maddala (1977, p. 266), the intent of this deflating procedure is to get more efficient estimates, but once these estimates are obtained, they cannot be used for any further inferences. For any inference the untransformed or the original equation should be used. Hence for our sensitivity and forecasting analysis in the next Chapter we use the coefficients given in Table 5-9.

<u>Fields (data set #3)</u>: The elasticity estimates of development activity for individual fields are given in Table 5-11 (p 167). In most cases the price of oil has a high elasticity coefficient. Also, the price of gas has a significant coefficient although it is negative in some cases. As the fields in question are basically oil fields such a result is not unexpected.[22] K_1 (level of probable reserves) does not show any consistent pattern. It appears with the anticipated positive sign for some fields and with an unanticipated negative sign for others. The coefficients of C_D and $RP_{oil\ U.S.}$ appear with the anticipated sign in most cases, although they are not significant in some. MDP has a positive effect on the newer fields. μ and i in most cases have positive elasticities, again implying that between 1960 and 1979 $(a + \mu) > i$. Thus even if 'i' had increased over the period, this result suggests that firms continued to invest in the industry in anticipation of even higher

TABLE 5-11

ELASTICITIES OF DEVELOPMENT ACTIVITY FOR FIELDS
(Data Set #3)

	C_D	K_1	P_{oil}	P_{gas}	μ	i	$RP_{oil\ U.S.}$	MDP	R^2	$\bar{R}^2$	D.W.	df
BONNIE GLEN	-3.0 (-.8)	-	.051 (.00)	-.113 (-.06)	5.72	1.86	.196 (.20)	.077 (.06)	.030	-.145	1.91	11
FERRIES	-4.18 -(1.26)	.67 (6.52)*	1.01 (2.29)*	.60 (.70)	7.97	2.56	6.66 (2.29)*	1.83 (.90)	.88	.84	3.19	9
JUDY CREEK	5.09 (1.24)	.21 (1.03)	37.66 (1.91)*	-8.10 (-1.09)	-9.71	-3.16	-14.40 (-1.20)	-7.71 (-.90)	.51	.09	1.48	7
LEDUC	-1.48 (-.49)	.020 (.056)	1.33 (1.79)*	2.42 (1.74)*	2.82	.918	-.88 -(1.88)*	-1.64 (-.93)	.26	.045	3.06	10
PEMBINA	-.62 (-1.30)	.25 (1.81)*	.037 (.36)	-.026 (-.14)	1.18	.385	.082 (.84)	.24 (1.35)	.26	.03	2.49	10
RAINBOW	1.10 (1.30)	.47 (2.74)*	.603 (1.56)**	-.210 (-2.48)*	-2.098	.683	5.21 (2.43)*	-1.51 (-1.24)	.67	.47	1.47	8
RED EARTH	-.85 (-1.93)*	-.015 (-.44)	.16 (.56)	-.90 (-1.34)	1.62	.528	1.71 (1.21)	1.09 (1.42)**	.32	.12	1.99	10
RED WATER	-.95 (-.34)	.261 (1.17)	.87 (1.57)**	1.98 (1.51)**	1.81	.589	.72 (1.57)**	.036 (.091)	.32	.12	1.99	10
RICINUS	-1.99 (-.46)	.60 (4.36)*	1.03 (.85)	1.59 (1.06)	3.79	1.23	.46 (1.10)	-1.02 (-.62)	.69	.60	1.60	10

TABLE 5-11: (CONTINUED)

	C_D	K_1	P_{oil}	P_{gas}	μ	i	$RP_{oil\ U.S.}$	MDP	R^2	$\bar{R}^2$	D.W.	df
SWAN LAKE	-.739 (-.73)	- -	.28 (.66)	-.83 (-.85)	1.41	.458	1.77 (.83)	-.35 (-.91)	.20	-.02	1.67	10
TURNER VALLEY	-.54 (-.10)	-.01 (-.039)	2.21 (.48)	4.27 (2.0)*	1.03	.335	.129 (.054)	-3.6 (-.53)	.52	.31	1.29	9
UTIKUME LAKE	-4.13 (-1.06)	-.030 (-.13)	.44 (.41)	.27 (.077)	7.88	2.56	13.44 (1.68)**	9.07 (1.13)	.46	.13	2.76	8
VIRGINIA HILLS	1.34 (.319)	- -	1.68 (2.0)*	3.71 (2.07)*	-2.55	-.832	1.07 (1.84)*	-.083 (-.151)	.28	.15	.99	10
WIZARD LAKE	-2.71 (-.807)	-	.050 (.21)	-1.04 (-.43)	5.17	1.68	.173 (.132)	-3.1 (-.50)	.29	.07	1.99	10
ZAMA	12.52 (1.72)**	-.26 (-1.04)	-15.33 (-2.85)*	.824 (.133)	-23.88	-7.77	-9.90 (-.84)	-22.3 (-2.62)*	.58	.32	2.01	8

NOTE: The t-statistics are given in parenthesis below the elasticity estimates.

* indicates that the variable is significant at .95 level of significance.

** indicates that the variable is significant at .90 level of significance.

profits in the future. However, as μ and i have derived coefficients, the significance of these estimates cannot be established.

Alberta - Pooled Sample Data (data set #4): Although the R^2 obtained for equation (4-52) from the fourth set of pooled sample data (Table 5-12, p 170) is not as high as that obtained from the first data set, all variables including K_1 are of the anticipated signs and are significant (except μ and i for which the significance cannot be established). MDP has the highest elasticity parameter and as in the first data set is negative and significant. P_{gas} has a higher elasticity than P_{oil}. However, we test for the significance of the difference by using the t-test for equality of coefficients at n-k degrees of freedom. We test the hypothesis that $\eta P_{oil} = \eta P_{gas}$, which is not rejected because the difference between ηP_{oil} and ηP_{gas} is found to be insignificant at 203 degrees of freedom. The elasticity of almost all variables is higher for this set of data than for the first set.

A consistently positive and significant elasticity of development activity with respect to K_1 using the second and fourth data sets indicates again that a negative sign obtained from the first data set may be due to particular econometric problems. Note that for the third data set, K_1 has a negative coefficient for four fields, although these coefficients are statistically insignificant.

TABLE 5-12

ELASTICITIES OF DEVELOPMENT ACTIVITY FOR ALBERTA POOLED DATA
(Data Set #4)

	C_D	K_T	P_{oil}	P_{gas}	μ	i	$RP_{oil\ U.S.}$	MOP	R^2	$\bar{R}^2$	D.W.	df
OLS	-1.23	.30	.83	2.56	2.35	.763	-3.92	-3.83	.49	.44	1.57	203
	(-1.46)**	(5.62)*	(.178)	(1.39)**			(-1.51)**	(-2.70)*				
PC	-.76	.35	.70	.76	1.45	.472	.51	-3.32	.42	.38	1.42	207
	(-1.09)	(6.25)*	(2.87)*	(2.04)*			(2.94)*	(-3.61)*				

NOTE: The t-statistics are enclosed in the parenthesis below the elasticity estimates.
* indicates that the variable is signficant at .95 level of significance.
** indicates that the variable is significant at .90 level of significance.

6. The Profit Maximization Model: Production.

$$\begin{aligned}\text{Log } Q_{oil} = c_0 &+ c_1(\log C_N + \log(a + \mu - i) - \log(a - i)) \\ &+ c_2\log K_2 + c_3\log P_{oil} + c_4\log P_{gas} \\ &+ c_5\log Q_{gas} + c_6(\log Q_{oil} - \log Q_{gas})^2 \\ &+ c_7\log MDP \qquad (5\text{-}53)\end{aligned}$$

$$\begin{aligned}\text{Log } Q_{gas} = d_0 &+ d_1\log C_N + \log(a + \mu - i) - \log(a - i)) \\ &+ d_2\log K_2 + d_3\log P_{oil} + d_4\log P_{gas} \\ &+ d_5\log Q_{oil} + d_6(\log Q_{oil} - \log Q_{gas})^2 \qquad (5\text{-}36)\end{aligned}$$

Alberta (data set #1): The production equation performs very well for all the data sets. Due to explicit simultaneity between Q_{oil} and Q_{gas}, we estimate these two equations only within the 3SLS framework. Table 5-13 provides the 3SLS estimates. Note that we have three sets of estimates. The first is obtained by estimating 4-53 and 4-36 with 3SLS. The second set is obtained by estimating 4-51, 4-52, 4-53 and 4-36 again with 3SLS. Because of high correlation between Q_{oil} or Q_{gas} and $(Q_{oil} - Q_{gas})^2$, the results are biased. We thus derive the reduced form equations of Q_{oil} and Q_{gas} and estimated the model with four equations. The third set provides these estimates. Note that (4-53) and (4-36) no longer have Q_{gas} or Q_{oil} and $(Q_{oil} - Q_{gas})^2$ as exogenous variables. Thus,

TABLE 5-13

ELASTICITIES OF OIL AND GAS PRODUCTION FOR ALBERTA
(Data set #1; 3SLS Estimates)

	C_N	K_2	P_{oil}	P_{gas}	u	t	Q_{gas}/Q_{oil}	$[Q_{oil}-Q_{gas}]^2$	MDP	R^2	$\bar{R}^2$	D.W.	df
FROM 2 EQUATION MODEL (4-53 and 4-36)													
Q_{oil}	2.1503 (.52135)	30.53 (.5090)	4.7767 (-.5292)	6.00 (.4935)	-.611	2.398	19.338 (.52694)	.79088 (1.3033)	-.60326 (-8.8638)	.9920	.9872	1.9609	11
Q_{gas}	.19963 (.4505)	.7595 (1.589)	.15547 (.4568)	-.0340 (-.207)	-.0567	2.258	.60231 (2.105)	-.26455 (-.109)	--	.9682	.9508	1.2853	11
FROM 4 EQUATION MODEL (4-51, 4-52, 4-53 and 4-36)													
Q_{oil}	1.1962 (.3046)	-16.916 (-.2962)	-2.7721 (.3226)	3.2473 (.20053)	-.340	1.334	11.025 (.31565)	1.1204 (1.9320)	-.58309 (-8.7137)	.9917	.9868	1.9165	11
Q_{gas}	.1887 (.6214)	.8132 (1.8706)	.11169 (.27109)	.04243 (-.1792)	-.0536	.210	.57957 (2.1330)	.0660 (.04691)	-	.9680	.9505	1.2331	11
FROM 4 EQUATION MODEL (4-51, 4-52, 4-53 and 4-36) WITH REDUCED FORM EQUATIONS													
Q_{oil}	-.150 (-1.43)	1.09 (21.0)	.103 (.698)	-.424 (-5.65)	.042	-.157	-	-	-.508 (-10.89)	.987	.980	2.07	13
Q_{gas}	-.118 (-.483)	1.66 (16.15)	.253 (.789)	-.346 (-1.92)	.034	-.132	-	-	-	.95	.94	1.25	14

$$Q_{oil} = c_0 + c_1(\log C_N + \log(a + \mu - i) - \log(a - i)) + c_2 \log K_2 + c_3 \log P_{oil} + c_4 \log P_{gas} + c_7 \log MDP$$

and

$$Q_{gas} = d_0 + d_1(\log C_N + \log(a + \mu - i) - \log(a - i)) + c_2 \log K_2 + c_3 \log P_{oil} + c_4 \log P_{gas}$$

In all the empirical estimates of equations (4-53) and (4-36), most variables are not significant, although the R^2 is very high. Market Demand Prorationing is significant in all equations. The results indicate that in the production phase, the operators are less sensitive to changes in prices and costs, but their decision to produce is controlled largely by the market.

The first two sets of results in Table 5-13 indicate that Q_{oil} and Q_{gas} are positively related in both the equations (4-53) and (4-36). Our model however predicts a negative relationship. A negative coefficient of Q_{gas} and a positive coefficient of $(Q_{oil} - Q_{gas})^2$ imply that $0 \leq \beta \leq 1$ and $d \geq 1$ which are the conditions imposed on the parameters in our model (see Chapter IV, Section 3). Note that the condition $d \geq 1$ is required for the concavity of the transformation function. The concavity implies increasing opportunity cost of transformation of production of oil to production of gas or vice versa. Because of the problem of over-identification, we obtain 2 values of d. From the 2 equation model (see Table 5-13) d= .7499 (equation 4-53) or d = -.1052 (equation 4-36). From the 4 equation model, we obtain d = 1.018 (equation 4-53) and d = -.027 (equation 4-36).

Interpretation of results given such varying values of d is quite difficult. We try to deal with this problem by deriving the reduced form of equations (4-53) and (4-36) and then re-estimating the model. Results are provided in Tables 5-1 and 5-13.

Despite the re-estimation of the model with reduced form equations, let us pursue why we may have obtained positive coefficients of c_5 (coefficient of Q_{gas} in equation 4-53) and d_5 (coefficient of Q_{oil} in equation 4-36). Note that the total production of gas broken into two components: 'non-associated' gas which is free of oil, and 'associated' gas which is a by-product of oil. Operators have little control over the latter quantity of gas produced, i.e. if X cubic metres of oil is produced then Y cubic metres of gas is also produced. On the other hand, the non-associated gas can be produced independently of oil from purely gas pools and wells. These pools have a minor amount of oil in them, and whatever oil there is, it is produced as a by - product of gas.

The production of associated gas generally varies positively with the production of oil - i.e. with increases in the production of oil it increases, and with decreases in the production of oil, it diminishes. The production of non-associated gas on the other hand, is quite independent of the production of oil. However, though the markets are independent both technically and as reflected by the production function, they may still be subject to similar external fo[illegible] viz. the international trends, the state of the economy and the general trends in prices. These external forces may be strong enough to generate similar trends over time in the production of both oil and gas.

Table 5-14 (p 176) gives the historical levels of production of oil and of gas in Alberta. Note that the general trends (increases or decreases) are similar. The ratio of gas to oil production does not vary significantly, especially during 1962-1974. These trends are not only evident for Alberta but are reflected internationally. Table 5-15 (p 177) gives the actual world production of oil and natural gas. Note that between 1960-1974, the production of both oil and gas increased steadily. The gas/oil ratio between 1960 - 1964 increased dramatically, but remained relatively stable between 1964 - 1974. Since 1974, while the production of oil fluctuated, the production of gas increased steadily up until 1980. Thus in the '60s and the early '70s due to a general economic boom in the world economy, the production of oil and that of gas increased internationally. Both in Alberta, and around the world, there appears to be a change after 1973, when the oil prices increased substantially. These price increases have lead to a decrease in demand but this decrease has not constrained the production of oil in Alberta after 1974, because of a decline in oil

TABLE 5-14

AlBERTA PRODUCTION OF OIL AND NATURAL GAS
10^6 m3

	Oil	GAS	Gas/Oil Ratio
1960	20.69	11.56	.56
1961	25.05	15.09	.60
1962	26.24	22.07	.84
1963	26.80	24.52	.91
1964	27.79	27.99	1.00
1965	29.19	30.51	1.04
1966	32.17	32.29	1.03
1967	36.67	35.36	.96
1968	39.86	40.43	1.01
1969	45.55	47.27	1.03
1970	52.39	54.44	1.03
1971	56.77	59.59	1.06
1972	67.32	67.96	1.00
1973	83.01	73.59	.88
1974	79.10	73.35	.92
1975	67.51	74.47	1.10
1976	67.51	76.46	1.10
1977	60.51	77.49	1.29
1978	60.01	77.49	1.29
1979	68.51	82.31	1.20
1980	63.02	77.35	1.22
1981	56.97	76.37	1.34
1982	54.38	78.52	1.44

Source: Canadian Petroleum Association, *Statistical Handbook*, 1982

TABLE 5-15

WORLD PRODUCTION OF OIL AND NATURAL GAS
10^6 m^3

	Oil	GAS	Gas/Oil Ratio
1960	1219	476606	390
1961	1300	518050	398
1962	1411	566081	401
1963	1515	592185	390
1964	1638	644293	393
1965	1757	689701	392
1966	1910	743628	389
1967	2052	800075	389
1968	2247	884748	393
1969	2418	968761	400
1970	2656	1073255	404
1971	2806	1160437	413
1972	2955	1225955	414
1973	3236	1299599	401
1974	3263	1329004	407
1975	3099	1330014	429
1976	3367	1393458	413
1977	3480	1411514	405
1978	3521	1457979	414
1980	3458	1655148	478
1981	3237	1645291	508
1982	3082	n/a	n/a

Source: American Petroleum Association, *Petroleum Handbook*, 1982 reserves. Thus the production of oil has decreased since 1974. On the other hand, during the same period, the production of gas has increased. (Note in Alberta, it dropped slightly in 1974). In Alberta part of this increase has been due to a higher price of gas, increased producer incentives and increased access to foreign markets. Government programs to encourage the consumption of gas have also been instrumental in generating an increase in the production of gas. The ratio of gas/oil production for Alberta increased between 1975 and 1978 and then again after 1981. But in much of the period under review it has not varied significantly. Thus our model has captured a positive relationship between the production of oil and of gas.

Of interest is the unit elasticity of production with respect to K_2 (1.09). It appears that producers tend to maintain a given level of production to reserves ratio and hence an increase or decrease in reserves leads to proportionate increase or decrease in production. The production to reserves ratio over 1960 - 1983 varied between a narrow range of 3% to 6% with the exception of 1973 - 1974, and again in 1979 - 1980, when it increased to 7%. Note that these two periods coincide with the dramatic increase in world oil prices.

The production to reserves ratio for gas has varied in an even narrower range than oil· 3% - 5% over 1960 - 1983. But note that the elasticity of production of gas with respect to proved reserves is greater than unity (1.6). We feel that an introduction of a marketability variable (such as MDP) may decrease this elasticity.

<u>Zones</u>. As can be seen from Table 5-16 (p 180), the production equation performs very well for all zones. The coefficients of P_{oil} and P_{gas} are significant for all zones although the elasticities are quite low. The coefficient of C_N is negative and significant for three zones and positive and significant for the other one. MDP is significant and negative for three zones but positive and significant for one.

As opposed to the first data set, the elasticity of production of oil with respect to K_2 is inelastic (and in some cases the coefficient is even negative). This is not surprising, given that the reserves for a field or a pool will generally be established in the earlier phases of discovery and development. In the production phase, there are small reserves additions, and the reserves decrease as the resource is extracted. Thus the causality may be switched. Instead of changes in reserves causing a change in production, we may observe changes in production cuasing a change in reserves. This may generate a negative coefficient. Note that in Plains area which is the oldest area in the province, we have a significant negative coefficient of K_2. On the other hand, in Northern area we have a significant positive coefficient. The coefficients of the other two areas are insignificant.

TABLE 5-16

ELASTICITIES OF OIL PRODUCTION FOR ZONES
(Data Set #2)

	C_N	K_2	P_{oil}	P_{gas}	μ	i	Q_{gas}	$[Q_{oil} - Q_{gas}]^2$	MDP	d_1	d_2	d_3	R^2	$\bar{R}^2$	D.W.	df
PLAINS	-.013	-.0061	.077	-.015	-.004	-.020	.859	.046	-.127	.143	-.003	.198	.99	.98	2.03	51
	(-2.43)*	(-3.68)*	(11.63)*	(-1.42)*			(47.68)*	(46.73)*	(-11.60)*	(18.95)*	(-.154)	(13.0)*				
CENTRAL	.0086	-.0010	.103	-.087	.0028	.013	.965	.050	.008	-.008	.045	.081	.99	.99	1.83	49
	(2.24)*	(-.591)	(3.47)*	(-4.12)*			(46.89)*	(38.74)*	(.161)	(-.28)	(1.18)	(2.36)*				
NORTHERN	-.122	.040	.308	.429	-.040	-.189	.854	.072	-.045	.154	-.07	-.042	.89	.87	.90	52
	(-1.38)**	(1.78)**	(2.51)*	(2.53)*			(7.23)*	(17.40)*	(-1.78)*	(1.98)*	(-.43)	(-.27)				
FOOTHILLS	-.069	-.012	.205	.290	-.023	-.107	1.22	.121	-.047	.142	-.32		.95	.95	1.97	39
	(-2.0)*	(-.98)	(22.83)*	(22.17)*			(23.76)	(23.09)	(-23.80)*	(23.18)*	(-23.76)*					

NOTE: The t-statistics are enclosed in the parenthesis below the elasticity estimates

* indicates that the variable is significant at 95 level of significance.

** indicates that the variable is significant at 90 level of significance.

Fields. Analogous to the case for Alberta and for the separate zones, the production equation does quite well. Table 5-17 (p 182) indicates that almost all variables are significant and of the anticipated sign. Q_{gas} has a positive regression coefficient. The elasticity of oil production with respect to Q_{gas} is close to unity in most cases and the coefficient is significant. MDP consistently appears to be the most statistically significant variable. For fields belonging to the Plains and Central regions, the elasticity with respect to MDP is higher than all other variables. The level of proved reserves (K_2) is significant for all fields in the Northern and Foothills zones, but for the other two zones no consistent pattern is evident. However, the elasticity with respect to K_2 is quite low. This can be explained by similar arguments as put forth for the zones. These arguments will also explain the negative and significant coefficient of K_2 for Turner Valley. Note that Turner Valley is the oldest field in the province. Ricinus and Ferrier which are relatively newer fields have a positive and significant coefficient.

Alberta: Pooled Sample Data. Table 5-18 (p 184) gives the results for equation (4-53) with the fourth set of data. The R^2 is high and all variables except K_2 are significant. However, C_N does not have the anticipated sign. Q_{gas} is positively related to Q_{oil} and the coefficient is significant.

TABLE 5-17

ELASTICITIES OF OIL PRODUCTION FOR FIELDS
(Data Set #3)

	C_N	K_2	P_{oil}	P_{gas}	μ	i	Q_{gas}	$\left(\frac{Q_{oil}}{Q_{gas}}\right)^2$	MDP	R^2	$\bar{R}^2$	D.W.	df
BONNIE GLEN	.048	-.0018	.197	-.101	.016	.074	.92	.050	-.21	.99	.98	1.96	9
	(.365)	(-.468)	(7.82)*	(-3.81)*			(11.88)*	(12.85)*	(-2.54)				
FERRIER	-.144	.0080	.063	.0002	-.048	-.223	.88	.070	-.070	.99	.99	1.79	9
	(-40.97)*	(2.73)*	(10.77)*	(.018)			(33.45)*	(25.26)*	(-37.27)*				
LEDUC	-.025	.00016	.106	-.25	-.008	-.038	.49	.029	-.44	.98	.97	1.97	8
	(-1.37)	(.068)	(3.35)*	(-8.84)*			(11.50)*	(9.39)*	(-9.35)*				
PEMBINA	-.105	.0005	.246	.018	-.035	-.163	.51	.024	-.35	.97	.96	1.87	8
	(-1.59)*	(.019)	(3.30)*	(.27)			(7.58)*	(6.89)*	(-7.78)*				
RAINBOW	-.053	.015	.025	-.027	-.0177	-.082	.98	.051	-.102	.99	.99	2.21	9
	(-14.90)*	(.527)	(1.78)**	(-1.15)			(29.69)*	(30.17)*	(-29.13)*				
RED EARTH	-1.41	-.086	.439	-.49	-.470	-2.18	-	-	-.82	.72	.58	1.26	9
	(-1.76)**	(-.54)	(2.61)*	(-2.62)*					(-1.50)**				
RED WATER	-.202	.0028	.106	-.111	-.067	-.314	.759	.038	-.23	.97	.95	1.39	9
	(-13.82)*	(.473)	(7.04)*	(-3.62)*			(13.00)*	(13.23)*	(-12.50)*				
RICINUS	-.010	.330	.034	.057	-.0033	-.015	.089	.045	-.0037	.88	.86	2.02	9
	(-3.82)*	(3.95)*	(3.70)*	(3.66)*			(3.60)	(1.76)**	(-4.19)*				

Continued

TABLE 5-17: (CONTINUED)

	C_N	K_2	P_{oil}	P_{gas}	μ	i	Q_{gas}	$(Q_{oil} - Q_{gas})^2$	MDP	R^2	$\bar{R}^2$	D.W.	df
SWAN LAKE	.098	-.00052	.22	-.080	.033	.152	1.03	.062	-.028	.99	.99	2.59	9
	(1.89)	(-.076)	(25.12)*	(-5.43)*			(37.41)*	(27.59)*	(-11.75)*				
TURNER VALLEY	-.021	-.010	.052	.080	-.007	-.032	.006	.0006	-.0061	.57	.44	1.82	10
	(-3.34)*	(-1.76)**	(3.34)*	(3.34)*			(3.23)	(.32)	(-3.34)*				
UTIKUMA LAKE	-.187	-.002	.193	-.090	-.062	-.290	.84	.053	-.303	.99	.99	1.44	9
	(-1.95)*	(-.80)	(16.99)*	(-3.12)*			(14.91)*	(30.65)*	(-6.69)*				
VIRGINA HILLS	.215	.00043	.039	0.102	.0717	.334	.97	.057	-.055	.99	.98	1.96	9
	(-18.55)*	(.187)	(4.96)*	(-8.35)*			(20.14)*	(15.56)*	(-19.86)*				
WIZARD LAKE	-.158	-	.086	-.047	-.0527	-.245	.88	.046	-.166	.99	.98	1.34	10
	(-24.58)*	-	(9.36)*	(-2.84)*			(23.42)*	(28.55)*	(-20.28)*				
ZAMA	-.150	.0062	.392	.647	-.050	-.234	.269	.017	-.012	.96	.95	2.53	9
	(-3.58)*	(.180)	(3.56)*	(3.56)*			(3.55)*	(16.34)*	(-3.42)*				

NOTE: The t-statistics are enclosed in the parenthesis below the elasticity estimates.

* indicates that the variable is significant at .95 level of significance.

** indicates that the variable is significant at .90 level of significance.

TABLE 5-18

ELASTICITIES OF OIL PRODUCTION FOR ALBERTA POOLED DATA
(Data Set #4)

	C_N	K_2	P_{oil}	P_{gas}	μ	t	Q_{gas}	$\left(\frac{Q_{oil}}{Q_{gas}}\right)^2$	MDP	R^2	$\bar{R}^2$	D.W.	df
OLS	.585	.0074	-1.10	.415	.195	.908	1.47	.090	.283	.96	.95	.80	202
	(1.92)*	(.991)	(-1.81)*	(1.58)**			(31.69)*	(43.24)*	(1.23)				
PC	.494	.0040	.10	.0625	.165	.767	1.25	.078	-.37	.94	.94	.75	206
	(4.29)*	(.483)	(3.34)*	(.920)			(31.70)*	(43.17)*	(-2.75)*				

NOTE: The t-statistics are enclosed in the parenthesis below the elasticity estimates.

* indicates that the variable is significant at .95 level of significance.

** indicates that the variable is significant at .90 level of significance.

J. Empirical Results: Exploration Sub-Model

$$\text{Log } E = e_0 + e_1 \log RP_{\text{oil U.S.}} + e_2 \log EXP + e_3 \log RP_{\text{alt}} + e_4 \log RE_{t-1} + e_5 \log L \qquad (4\text{-}54)$$

$$\text{Log } EXP = f_0 + f_1 \log \widehat{SU}_E + f_2 \log \hat{P}_{\text{oil}} + f_3 \log \hat{P}_{\text{gas}} + f_4 \log \hat{C}_{E+D} \qquad (4\text{-}55)$$

$$\text{Log } SU_E = g_0 + g_1 \log UDR \qquad (4\text{-}56)$$

As discussed in Chapter IV, the above model is quite simplistic. The first of the equations explains exploratory activity in terms of the price of oil in Alberta relative to that in U.S. ($RP_{\text{oil U.S.}}$); the expected profitability in the oil and gas industry (EXP); the rate of return in alternative industries (RP_{alt}); the level of retained earnings in the oil and gas industry (RE_{t-1}); and the number of acres held (L). The second equation explains the expected profitability in the oil and gas industry as a function of expected success ratio in the oil and gas industry ($\widehat{SU}_E$); the expected wellhead price of oil ($\hat{P}_{\text{oil}}$); the expected wellhead price of gas ($\hat{P}_{\text{gas}}$); and the expected per foot cost of exploration and development ($\hat{C}_{E+D}$). The last equation expresses the success ratio in exploration as a function of the level of undiscovered reserves (UDR).

The above three equation model is estimated for each of the four data sets. The first data set is estimated with both the 3SLS and OLS method of estimation. The other three data sets are estimated only through OLS. This model performs quite well for the first data set (all Alberta) but not so well for the second, third and fourth data sets.

Alberta. The results for Alberta for this model can be seen from Tables 5-19 and 5-20. The results obtained for 3SLS and OLS are similar but differ from those for PC. The PC estimates indicate that all variables are significant at 97% level of significance. The rate of return on alternative investment RP_{alt} has the highest elasticity parameter, followed by the expected profitability, EXP. The OLS and 3SLS method of estimation yield the highest elasticity for retained earnings although, the coefficient is insignificant. All variables under all three methods of estimation are of the anticipated signs.

For equation (4-55), 3SLS and OLS yield unanticipated signs for both $\widehat{SU}_E$ and $\widehat{C}_{E+D}$ although the latter is insignificant. PC yields significant estimates for $\widehat{SU}_E$, $\widehat{P}_{oil}$ and $\widehat{P}_{gas}$ and an insignificant estimate (with unanticipated sign) for $\widehat{C}_{E+D}$.[23]

The results obtained from equation (4-56) are very interesting. We find that for 3SLS and OLS, SU_E is inversely related to the level of undiscovered reserves UDR. Note however that UDR might be interpreted as a trend variable which also captures the effect of the

TABLE 5-19

ELASTICITIES OF A-PRIORI EXPLORATION INVESTMENT MODEL FOR ALBERTA

Data set # 1

3SLS Estimates

$$\text{4-54.}\ \text{Log}\ E = \underset{(-2.44)^*}{-1.7791} + \underset{(1.1899)}{.37093}\ \text{Log}\ RP_{oil\ U.S.} + \underset{(2.6843)^*}{.12387}\ \text{Log EXP} + \underset{(.0000240)}{6.5035}\ \text{Log}\ RP_{alt}$$

$$- \underset{(-2.7929)^*}{.41804}\ \text{Log}\ RE_{t-1} + \underset{(2.8297)^*}{.01353}\ \text{Log}\ L$$

$R^2 = .8511$ $\bar{R}^2 = .8119$ D.W. = 1.3835 d of f = 13

$$\text{4-55.}\ \text{Log EXP} = \underset{(-4.4152)^*}{-7.0533} - \underset{(-3.2418)^*}{2.6044}\ \text{Log}\ \widehat{SU_E} + \underset{(.08406)}{.089272}\ \text{Log}\ \widehat{P_{oil}} + \underset{(2.4403)^*}{1.9130}\ \text{Log}\ \widehat{P_{gas}}$$

$$+ \underset{(.53662)}{.15994}\ \text{Log}\ \widehat{C_{E+D}}$$

$R^2 = .8533$ $\bar{R}^2 = .8224$ D.W. = 1.4379 d of f = 14

$$\text{4-56.}\ \text{Log}\ SU_E = \underset{(7.4124)^*}{155.18} - \underset{(-7.4656)^*}{8.3792}\ \text{Log UDR}$$

$R^2 = .7260$ $\bar{R}^2 = .7166$ D.W. = 1.4319 d of f = 17

System $R^2 = .9563$ Chi-Square = 59.472 d of f = 10

TABLE 5-20

ELASTICITIES OF A-PRIORI EXPLORATION INVESTMENT MODEL FOR ALBERTA
(Data Set # 1)
OLS and PC Estimates

								R^2	$\bar{R}^2$	D.W.	df
	e_0	RP_{oil} U.S. e_1		EXP e_2	RE_{t-1} e_3	RP_{alt} e_4	L e_5				
4-54. Log E (OLS)	-9.2445 (.00001)	.317 (.88)		.139 (2.72)*	1.751 (.00)	-.364 (-2.0)*	.0138 (2.38)*	.85	.797	1.30	13
4-54. Log E (PC)	13.821 (32.4)*	.030 (6.05)*		.170 (5.45)*	.0000 (2.17)*	-3.73 (-2.2)*	.016 (2.7)*	.84	.81	1.16	15
	f_0	$\widehat{SU}_E$ f_1	$\widehat{P}_{oil}$ f_2	$\widehat{P}_{gas}$ f_3	$\widehat{C}_{E+D}$ f_4						
4-55. Log EXP (OLS)	-4.06 (-2.17)*	-1.22 (-1.34)	-.90 (-.74)	2.34 (2.7)*	-.20 (-.716)			.89	.86	1.48	14
4-55. Log EXP (PC)	-.34 (-.32)	.252 (4.69)*	.566 (7.37)*	.775 (8.35)*	.049 (.171)			.84	.82	.85	16
	g_0	UDR g_1									
4-56. Log SU_E (OLS)	160.6 (7.13)*	-8.67 (-7.178)*									
		GWXT									
4-56. Log SU_E (OLS)	-4.19 (-5.35)*	.336 (3.94)*									

existing geology. If UDR is replaced by cumulative number of exploratory wells drilled (CWXT) and assumed that higher CWXT represents diminishing UDR, which is commonly used as a trend variable[24], then our results indicate a positive relation between SU_E and CWXT. The results from the two relations are consistent with each other in that they both indicate that we are on the rising portion of the discovery rate curve.[25] Note that this result could largely be due to the high success ratio obtained in gas or improved search technology for both oil and gas.

Zones. Tables 5-21, 5-22 and 5-23 (p 190, 191, 192) provide the results of this model for each of the four zones. In Table 5-21 the number of acres acquired under the various agreements for drilling purposes, L, (both leases and licenses) is significant in three out of four zones implying that L does impose a constraint on the amount of activity that can be undertaken[26]. This variable has the highest elasticity parameter. EXP is significant for only two zones. Further, in zones where EXP is a significant variable, RP_{alt} is not significant. Equation (4-55) performs relatively better for Plains and Foothills zones. The signs of the coefficients except for $C_{\widehat{E+D}}$ are as anticipated and also most of them are significant. For the Northern zone, the signs of all the coefficients are unanticipated. For the Central zone $\widehat{SU}_E$ and $C_{\widehat{E+D}}$ have unanticipated signs.

The results of equation (4-56) might indicate that in three out of four zones, we are on the decreasing portion of the discovery rate

TABLE 5-21

ELASTICITIES OF A PRIORI EXPLORATION INVESTMENT MODEL FOR ZONES
(Data Set #2; Exploratory Activity)

	Coefficients												
	RP oil U.S.		EXP	RE t-1	RP alt	L	D_1	D_2	D_3	R^2	$\bar{R}^2$	D.W.	df
	e_0	e_1	e_2	e_3	e_4	e_5	e_6	e_7	e_8				
PLAINS	-17.73 (-4.42)*	-.31 (2.16)*	.081 (.269)	.27 (1.17)	-.45 (-1.87)*	2.12 (7.91)*	2.41 (3.75)*	-0.34 (-.88)	1.49 (1.38)**	.68	.65	2.45	50
CENTRAL	3.75 (.249)	.31 (.289)	.27 (1.34)**	-.24 (-.48)	.97 (.47)	.75 (2.13)*	2.40 (3.53)*	-4.84 (-5.47)*	-1.19 (-1.08)	.64	.60	1.88	49
NORTHERN	6.92 (1.80)*	.0046 (.043)	.56 (2.80)*	.172 (.031)	.032 (.361)	-.192 (-.979)	.057 (.69)	-1.86 (-3.04)*	1.76 (2.99)*	.27	.21	1.43	51
FOOTHILLS	1.87 (1.29)	.036 (1.28)	.049 (.193)	.051 (2.86)*	-.019 (-2.91)*	.525 (3.05)*	-.018 (-.44)	-.020 (-1.82)		.21	.17	1.41	39

Note: The t-statistics are enclosed in the parenthesis below the elacticity estimates.
* indicates that the variable is significant at .95 level of significance
** indicates that the variable is significant at .90 level of significance.

TABLE 5-22

ELASTICITIES OF A PRIORI EXPLORATION INVESTMENT MODEL FOR ZONES
(Data Set #2; Expected Profitability)

	Coefficients								R^2	$\bar{R}^2$	D.W.	df
		$\hat{SU}_E$	$\hat{P}_{oil}$	$\hat{P}_{gas}$	$\hat{C}_{E+D}$	D_1	D_2	D_3				
	f_0	f_1	f_2	f_3	f_4	f_5	f_6	f_7				
PLAINS	(-1.90) (-3.10)*	.141 (2.33)*	.22 (2.49)*	.34 (2.47)*	.149 (1.97)*	-.39 (-2.24)*	.42 (1.96)*		.24	.20	1.73	52
CENTRAL	.32 (.22)	-1.19 (-2.79)*	.128 (.80)	.252 (1.00)	.070 (.34)	1.66 (2.91)*	1.72 (2.48)*		.27	.21	2.06	51
NORTHERN	4.58 (2.73)*	-.72 (-1.48)*	-.28 (-1.43)**	-.46 (-1.56)**	.123 (.56)	-.53 (-.93)	-.72 (-1.13)		.10	.03	1.18	51
FOOTHILLS	1.66 (.89)	1.08 (2.10)*	.23 (.96)	.50 (1.28)	.089 (.47)	-1.75 (-1.92)*	-2.11 (-2.02)*		.22	.13	2.09	37

NOTE: The t-statistics are enclosed in the parenthesis below the elasticity estimates.
* indicates that the variable is significant at .95 level of significance
** indicates that the variable is significant at .90 level of significance

TABLE 5-23

ELASTICITIES OF A PRIORI EXPLORATION INVESTMENT MODEL FOR ZONES
(Data Set #2; Success Ratio)

	Coefficients	UDR	D_1	D_2	D_3	R^2	$\bar{R}^2$	D.W.	df
	g_0	g_1	g_2	g_3	g_4				
PLAINS	.036 (.051)	-.023 (-.090)	-.55 (-5.43)*	-.21 (-2.07)*		.36	.32	2.43	52
CENTRAL	.056 (.165)	-.016 (-.240)	-.532 (-3.95)*	.073 (.327)		.42	.39	2.53	52
NORTHERN	-.28 (-2.50)*	-.053 (-1.90)*	.103 (.768)	.171 (1.27)		.10	.05	1.16	52
FOOTHILLS	-.298 (-.33)	.0140 (.090)	.056 (.26)	.024 (.21)		.01	-.06	1.80	38

NOTE: The t-statistics are enclosed in the parenthesis below the elasticity estimates.
* indicates that the variable is significant at .95 level of significance.
** indicates that the variable is significant at .90 level of significance.

curve (as per the Uhler notion). For the Foothills zone, we are still on the rising portion of this curve. However, as the coefficients of UDR are not significant except in the case of the Northern zone, it is difficult to arrive at definite conclusions.

Fields. The alternative model does not perform well for most fields. Equation (4-54) (Table 5-24, p 194 - 195) explains well the timing and extent of exploratory activity only for Pembina, Rainbow, Red Earth, Ferrier, and Ricinus. Note that these are all new fields. Similarly, equation (4-55) (Table 5-25, p 196 - 197) explains the variations in expected profitability for Pembina, Ferrier and Turner Valley. From the results on equation (4-56) (Table 5-26, p 198 - 199) it is again difficult to derive general conclusions.

8. Empirical Results Obtained From Both The Models: A Comparison.

Comparison of the two models can only be made by comparing the results obtained from equation (4-51) with those from equation (4-54). Note that both these equations attempt to explain variations in exploration activity in relation to changes in particular independent variables. Due to wide variations in results obtained from the fields and zones for both the models, we compare only the results obtained for Alberta as a whole, i.e. those from the first data set.

TABLE 5-24

ELASTICITIES OF A PRIORI EXPLORATION INVESTMENT MODEL FOR FIELDS
(Data Set #3; Exploratory Activity)

	Coefficients									
		$RP_{oil\ U.S.}$	EXP	RE_{t-1}	RP_{alt}	L	R^2	$\bar{R}^2$	D.W.	df
	e_0	e_1	e_2	e_3	e_4	e_5				
Bonnie(a) Glen										
Leduc	4.32 (.64)	.076 (.44)	.016 (.019)	.409 (.50)	-.076 (-.506)	.040 (.448)	.025	-.150	1.14	11
Redwater	-4.09 (-.44)	.138 (1.31)	-.128 (-.28)	1.33 (1.23)	-.29 (-1.21)	.165 (1.23)	.18	.038	1.34	11
Wizard(a) Lake										
Judy Creek	25.87 (.45)	-18.51 (-1.39)	.20 (.225)	4.51 (1.17)	9.31 (1.01)	1.37 (.77)	.35	.06	2.35	9
Pembina	1.15 (.34)	.095 (2.06)*	.61 (1.69)**	.39 (4.19)*	-.048 (-1.04)	.202 (.703)	.61	.51	2.05	11
Swan(a) Lake										
Virginia Hill	-	-4.03 (-.38)	.043 (.061)	.153 (.041)	.903 (.140)	-2.24 (-.360)	.08	-.32	1.51	9

Note: The t-statistics are enclosed in the parenthesis below the elacticity estimates.
* indicates that the variable is significant at .95 level of significance.
** indicates that the variable is significant at .90 level of significance.
(a) due to a lack of sufficient observations the results could not be obtained for this field.

TABLE 5-24: (CONTINUED)

	Coefficients									
	RP oil U.S.		EXP	RE_{t-1}	RP_{alt}	L	R^2	$\bar{R}^2$	D.W.	df
	e_0	e_1	e_2	e_3	e_4	e_5				
Rainbow	28.94 (2.45)*	.671 (1.27)	.31 (1.75)**	-.315 (-.79)	2.73 (1.55)**	.0059 (.0458)	.67	.52	2.5	9
Red Earth	40.46 (1.53)**	9.33 (1.61)**	.73 (1.29)	-1.78 (-1.07)	7.91 (1.66)**	2.42 (.83)	.44	.19	3.09	9
Utikume Lake	-10.17 (-.873)	.256 (1.45)**	-.64 (-1.17)	1.57 (1.44)**	-.032 (-1.49)**	.56 (1.50)**	.23	.09	1.67	11
Zama	15.18 (2.20)*	-.262 (-.996)	.71 (2.41)*	-1.14 (-1.06)	.122 (1.47)**	-.175 (-.844)	.61	.50	1.97	10
Ferrier	5.58 (1.41)**	.038 (1.06)	.44 (1.06)	.172 (1.03)	-.020 (-.938)	-.283 (-.084)	.093	-.071	2.30	11
Ricinus	-.271 (-.027)	.175 (.509)	.025 (.062)	.84 (.524)	-.087 (-.603)	.269 (.830)	.172	-.076	1.49	10
Turner Valley	-7.09 (-.84)	.307 (.906)	1.05 (2.47)*	1.36 (.935)	-.131 (-1.189)	.416 (1.22)	.49	.34	2.18	10

TABLE 5-25

ELASTICITIES OF A PRIORI EXPLORATION INVESTMENT MODEL FOR FIELDS
(Data Set #3; Expected Profitability)

	Coefficients								
		$\widehat{SU}_E$	$\hat{P}_{oil}$	$\hat{P}_{gas}$	$\hat{C}_{E+D}$	R^2	$\bar{R}^2$	D.W.	df
	f_0	f_1	f_2	f_3	f_4				
Bonnie(a) Glen									
Leduc	-.66 (-.414)	.087 (.897)	.189 (1.20)	.291 (1.20)	-.0216 (-.097)	.13	-.021	2.49	11
Red Water	-6.37 (-1.80)*	.58 (.170)	.86 (2.55)*	1.52 (2.35)*	.251 (.523)	.62	.50	2.30	10
Wizard(a) Lake									
Judy Creek	-1.03 (-.56)	-.0029 (-1.13)	.039 (1.13)	.0572 (1.13)	.295 (1.13)	.09	.22	2.44	12
Swan(a) Lake									
Virginia(a) Hills									

NOTE: The t-statistics are enclosed in the parenthesis below the elasticity estimates.
* indicates that the variable is significant at .95 level of significance
** indicates that the variable is significant at .90 level of significance
(a) due to a lack of sufficient observations the results could not be obtained for this field

TABLE 5-25: (CONTINUED)

	Coefficients					R^2	$\bar{R}^2$	D.W.	df
		$\hat{SU}_E$	$\hat{P}_{oil}$	$\hat{P}_{gas}$	$\hat{C}_{E+D}$				
	f_0	f_1	f_2	f_3	f_4				
Rainbow	4.33 (.558)	-3.03 (-1.03)	-25.79 (-3.38)*	19.87 (2.65)*	-3.77 (-1.53)**	.72	.60	1.23	9
Red Earth	-.242 (-.092)	-.050 (-1.53)**	-.088 (1.53)**	.15 (1.53)**	.41 (1.53)**	.16	.09	1.24	12
Utikume Lake	4.25 (2.41)*	-.289 (-1.52)**	.52 (1.55)**	.82 (1.55)**	-.57 (-2.17)*	.30	.16	1.72	10
Zama	.186 (.0425)	.176 (2.98)*	-.92 (-2.76)*	-1.40 (-2.71)*	1.01 (2.21)*	.53	.45	1.39	11
Ferrier	1.92 (.627)	2.67 (1.18)	.838 (2.27)*	.817 (1.58)**	-.060 (-.146)	.46	.30	2.13	10
Ricinus	-.359 (-.099)	-6.03 (-1.66)**	-1.21 (-1.67)**	.720 (.65)	.11 (.30)	.28	.06	2.37	10
Turner Valley	-1.05 (-.53)	.436 (3.05)*	1.05 (2.92)*	1.70 (2.93)*	-.62 (-2.26)*	.45	.36	1.73	11

TABLE 5-26

ELASTICITIES OF A PRIORI EXPLORATION INVESTMENT MODEL FOR FIELDS
(Data Set #3; Success Ratio)

	Coefficients		R^2	$\bar{R}^2$	D.W.	df
	UDR					
	g_0	g_1				
Bonnie Glen(a)						
Leduc	-.459 (-2.05)*	-.063 (-.579)	.02	-.05	2.41	12
Red Water	-.282 (-4.12)*	.083 (1.73)*	.20	.13	2.37	12
Wizard Lake(a)						
Judy Creek	.635 (.263	-.118 (-.283)	.006	-.076	2.21	12
Pembina	-10.52 (-1.19)	1.55 (1.13)	.09	.02	2.64	12
Swan Lake(a)						
Virginia Hills(a)						

NOTE: The t-statistics are enclosed in the parenthesis below the elasticity estimates.
* indicates that the variable is significant at .95 level of significance
** indicates that the variable is significant at .90 level of significance
(a) due to a lack of sufficient observations the results could not be obtained for this field.

TABLE 5-26: (CONTINUED)

	Coefficients		R^2	$\bar{R}^2$	D.W.	df
	UDR					
	g_0	g_1				
Rainbow	-1.10 (-.94)	.0827 (.373)	.0115	-.070	.68	12
Red Earth	-.755 (-1.01)	.196 (.619)	.031	-.049	1.14	12
Utikume Lake	-.734 (-2.79)*	.176 (2.01)*	.25	.19	1.87	12
Zama	-.186 (-2.651)*	-.042 (-1.14)	.09	.022	2.04	12
Ferrier	-.147 (-.106)	-.012 (-.050)	.0002	-.0831	2.84	12
Ricinus	1.76 (.97)	-.275 (-1.05)	.084	.008	1.40	12
Turner Valley	-10.52* (-1.19)	1.55 (1.13)	.096	.021	2.64	12

Both equations explain the variations in exploration activity well. Equation (4-51) has an estimated R^2 of .89 and equation (4-54) an R^2 of .84. All the variables in (4-54) are of the expected sign and are significant. For (4-51), the variable C_E, is not significant, and C_D, though significant, is not of the anticipated sign.

The second model suggests that exploration is most sensitive to perceptions of the current rate of return in alternative investments, and to the expected profitability as measured by the unit size of bonus bids in the oil and gas industry. It is less sensitive to $RP_{oil\ U.S.}$, to L (the number of acres acquired under leases and licences) and to RE_{t-1} (the level of lagged retained earnings in the oil and gas industry). The first model suggests that exploration is most sensitive to prices, both of oil and gas. There is one common variable in both the models, i.e. $RP_{oil\ U.S.}$. It has a higher elasticity in the first model, although it is significant in both cases.

As indicated earlier in our theoretical analysis, a comparison of the two models for exploration does not suggest that structural factors play a greater role than financial variables. Both variables play a significant role. Thus although the total amount of land acquired for exploration under the various government agreements places an upper limit on the extent of exploratory drilling, the financial variables also influence the decision to explore or not to explore. Expected profitability in equation (4-55) is explained by expected $\hat{P}_{oil}$, expected $\hat{P}_{gas}$, $\hat{C}_{E+D}$ and $\hat{SU}_E$. Note that as with equation (4-51), $\hat{P}_{gas}$ has a high elasticity. Also, the elasticity of expected profitability with respect to $\hat{P}_{gas}$ is higher than similar elasticity with respect to $\hat{P}_{oil}$.

Footnotes:

1. This limited time frame is due to (a) the difficulty in obtaining data on micro units and (b) the fact that five of the above fifteen fields were discovered later than 1965; and four other fields, though already discovered earlier, did not have any significant activity before 1965. As explained later in Appendix A to select 15 major oil fields, we first classified all major oil fields in the province (as defined by AERCB) into four zones. Then for each zone we selected the first four. In this selection procedure, some fields which were discovered prior to 1965 were not taken into account. Thus the size of the fields rather than the year of discovery were the criterion used to select fields. Note that the micro-analysis (individual fields) in this thesis is restricted to oil fields.

2. Exploratory expenditures and exploratory footage within the areal boundary of an established field are assigned to that particular field. Exploratory expenditures/footage which do not fall under any established field (i.e., are in newer areas) are classified under miscellaneous. Some of these expenditures can later be assigned to a new field - while others remain under this category. A reclassification of these exploratory expenditures under the miscellaneous category would depend largely on the success obtained in these exploratory ventures.

3. Geological Survey of Canada

4. In equation (4-53) and (4-36), there is a one to one correspondence between the right hand variables $[\log Q_{oil} - \log Q_{gas}]^2$ and the dependent variables Q_{oil} and Q_{gas}. As a result, the results obtained from (4-53) and (4-36) may be misleading. We tried to eliminate this problem by replacing the Q_{oil} and Q_{gas} on the right hand side by $\hat{Q}_{oil}$ and $\hat{Q}_{gas}$, where $\hat{Q}_{oil}$ and $\hat{Q}_{gas}$ are predicted values. These are obtained by first regressing Q_{oil} and Q_{gas} separately on all exogenous variables. Second, the estimated equation is utilized to generate $\hat{Q}_{oil}$ and $\hat{Q}_{gas}$. The estimated equations are as follows:

$$\text{Log } Q_{oil} = \underset{(6.090)}{5.2247} - \underset{(-.4069)}{.0508} \left[\log C_N + \log(a + \mu - i) - \log(a - i)\right]$$

$$+ \underset{(14.949)}{.995} \log K_2 + \underset{(.4447)}{.0720} \log P_{oil}$$

$$- \underset{(-4.8139)}{.39549} \log P_{gas} - \underset{(-9.03)}{.6345} \log MDP$$

R^2 = .9898 $\bar{R}^2$ = .9859 D.W. = 2.0497 df = 13

$$\text{Log } Q_{gas} = \underset{(-2.937)}{-4.4991} - \underset{(-.388)}{.11288} \left[\log C_N + \log(a + \mu - i) - \log(a - i)\right]$$

$$+ \underset{(13.519)}{1.6347} \log K_2 + \underset{(.5859)}{.2445} \log P_{oil}$$

$$- \underset{(-1.5681)}{.33039} \log P_{gas}$$

R^2 = .9542 $\bar{R}^2$ = .9411 D.W. = 1.2269 df = 14

5. The assumption underlying any behavioral relationship is the presence of a direct correspondence between dependent and one or more independent variables. In a properly specified model, the macro data captures this direct correspondence. Micro data on the other hand are based on limited information and are of poor quality with low reliability. Therefore, the information contained in the micro data may not be adequate to capture the direct correspondence implied by a behavioral model.

6. An alternative specification with three dummy variables was also experimented with, but the third dummy variable was found to be insignificant.

7. As stated in Appendix A, a major oil field is defined as producing more than 222.6 10^3 m^3 per year. A major gas field is defined as producing more than 222.6 10^3 m^3.

8. See Kmenta (1971), p 371.

9. Some alternative specifications were also experimented with. For example, we tested $E = f(C_E)$ and obtained the following results:

1961 - 1979: $\quad \text{Log } E = 15.11 - .05358 \log C_E$
$\qquad\qquad (19.05)\ (-.245)$

$R^2 = .0035 \quad \bar{R}^2 = -.0551 \quad D.W. = .2039 \quad df = 17$

1974 - 1979: $\quad \text{Log } E = 12.68 + .8731 \log C_E$
$\qquad\qquad (22.91)\ (5.56)$

$R^2 = .88 \quad \bar{R}^2 = .85 \quad D.W. = 3.14 \quad df = 4$

10. See Chapter IV, Section V.

11. Note that due to geological and transport problems which affect the economic viability of any project, most of the drilling in the last two decades has been in the Plains and Central zones of the province.

12. See Maddala (1977), p 134.

13. Normally both the price and cost elasticity of development and production activity will be equal (see equation v in Chapter IV). But since we break the composite price into two components, P_{oil} and P_{gas}, theoretically we get a larger elasticity of development with respect to C_D. However, empirically we find that this does not hold true.

14. The exact regression equation is as follows:

$$\text{Log } D = \underset{(3.74)}{11.143} + \underset{(1.50)}{.253} \text{ Log } K_1$$

$R^2 = .11 \quad \bar{R}^2 = .11 \quad D.W. = .21 \quad df = 17$

15. $$\text{Log}D_t = \underset{(2.73)}{16.793} - \underset{(-1.78)}{.066} (\log C_D - \log \mu + \log (a + \mu - 1))$$

$$- \underset{(-1.35)}{.102} \log K_1 + \underset{(.76)}{.038} \log P_{oil} + \underset{(1.90)}{.066} \log P_{gas}$$

$$+ \underset{(1.15)}{.238} \log RP_{oil\ U.S.}$$

$R^2 = .62 \quad \bar{R}^2 = .57 \quad D.W. = .47 \quad df = 16$

16. This form is general in that the coefficient b_1 which was common to C_D, and i is now divided into its three components. Thus C_D, and $(a + \mu - i)$ have individual coefficients.

17. Similar general specifications were estimated for exploration and production. For exploration, where the term $(\log \mu - \log(a + \mu - i))$ is decomposed, the results are as follows:

$$\text{Log } E = \underset{(25.79)}{12.29} - \underset{(-.67)}{.059} \log C_E + \underset{(2.99)}{.179} \log \mu + \underset{(2.82)}{.055} \log (a + \mu - i)$$

$$+ \underset{(1.04)}{.025}\, i + \underset{(7.72)}{.21} \log P_{oil} + \underset{(8.39)}{.51} \log P_{gas}$$

$$+ \underset{(2.98)}{.217} \log C_D + \underset{(7.95)}{.161} \log RP_{oil\ U.S.}$$

$$R^2 = .87 \quad \bar{R}^2 = .83 \quad D.W. = 1.47 \quad df = 11$$

The general form of equation C' yields the following results:

$$\text{Log } Q_{oil} = \underset{(10.55)}{5.62} + \underset{(.730)}{.0170} \log C_N + \underset{(7.50)}{.160} \log (a + \mu - i)$$

$$+ \underset{(.487)}{.011} \log (a - i) + \underset{(5.45)}{.108} \log K_2 +$$

$$+ \underset{(1.55)}{.067} \log P_{oil} - \underset{(11.47)}{.193} \log P_{gas} - \underset{(-24.33)}{.377} \log MDP$$

$$+ \underset{(36.81)}{.688} \log Q_{gas} + \underset{(3.51)}{.019} \log (\log Q_{oil} - \log Q_{gas})^2$$

$$R^2 = .99 \quad \bar{R}^2 = .99 \quad D.W. = 2.3 \quad df = 10$$

Note that in all three general formulations the goodness of fit and the significance of variables is improved. However, the F-value in both the specifications in all three cases is significant at the .99 level.

18. "The AERCB believes that Alberta market prorationing was largely instrumental in increased competition in the industry and resulted in various discoveries that may not have been made to this time" (AERCB (1983) p. 25).

19. AERCB (1983) p. 26.

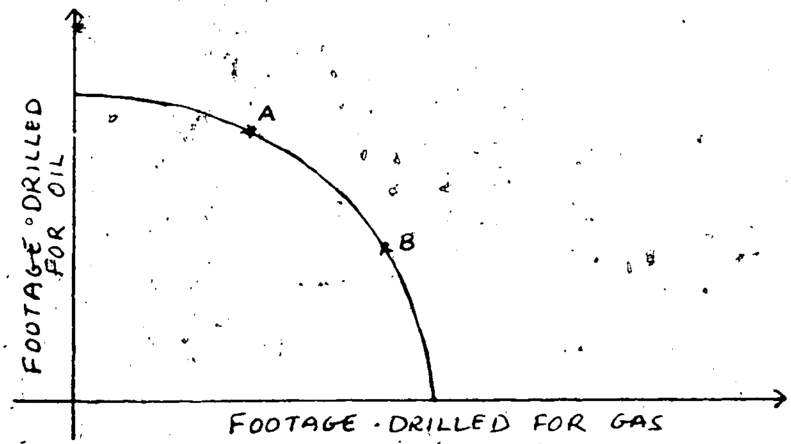
20. Ibid, p. 25.

21. MDP is chosen as the appropriate scaling factor.

22. Thus we may have a tradeoff possibility curve of the shape

Figure 5-2

The Trade-off Possibility Curve Between Oil and Gas



As the price of gas increases we may observe a shift from point A on this curve to point B.

23. Note that we have lumped together both the exploratory and development costs to get a variable which would more adequately represent the cost that determines the profitability of operations.

24. MacAvoy and Pindyck (1974), Uhler (1976, 1979).

25. However, the relationship indicated in footnote 18 of Chapter IV between UDR and SU_E, is not constant. With appreciations in UDR due largely to better information, the curve would shift to the right although the curvature may remain the same.

26. The significance of L may be due to a one to one correspondence between E and L. As discussed earlier in Chapter IV, land acquisition preceeds exploration and may be influenced by similar factors. However, as the aim in the sub model is to analyze the exploratory activity, no separate function is defined, and L is treated as an exogenous variable.

CHAPTER VI: THE SIMULATIONS

In this chapter, we concentrate on further economic interpretations of the quantitative results obtained in Chapter V from the model developed. Given the various elasticity estimates from the previous chapters, we attempt to analyze the impact of hypothesised changes in various public policy parameters on the dependent variables in the model, i.e. on exploration activity, development activity, production of oil and the production of gas. We also measure the effect of such changes in industry activity, on the cash flows of the industry, and of the two levels of government.

This chapter, then, is divided into four sections. Section 1 gives a brief outline of the policy parameters being considered for change in the subsequent analysis. Also, it specifies the method of calculation of each of the cash flows. Section 2 deals with a sensitivity analysis for various public policy assumptions. It begins by outlining the changes introduced in the policy parameters and then indicates the resulting changes in each of the dependent variables, along with the computed cash flow for each of the policy changes. We consider a time frame of 9 years from 1971 to 1979 for sensitivity analysis. Section 3 yields a time series forecast of exploration, development, and production of oil and gas and the associated cash flows for various policy scenarios. It first specifies the assumptions for various scenarios considered in this study and then provides estimates of dependent variables and the cash flow in each of these scenarios. The results under this section can be divided into two parts: the first generates forecasts for 1980-1984. The projected estimates in the sub-section can be compared with the actual estimates; the second projects results for 1985-1994. Finally, the last section discusses the forecasting accuracy of the model.

1. Public Policy Parameters

Chapter 4 indicates that exploration, development and the production of oil and gas are each responsive to changes in prices, cost and market demand prorationing. Prices refer to the wellhead prices net of royalties.[1] Similarly, the cost refers to cost net of various write-offs and allowances. These costs are referred to as effective cost, as compared to actual costs which are gross of any write-offs and allowances. Among the policy parameters considered in the model, net costs, netback product prices and market demand prorationing enter the estimated equations directly, whereas royalties, tax write-offs and allowances enter the model indirectly, i.e. either through prices or costs. Note that as net prices are not entirely determined within the market but are partly subject to regulation, they are also treated as policy variables.

The various tax write-offs and allowances are discussed in detail in Chapter II. However, we briefly repeat the main features of these write-offs and allowances. Two special write-offs, the exploratory expenditure write-off and development expenditure write-off are provided to the resource industries. These write-offs are special in that they allow certain capital outlays to be expensed at an accelerated rate. The rates at which the two types of expenditures can be written off has changed over time. For much of the '60s and early '70s, both the exploratory and development expenditures could be written off up to 100% in the year in which the expenses were incurred, provided the firm generated sufficient profits. In the absence of such profits, these expenses could be carried forward and expensed as soon as the profits were generated. Since 1974, only 30% of the development expenditures could be expensed in one year, although 100% of the exploratory expenditure write-offs could still be expensed. Both exploratory and development expenditures are expected to continue throughout the '80s.

The two special allowances include the depletion allowance and the resource allowance. These are special in that they are over and above the allowances provided to the non-resource industries. Although the depletion allowance existed through the '60s and the '70s, the resource allowance was brought into effect only in 1976. The resource allowance is expected to continue through the '80s, but the depletion allowance under the National Energy Program (NEP) was phased out at the end of 1984. In addition to these tax write-offs and allowances provided by the federal government, the Alberta government operates a system of exploration incentives - the exploratory and geophysical incentives program. The exploratory incentive program was introduced in 1973 and the geophysical incentive program in 1975. Under both these programs qualifying expenditures are reimbursed to about 30%. (However, under the new oil and gas incentive system, both these programs expire on July 31, 1985). Besides these two incentives, since 1982, a new program called the Petroleum Incentive Program (PIP) has been in effect. Though introduced by the federal government, the payments under this program, for investment in Alberta are made by the provincial government.

In revenues, the royalties are collected by the provincial government and the combined corporate income tax by the federal government. Since the introduction of the NEP in 1980, the Federal government has levied a new tax called Petroleum and Natural Gas Revenue Tax (PGRT), which is collected on total revenue net of operating cost. On January 1, 1982, another tax called IORT was levied on oil, although it was suspended from June 1, 1982. IORT was calculated as follows:

$$\text{IORT} = (\text{Actual domestic wellhead price} - \text{old NEP domestic wellhead price}) \times .50$$

With the signing of the Western Accord on March 28, 1985 several changes have been made to the federal energy pricing and fiscal regime. These are illustrated in Section 3.

In the present study, the various policy parameters are calculated as follows:

1. The netback wellhead price of oil, P_{oil}, is calculated as

$$P_{oil} = WP_{oil} - (R_{oil} \times WP_{oil})$$

where WP_{oil} is the per barrel price of oil at the wellhead, and R_{oil} is the average rate (%) of royalty per barrel of oil.

2. Similarly, the netback wellhead price of gas, P_{gas}, is calculated as

$$P_{gas} = WP_{gas} - (R_{gas} \times WP_{gas})$$

where WP_{gas} is the price of gas per '00 Mcf (one hundred thousand cubic feet) at the wellhead, and R_{gas} is the average royalty rate on gas.

3. We calculate the 'effective' per foot cost of exploration (C_E) as

$$C_E = AC_E - (\tau)(\gamma_E)AC_E - (\tau)(DE)AC_E$$

Note that τ is the actual federal corporate income tax rate (applicable to all corporations), γ_E, the exploration expenditure write-off rate, DE the depletion allowance, and AC_E the actual per foot cost of exploration. Due to the presence of the exploratory expenditure write-off allowance, the industry saves in taxes an amount equal to $(\tau)(\gamma_E)\,AC_E$. For example, if τ were 36%, AC_E were \$1.00, and the firms were allowed to write off all the exploratory expenditures (i.e. γ_E was 100%), then the amount saved in taxes would be \$.36. Thus the second term in the above equation measures the total exploratory write-off out of the actual cost, AC_E. By the same reasoning, the third term reflects the total depletion allowance out of the actual cost. It should be noted that the above formulation and the formulations to follow apply strictly to those firms which are in the taxable bracket in a given year.

4. Again, the 'effective' per foot cost of development C_D is calculated as

$$C_D = AC_D - (\tau)(\gamma_D)AC_D - (\tau)(DE)AC_D$$

where, γ_D is the development expenditure write-off rate and AC_D the actual cost of development per foot. In line with 3 above, the second and third terms on the right hand side give the total development write-off, and total depletion allowance respectively.

Finally, the 'effective' cost of operating per '000 BTU of oil and gas is calculated as

$$C_N = AC_N (1 - \tau (1 - RA))$$

where AC_N is the actual cost of operating per '000 BTU of oil and gas and RA is the resource allowance. Note the treatment of RA in this formulation is quite different from the treatment of γ_E, γ_D and DE in the above two formulations. This occurs because γ_E, γ_D and DE are defined over expenditures, and RA is defined over net revenue.

Table 6-1 provides the rates of royalties, allowances and write-offs for the period 1960-1979. Table 6-2 provides the netback prices of oil and gas (net of royalties) as against the wellhead prices for the same period. Finally, Table 6-3 compares the net or effective cost of exploration, development and operating with actual nominal costs.

The cash flow generated within the oil and gas industry is shared between the federal and the provincial governments and the industry itself. The industry's net cash flow is the sum of (a) the net revenue (after costs, royalties and taxes) generated within the oil and gas industry, and (b) the incentive credits earned by the industry. It is thus calculated as,

TABLE 6-1

AVERAGE ROYALTY RATES, WRITEOFFS AND ALLOWANCES FOR THE OIL AND GAS INDUSTRY (1960-1979)

	Average Royalty Rate for Oil	Average Royalty Rate for Gas	Exploration Expense Writeoff Rate	Development Expense Writeoff Rate	Depletion Allowance Rate	Resource Allowance Rate
1960	.120	.150	1.0	1.00	.33	.00
1961	.120	.150	1.0	1.00	.33	.00
1962	.130	.150	1.0	1.00	.33	.00
1963	.130	.163	1.0	1.00	.33	.00
1964	.130	.163	1.0	1.00	.33	.00
1965	.130	.163	1.0	1.00	.33	.00
1966	.130	.163	1.0	1.00	.33	.00
1967	.142	.163	1.0	1.00	.33	.00
1968	.139	.163	1.0	1.00	.33	.00
1969	.139	.163	1.0	1.00	.33	.00
1970	.147	.163	1.0	1.00	.33	.00
1971	.150	.163	1.0	1.00	.33	.00
1972	.150	.163	1.0	1.00	.33	.00
1973	.159	.163	1.0	1.00	.33	.00
1974	.360	.350	1.0	.30	.33	.00
1975	.370	.370	1.0	.30	.33	.25
1976	.389	.402	1.0	.30	.33	.25
1977	.390	.410	1.0	.30	.25	.25
1978	.410	.409	1.0	.30	.25	.25
1979	.400	.407	1.0	.30	.25	.25

TABLE 6-2

WELLHEAD AND NETBACK PRICE OF
OIL AND GAS (1960-1979)
(Cdn. $)

	Average Wellhead Price of oil $/b	Average Wellhead Price of gas $/ 00 Mcf	Average Netback Price of oil $/b	Average Netback Price of gas $/ 00 Mcf
1960	2.29	9.68	1.98	8.19
1961	2.29	11.49	1.98	9.73
1962	2.22	12.20	1.91	10.35
1963	2.36	13.39	2.03	11.18
1964	2.43	13.93	2.08	11.62
1965	2.41	13.70	2.06	11.43
1966	2.39	14.40	2.04	12.01
1967	2.38	14.80	2.01	12.35
1968	2.40	14.80	2.03	12.35
1969	2.42	14.70	2.04	12.26
1970	2.49	15.20	2.09	12.68
1971	2.75	15.00	2.30	12.52
1972	2.77	15.80	2.32	13.19
1973	3.41	17.60	2.73	14.69
1974	5.72	27.40	3.58	17.73
1975	7.18	55.70	4.42	34.90
1976	8.38	86.90	4.99	51.76
1977	10.75	116.38	8.47	68.41
1978	12.75	138.36	7.37	81.55
1979	13.75	158.51	8.10	93.81

TABLE 6-3

ACTUAL AND EFFECTIVE COSTS OF EXPLORATION, DEVELOPMENT AND OPERATING (1960-1979)

($)

	Actual Cost/ft of Exploration	Effective Cost/ft of Exploration	Actual Cost/ft of Development	Effective Cost/ft of Development	Actual Cost of Operating/m^3 of Oil and Gas	Effective Cost of Operating /m^3 of Oil and Gas
1960	51.69	23.49	23.00	10.45	2.73	1.74
1961	51.35	23.34	31.00	14.09	2.27	1.45
1962	48.00	25.01	25.00	13.03	2.18	1.39
1963	47.54	26.67	28.00	15.71	2.32	1.48
1964	57.73	36.23	27.00	16.96	2.23	1.42
1965	68.97	59.73	22.00	19.07	2.15	1.37
1966	81.08	70.29	26.00	22.56	2.12	1.36
1967	93.00	69.69	34.00	25.40	2.07	1.32
1968	74.57	57.71	47.00	36.37	2.10	1.34
1969	73.97	61.18	48.00	39.70	2.01	1.29
1970	63.36	46.50	56.00	41.10	1.95	1.25
1971	63.44	49.09	79.00	61.13	2.19	1.40
1972	57.91	40.06	85.00	60.12	2.26	1.45
1973	59.01	39.38	55.00	36.71	2.36	1.51
1974	80.08	32.15	43.00	28.87	2.82	1.80
1975	95.59	40.92	54.00	37.06	3.98	2.54
1976	102.41	42.98	64.00	43.44	5.36	2.57
1977	170.78	76.85	76.00	52.83	5.91	2.83
1978	190.78	97.72	75.00	55.69	7.29	3.49
1979	235.69	120.79	88.00	65.69	8.36	4.01

Industry's Cash flow_t

= Total Revenue_t (PQ) - total Operating Cost_t

- total Exploratory Cost_t - total Development Cost

- total federal corporate income tax

- total provincial corporate income tax

+ exploratory incentive credit

+ geophysical incentive credit

+ petroleum incentive credit.

Note that as P is the netback price, i.e. net of royalties plus taxes (excluding the corporate income tax), we do not subtract the royalties separately. After 1982, PGRT is included in the calculation of the netback price. Also, note the costs here are net of tax allowances, i.e. costs are total 'effective'. As the petroleum incentive credit was only introduced in 1982 it does not enter the cash flow calculations for the years between 1970-1979.

The cash flow accruing to the provincial government is comprised of the provincial income tax and the royalties after the payments of incentive credits. We calculate it as,

Provincial Cash Flow_t

= Total Provincial Corporate Income Tax

for the oil and gas industry_t + royalties_t

- exploratory incentive credit_t

- geophysical incentive credit_t

- petroleum incentive credit_t

The provincial corporate income tax is calculated as

$$\text{Provincial Corporate Income Tax} = (\text{Federal Corporate Income Tax Base} + \text{Resource Allowance} - \text{Royalties}) \times \tau_p$$

where τ_p is the actual average provincial corporate tax rate assessed on the above tax base. Note that the provincial corporate income tax is calculated on the same base as the federal corporate income tax, except that there is no resource allowance and that royalties are non-deductible. Since 1975, when resource allowance was introduced, royalty deductions were disallowed from the calculation of the federal income tax base. Royalties are still deductible from the provincial income tax calculations. The federal corporate income tax base is calculated as given below. The resource allowance is calculated on net revenue after subtracting the capital cost allowance, but before deducting royalty payments.

Finally, the federal government's cash flow consists of the petroleum and natural gas revenue tax (PGRT), the incremental oil revenue tax (IORT) and the federal corporate tax. Thus,

$$\text{Federal Cash Flow}_t = \text{PGRT} + \text{IORT} + \text{federal corporate income tax}_t$$

The federal corporate income tax is calculated as, Federal Corporate Income Tax

$$= ((\text{Total Revenue} - \text{Operating Cost}_t - \text{CCA})$$
$$- \text{RA} \times (\text{Total Revenue} - \text{Operating Cost} - \text{CCA})$$
$$- \gamma_D \times \text{total development expenditure}_t$$
$$- \gamma_E \times \text{total exploratory expenditure}_t$$
$$- \text{DE} \times (\text{total exploratory} + \text{total development expenditures})) \times \tau_F$$

Note the costs are total actual costs i.e. gross of any allowances. CCA is the capital cost allowance which is applicable to any industry depending on fixed assets, and τ_F is the actual federal corporate income tax rate.

The cash flows in the next two sections are calculated according to the above formulae.

2. Sensitivity Analysis

The effectiveness of various public policy parameters applicable to any major segment of the petroleum industry has often been debated. Much of this debate has centered around the consequences of a changed policy environment. Naturally enough, industry spokesmen have generally argued for higher oil prices and/or reduced royalties. Regarding prices, the industry has argued that Canadian domestic prices should be brought into line with world prices. Following the decision of the OPEC cartel in 1973, the price of oil increased four fold in 1974 (from U.S.$ $2.47/barrel to $10.97/barrel). Prices then increased gradually until 1980, when there was again a twofold increase (from $13.66/barrel in 1979 to $28.51 in 1980). However, Canadian domestic prices did not increase to the same degree. In 1974, the Canadian price of oil was roughly 50% of the international price. In 1980 the domestic price was again half of the international price.

Moreover, with respect to taxes and royalty matters, industry spokesmen have often compared the Canadian industry with the U.S. oil and gas industry, and it is claimed that the former is faced with higher tax rates than the latter.

Despite the arguments of the industry and support from provincial governments, the federal government until the 1981 energy agreement did not change the pricing policies for oil. Nor did the provincial government reduce royalty rates at the industry's request. Instead, the industry has been partially compensated by a lucrative package of special incentives, credits and allowances.

However, from the policy point of view questions such as what would the industry investment be if the Canadian prices had equalled the world levels; or alternatively what would be the level of investment under reduced royalties; or what would be the impact on investment and production if the special incentives package was withdrawn are important. Some of these possibilities are pursued in the following analysis.

As major changes in the oil and gas industry occurred only in the '70s (as opposed to the '60s) we select a period of nine years from 1971 to 1979. Four cases with a total of five variations are specified. In each of these alternative cases we change one of the policy parameters assuming that everything else is constant. The effect of each of these changes on exploration, development and production activity in Alberta's oil and gas industry, and the associated cash flows of the industry as well as the two levels of governments, is then studied separately.

(i) Sensitivity Scenarios. The scenarios specified, and the assumptions made in each one of them, are as follows:

Case 1: Case 1 assumes lower royalty rates for both oil and gas as applied to actual regulated domestic prices over the period. We specify two subcases, i.e. .50 and .25 of the actual Alberta royalty rates.

Case 2: The second case assumes that all through the test period (1971 -1979) the domestic wellhead price of oil is equal to the Montreal price of offshore crude minus the transport cost from Alberta to Montreal. This implies that the wellhead price of oil in Alberta throughout the period would have been lower than the actual wellhead price in 1971, 1972 and 1973, and higher for the years 1974-1979.

Case 3: The third case assumes that there are no production restrictions, and firms therefore are producing at full capacity. Thus the MDP parameter measured as a ratio of productive capacity to actual production is 1 for the test period.

Case 4: Case four assumes a complete absence of the earned depletion allowance. The actual rates of the various allowances, write-offs and prices are given in Tables 6-1 and 6-2.

The results derived for each of the above cases are given in Tables 6-4 through 6-10. Column 1 in each of these tables gives the actual annual figures for the particular dependent variable treated in that table (exploration, development, production of oil and gas and cash flow). Column 2 gives the values as generated from our model, assuming no hypothesised changes from 1971 to 1979. Columns 3 through 5 give the projected values for the dependent variable as a result of a hypothesised policy assumption - everything else being unchanged. Each column corresponds to one of the four policy variations discussed above, and assumes that each one of these changes was introduced by itself in 1971, and sustained thereafter, without any change in the other nine years.

However, before deriving the sensitivity estimates as set out, we made a further change in equation 4-51 (exploration) for the following reasons: the results of Chapter V indicate that the cost of development per foot drilled C_D (which is an independent variable in equation 4-51), is positively correlated with E (exploratory footage drilled). Thus, with increases in C_D, E would increase too. Because of this seemingly anomalous result, the movement in E is contrary to what we might expect from economic theory. For example, a decline in the federal development expenditure write-off rate would increase the effective unit cost of development drilling, and this would increase E. In the original specification then, if the government reduces or withdraws its special allowances on development, investment in exploratory phase of the oil and gas industry would increase, and a change in these allowances or write-offs would seem to lead to the opposite of what was intended.

Because of the anomalous sign of C_D in equation (4-51), we re-estimate the equation without C_D. Thus the equation now becomes,

$$\begin{aligned} \text{Log } E = a_0 + a_1 \log C_E + a_2 \log\, (\mu - \log(a + \mu - i)) \\ + a_3 i + a_4 \log P_{oil} + a_5 \log P_{gas} \\ + a_6\ RP_{oil\ U.S.} \end{aligned}$$

Further, we use the reduced form equations of (4-53) and (4-36). Thus Q_{gas} or Q_{oil} and $(Q_{oil} - Q_{gas})^2$ no longer appear on the right hand side of the equation. Both these changes, however, do not affect the results, both in terms of the goodness of fit of the model and the significance of the variables[3].

In analyzing the results obtained from the various sensitivity runs we divide the rest of this section into two parts: predictions for investment and production of oil and gas, and the cash flows of the industry and the two governments.

(ii) Sensitivity of Exploration, Development and Production. The results given in Table 6-4 (exploratory activity) indicate that out of all the policy options considered, on average a move towards the World prices (case 2) would have yielded the highest level of exploration. Between 1970 and 1979, exploration activity would have increased by 31% (compare column 5 and 2). Note the comparisons made in this section and the one to follow are between the mean projected values and the mean value of the case in question.The lowest level of investment in exploration would have been achieved in the case with no depletion allowance (case 4) . However, here exploratory activity changes by only .63%. This modest change is due basically to low cost elasticities. Table 6-5 indicates that, as in the case of exploration, investment in development activity would have been highest had the price of oil moved to world levels. In this instance, development activity would have increased by 35.29% (compare columns 5 and 2). Development activity is lowest when the depletion allowance is eliminated. A decline of 4% is evident (compare columns 7 and 2). If the royalty rates on both oil and gas were halved as hypothesized (Case 1), exploration would have increased by 19%, and development by 27% (compare columns 4 and 2).

Tables 6-6 and 6-7 respectively give the production of oil and of gas under the various policy scenarios. We see that the production of oil is the highest under the third policy option, i.e. with no market demand prorationing (see columns 6 and 2). The production level over the 9 year period is 15% higher under this policy option. The production of gas is highest under Case 2. An increase of 18% is observed (columns 5 and 2). Note that this increase however, would be subject to market outlets. Like exploration and development, Q_{oil} and Q_{gas} do not change significantly in response to change in the depletion allowance. In the present model the changes in E and D are carried over to Q_{oil} and Q_{gas} through changes in K_1 (level of probable reserves) or K_2 (level of proved reserves). Note that $\dot{K}_1$ is a function of E, and $\dot{K}_2$ is a function of K_1, D and Q.

When comparing the overall effects of the various policy options on the three activities, it can be seen that an increase in netback price either through decrease in royalties or increase in the absolute price generates a tremendous increase in investment activity (E and D). The production responds more to the availability of markets as indicated by the coefficient of MDP. Note that Q_{oil} and Q_{gas} have insignificant price coefficients for P_{oil}. The P_{gas} has a significant regression coefficient but a perverse sign. Note as mentioned earlier in Chapter V, P_{oil} and P_{gas} are highly correlated thus distorting the relationships to be captured in the model. A negative coefficient for P_{gas} dampens the effect of reduced royalties of both oil and gas, on Q_{oil} and Q_{gas}. The

TABLE 6-4

SENSITIVITY ANALYSIS: FORECAST RESPONSE IN EXPLORATORY ACTIVITY
('000 foot)

	Actual Values	Predicted Values	Case 1 Lower Royalty .175 of existing Oil and Gas	Case 1 Lower Royalty .50 of existing Oil and Gas	Case 2 World Prices	Case 3 No MDP	Case 4 No Depletion
1971	4299	4676	4845	5013	5836	4676	4703
1972	5140	4776	4949	5120	5787	4776	4815
1973	5877	4783	4999	5215	7264	4783	4829
1974	5155	5306	5902	6483	10210	5306	5339
1975	4773	5866	6559	7235	9292	5866	5906
1976	6421	5891	6654	7395	8894	5891	5930
1977	7602	8578	9138	9682	10750	8578	8622
1978	9109	8409	9578	10712	8007	8409	8455
1979	10079	9641	10933	12187	9819	9641	9694
Mean (1971-1979)	6495	6436	7062	7671	8429	6436	6477

TABLE 6-5

SENSITIVITY ANALYSIS: FORECAST RESPONSE IN DEVELOPMENT ACTIVITY
('000 foot)

			Case 1 Lower Royalty		Case 2	Case 3	Case 4
	Actual Values	Predicted Values	.75 of existing Oil and Gas	.50 of existing Oil and Gas	World Prices	No MOP	No Depletion
1971	3712	3966	4161	4356	4895	5222	3886
1972	4927	4429	4642	4856	5150	5272	4303
1973	6729	5892	6223	6854	8599	6363	5694
1974	6805	6440	7404	8372	13439	6987	6097
1975	7180	7972	9222	10476	11695	9385	7569
1976	9537	8592	10072	11556	10437	10454	8145
1977	9597	11163	12391	13592	13506	13338	10727
1978	10983	9349	11034	12719	11246	11130	9031
1979	12594	11593	13589	15583	14922	11772	11199
Mean (1971-1979)	8007	7711	8749	9818	10432	8880	7406

TABLE 6-6

SENSITIVITY ANALYSIS: FORECAST RESPONSE IN PRODUCTION OF OIL
('000 m^3)

	Actual Values	Predicted Values	Case 1 Lower Royalty .75 of existing Oil and Gas	Case 1 Lower Royalty .50 of existing Oil and Gas	Case 2 World Prices	Case 3 No MDP	Case 4 No Depletion
1971	56780	55256	55080	54916	41821	72499	55107
1972	67324	62613	62597	62586	49967	74434	62446
1973	83013	71801	72030	72248	57118	75545	71568
1974	79108	78728	77182	75930	66940	85351	78427
1975	67511	57980	57500	57143	64506	68091	57627
1976	60742	54324	54114	54011	66671	65910	53961
1977	60514	57692	57373	57196	69364	68784	57286
1978	60015	57864	58161	58486	67908	68741	57527
1979	68516	70107	71020	71876	85294	71256	69774
Mean (1971-1979)	67158	62929	62784	62710	63288	72290	62636

TABLE 6-7

SENSITIVITY ANALYSIS: FORECAST RESPONSE IN PRODUCTION OF GAS
('000,000 m^3)

	Actual Values	Predicted Values	Case 1 Lower Royalty .75 of existing Oil and Gas	Case 1 Lower Royalty .50 of existing Oil and Gas	Case 2 World Prices	Case 3 No MDP	Case 4 No Depletion
1971	59592	55172	55925	56658	44420	55331	54947
1972	67967	57196	58235	59249	49142	57362	56965
1973	73609	61005	62517	63991	54991	61146	60705
1974	73353	69128	70561	71988	74071	69229	68728
1975	74463	60219	62793	65252	83012	60286	59665
1976	75238	63177	66751	70160	91582	63270	62539
1977	78520	74457	77905	81250	100000	74593	73665
1978	77353	76248	81854	87166	100000	76390	75577
1979	81997	80787	87669	94195	110000	80937	80206
Mean (1971-1979)	73566	66377	69357	72212	78580	66505	65889

change in the depletion allowance or changes in effective costs does not change the three activities significantly.

(iii) Cash Flows: Tables 6-8 through 6-10 summarize the cash flows of both the governments and the industry computed by using the method outlined in Section 1. Due to increased prices and royalties, the cash flows of both the governments increase tremendously after 1973, in absolute amounts. On the other hand, the cash flow of the industry declines in 1974. Of all the cases compared, the federal and provincial revenues are highest under Case 2 (world prices) and least under Case 1 (lower royalty). The industry revenue is highest under Case 1 with .50 of existing royalties. Note the industry revenue calculated here is gross of exploration and development outlays. Revenue net of these outlays may be negative depending upon the reinvestment levels.

Table 6-11 illustrates the revenue sharing in the oil and gas industry under the various policy options. In all cases, the industry enjoys the largest share. The federal government has the least share. Royalty revenue constitutes a big part in the provincial revenues and therefore, the provincial government's share is highly sensitive to Case 1. Under Case 2, Case 3 and Case 4, the relative shares are fairly stable. The model projects the relative shares quite accurately - 17, 38 and 45% as opposed to the actual estimates of 18, 38 and 44%. Because the former are based on the projected rather than actual values of E, D, Q_{oil} and Q_{gas}, it reflects the

TABLE 6-8

SENSITIVITY ANALYSIS: FORECAST RESPONSE IN FEDERAL REVENUE
($ '000,000)

	Actual Values	Predicted Values	Case 1 Lower Royalty .75 of existing Oil and Gas	Case 1 Lower Royalty .50 of existing Oil and Gas	Case 2 World Prices	Case 3 No MDP	Case 4 No Depletion
1971	77	62	57	52	27	91	87
1972	120	100	99	93	62	130	140
1973	270	230	230	220	220	250	270
1974	1000	1000	940	890	1800	1100	1100
1975	1300	960	910	870	2100	1100	1100
1976	1000	850	810	760	1600	1000	970
1977	1200	1000	960	910	1800	1200	1200
1978	1100	1200	1100	1000	2000	1400	1300
1979	1300	1300	1300	1200	3300	1300	1600
Mean (1971-1979)	819	745	711	666	1434	841	863

TABLE 6-9

SENSITIVITY ANALYSIS: FORECAST RESPONSE IN PROVINCIAL REVENUE
($ '000,000)

	Actual Values	Predicted Values	Case 1 Lower Royalty .75 of existing Oil and Gas	Case 1 Lower Royalty .50 of existing Oil and Gas	Case 2 World Prices	Case 3 No MOP	Case 4 No Depletion
1971	210	200	160	110	160	250	210
1972	260	230	180	140	200	270	250
1973	460	390	320	240	410	420	410
1974	1300	1300	1000	720	2200	1400	1300
1975	1700	1400	1100	810	2700	1600	1400
1976	2200	1900	1500	1100	3200	2100	1900
1977	2300	2100	1700	1300	3200	2300	2100
1978	3400	3400	2700	2000	4800	3700	3400
1979	4100	4200	3400	2500	7300	4200	4200
Mean (1971-1979)	1770	1680	1340	991	2686	1804	1686

TABLE 6-10

SENSITIVITY ANALYSIS: FORECAST RESPONSE IN INDUSTRY REVENUE
($ '000,000)

			Case 1 Lower Royalty		Case 2	Case 3	Case 4
	Actual Values	Predicted Values	.75 of existing Oil and Gas	.50 of existing Oil and Gas	World Prices	No MDP	No Depletion
1971	780	770	820	870	770	950	210
1972	920	850	910	960	850	970	250
1973	1200	1000	1100	1200	1300	1100	410
1974	950	940	1200	1500	1700	1000	1300
1975	1100	1100	1500	1900	1900	1200	1400
1976	1900	1700	2200	2800	2800	1900	1900
1977	3400	3400	4000	4600	4900	3800	2100
1978	3500	3300	4300	5300	4100	3600	3400
1979	4500	4400	5700	7000	6400	4500	4200
Mean (1971-1979)	2028	1940	2414	2903	2747	2113	1686

TABLE 6-11

FORECAST REVENUE SHARING IN THE OIL AND GAS INDUSTRY
(1971-1979)

	Actual	Predicted		Case 1 Lower Royalty	Case 2	Case 3	Case 4
			.75 of existing Oil and Gas	.50 of existing Oil and Gas	World Prices	No MOP	No Depletion
	%	%	%	%	%	%	
FEDERAL	18	17	15	15	21	18	20
PROVINCIAL	38	38	30	22	39	38	40
INDUSTRY	44	45	55	63	40	44	40

accuracy of the model.

3. Forecasting Analysis.

Forecasting by nature is very sensitive to the assumptions made about the exogenous or predetermined variables. There are many sources of uncertainties - some that we expect and some that are unexpected. The inclusion of these uncertainties is often difficult although they do affect the forecasts. Thus the forecasts may not be very accurate. Nevertheless, these forecasts are often interesting and insightful as to what would happen if the assumptions turned out to be valid over the forecast period.

Much debate over the last few years has centered on the effects on the petroleum industry of the National Energy Program (NEP) introduced in Canada on Oct 28, 1980. The enormous amount of effort directed towards this debate by the industry and by provincial governments is well deserved for two reasons: Firstly, the energy (oil, gas and coal) industry contributes a significant amount to the Alberta GNP, and any adverse effects on the industry would hamper the provincial growth rate (in 1970, the oil and gas industry contributed 42% of the provincial GNP and in 1981 it contributed 34%.) Secondly, with the onset of recession, any unnecessary setback to a vibrant industry could simply deepen the recession. Following strong opposition from both the industry and the provincial government, the

NEP of Oct, 1980 was modified, and a provincial - federal agreement was reached on Sept 1, 1981, although even this agreement was very favourable to the federal government. In this section, we ~~bri~~efly state the features of the NEP - both the 1980 program and the subsequent change in 1981. Later in this section, the highlights of the newly signed Western Accord are also included. Further, we state the changes introduced by the new provincial Oil and Gas Incentive Program. All this provides a framework under which the forecasts are made in this section.

(i) The NEP: 1980 and 1981: The NEP of 1980 contained substantial changes for pricing and fiscal measures. The program introduced three distinct price series for the wellhead price of oil. Conventional oil was fixed at $14.75 per barrel, with increases of $1.00 every six months until the end of 1983. Thereafter the price was to increase by $2.25 every six months until the end of 1985, and then by $3.50 every six months. The oil sand reference price was fixed at $38.00 per barrel in Jan, 1981, with increases to $41.85 in Jan, 1982 to $45.80 in Jan, 1983, and further at preset rates. This price was subject to a cap of not more than 100% of the price of imported crude in Montreal. Tertiary recovery oil was fixed at $30.00 per barrel on Jan, 1981, with increases to $33.05 in Jan, 1982, to $36.15 in Jan, 1983, and then again at a prespecified rate. The last two price categories related to high cost oil.

According to the program, although producers received the above wellhead prices, the Canadian consumers paid a separate price. The price, more commonly referred to as the blended or 'made in Canada' price, was derived by adding a petroleum compensation charge to the domestic wellhead price. It was proposed that this price would not increase to more than 85% of the international price.

Since 1975, the price of gas had increased by 15¢ per Mcf for every $1 increase in the price of crude oil. Commencing Nov 1, 1980, the price of gas was to increase by 45¢ per Mcf per year resulting in a 65% parity (in BTU terms) to the blended price of oil outlined in NEP, 1980. These price increases were applicable only to gas being traded between the provinces. Within the provinces of Alberta, British Columbia and Saskatchewan, the price of gas being produced and consumed in the province has been determined by the provincial government.

The fiscal measures that were introduced or modified included the petroleum compensation charge, the natural gas tax, the oil export charge, and the petroleum and gas revenue tax. The petroleum compensation charge was specified in the NEP (see The National Energy Program, October 28, 1980 p 30) - it was $2.55 in Dec 1981, and increased to $5.05 in 1982, to $7.55 in Dec 1982, and to $10.05 in Dec 1983. This charge, although imposed to cover import subsidies being provided to oil importers, could generate net revenue for the federal government as early as the end of 1982, on the assumption that international prices rose slowly. A natural gas tax at the rate of 30¢ per Mcf was imposed on Nov 1, 1980. This tax was increased by 15¢ on July 1, 1981 and then by another 15¢ every six months until Jan 1, 1983. The oil export charge, which was equivalent to the difference between the domestic price and the export price of oil, was to continue, but the revenue was now to be shared equally between the federal and the provincial governments. The petroleum and gas revenue tax was introduced at a rate of 8% of net operating oil and gas revenues, but this was to increase when the price of oil increased by more than $1.

Besides the above measures, the federal government also introduced some changes in the then-existing incentive structure. First, the earned depletion allowance applicable to exploration and development expenditure was to be phased out by 1984. It was to be reduced from 33% in 1981 to 20% in 1982, and to 10% in 1983. However, the depletion allowance on synthetic oil production from oil sands was maintained. Second, the federal government introduced a petroleum incentives program which partially compensated for exploratory and development expenditures. The extent of compensation depended primarily on the extent of Canadian ownership.

As stated above, although the NEP was introduced to increase activity in the industry and also provide 'equitable' sharing of revenues between the federal and provincial governments, the program received heavy criticism from the industry, the provincial government and energy specialists. The result was that the original NEP was modified by an agreement reached between the government of Alberta and the federal government. Changes were introduced in both the pricing and the tax measures. Two sets of price series for oil were introduced - one was for conventional old oil which was to increase from $18.75 per barrel in July 1981, to $21.25 in Oct 1981, to $23.50 in Jan 1982, and to $25.75 in July 1982. After that, the price of conventional old oil was to increase by $4.00 per barrel every six months. This price was subject to a ceiling of 75% of international prices. The second set of prices covered new oil, incremental oil (i.e. enhanced recovery oil), and synthetic oil. New conventional oil was defined as oil discovered after Dec 31, 1980. This category of oil price was subject to a ceiling of 100% of the international oil price.

The modifications introduced in the tax and incentive structure were as follows. The petroleum compensation charge was to be modified in such a way that it could only pay for import subsidies and for higher prices paid to domestic production receiving the world equivalent price, and not generate net revenues for the federal government. The natural gas and gas liquids tax was reduced to zero for natural gas exports, but was to continue on exports of propane and butane and also on the domestic production of natural gas. The petroleum and gas revenue tax increased to 16% (effectively 12% due to the resource allowance) of the net oil and gas revenues, and this tax was decreased to 10.7% on Alsands and Cold Lake synthetic production.

A new tax called the incremental oil revenue tax (IORT) at the rate of 50% of the difference between the new NEP price and the old NEP price was introduced, although it was later reduced to zero between June 1, 1982 and May 31, 1983. Another change affected the Petroleum Incentive Payment (PIP) - the Alberta government agreed to administer and pay the incentives applicable within the province.

Following the 1981 agreement, there was an update of NEP in 1982, which did not bring about significant changes. The NORP was extended to tertiary recovery projects, experimental projects, and suspended wells. The earned depletion was extended to tertiary projects.

The provincial government in order to mitigate some of the negative impact of the NEP, brought several changes to its incentive structure. The royalty tax credit program which had been in effect since May 6, 1974, which provided a credit of 25% of royalties to a maximum of $1 million, was enriched to 75% of royalties to a maximum of $4 million. This change was effective between September 1, 1981 to December 31, 1983. Effective January 1, 1984, the royalty tax credit rate was changed to 50% of royalties to a maximum of $2 million. A new one year royalty holiday for exploratory drilling was introduced on April 1, 1984. A one year natural gas royalty holiday for certifiable wells was introduced in 1982, and was later extended to 3 years. Another program called the Development Drilling Incentive System (DDIS) was brought into effect on August 15, 1982. Under this program, the firms were reimbursed approximately 25% of their drilling costs. The DDIS expired in September, 1983. Further to above, special incentives in terms of royalty relief packages have been in effect since October, 1982.

<u>(ii) Western Accord and the New Provincial Oil and Gas Incentive Program</u>: Major changes in the regulatory structure governing the energy industry have been introduced recently by the Western Accord signed on March 28, 1985. The Accord abolishes the regulated pricing of oil effective June 1, 1985. The price of oil will now be determined through negotiations between the buyer and the seller. The Alberta Border Price of natural gas is to be frozen at its current level of $3.00/G.J. until November 1, 1986 when a new pricing scheme is to be brought into effect.

The NGGLT, IORT, Cost of Service Charge (COSC), Crude Oil Export Charge, PCC are terminated as of June 1, 1985. PIP is to continue until March 31, 1986 and PGRT is to be phased out by the end of 1988. Further, no PGRT will be charged on production out of wells drilled after April 1, 1985.

On June 24, 1985, the Government of Alberta announced a new oil and gas incentive package. Under this program, the exploratory and geophysical incentive programs and one year royalty holiday for oil wells, will expire on July 31, 1985. Alberta Petroleum Incentive Program will expire at the end of March 31, 1986 together with the Federal PIP. On the positive side, marginal royalty rates on both oil and gas will be reduced in stages over a 24 month period from 45% to 40% on old production and from 30% to 25% on new production. The Royalty Tax Credit to small producers will be increased to 75% of royalty payments to a maximum of $3 million, effective April 1, 1986. A new one year royalty holiday program for oil and for shallow exploratory gas wells is also brought into effect starting June 1, 1985. Both these royalty holiday programs are to exist until May 31, 1988. Under the oil royalty holiday program, the firms can obtain a maximum of $1 million per well and under the gas royalty holiday program a maximum of $2 million per well. Finally a royalty holiday program covering all deep gas wells drilled was also introduced on June 1, 1985.

(iii) Future Trends: The spirit surrounding the oil and gas industry has changed since the introduction of the Western Accord. The tax changes, especially the termination of PGRT is expected to provide extra cashflow to the industry to reinvest. Besides, the abolishment of IORT, COSC, PCC eliminates the uncertainty and negativism that has surrounded the industry since the introduction of NEP in 1980.

The de-regulation of prices may not bring a positive impact on activity largely because although COOP will now get a higher price, NORP will be substantially reduced, due to a downslide in the World prices. In the next decade, the general consensus in the industry is that the world prices will either remain constant in real terms or change at minimal rates in real terms.

The oil and gas market deregulation would further help to alleviate problems of shut-in capacity, of course subject to market availabilty. For the Alberta petroleum industry, the abolition of PIP on the frontier exploration would bring the investment dollars back into the province.

The net impact of both the Western Accord and the changes in the provincial fiscal structure is that the investment in the province is expected to increase. Although the total investment may increase, there may be a switch from investment in conventional reserves to investment in non-conventional and enhanced recovery projects.

(iv) Forecasting Scenarios. Similar to Section 2, we analyze the effect on the investment, production and cashflows of various forecasting scenarios. The cashflows are calculated in the same fashion as illustrated in Section 1. We select a period of 15 years which is divided into two parts: 1. 1980 - 1984; 2. 1985 - 1994. Four alternative cases are specified which are as follows:

Base Case: For the years 1980-1984, this Case assumes the actual royalties/taxes and actual average price in the province. Prices assumed in this scenario are provided in Table 6-12. It also assumes the actual values of all exogenous variables such as the costs, interest rates, market demand prorationing, relative price of oil in

Alberta vis a vis U.S. and an average labour productivity. Table 6-13 provides the values assumed for the various write-off allowances and royalty rates. Table 6-14 provides the estimates for cost of exploration, development and production. The reserves, however, are generated within the model through the equations:

$$K_{1\,t} = A_3\, E_t^{\alpha} \quad \text{and}$$
$$K_{2\,t} = A_2\, K_{1\;t-1}^{\gamma}\; D_t^{\delta} - Q_t$$

For the period 1985-1994, we assume the new fiscal regime introduced in the Western Accord and the new provincial incentives program. The prices, again, for this period are listed in Table 6-12. The prices for oil are in line with the general industry consensus. The costs are assumed to increase at the rate of inflation. Here the implicit assumption is that although the costs increase as firms drill deeper and in more remote areas, technological improvements compensate for such increases. The reserves are generated within the model.

<u>September '81 Agreement</u>: This case assumes that the pricing and fiscal regime of 1981 continues through the 1980-1994 period. Note the prices are higher in this scenario than under the Base Case (see Table 6-12). The costs and other exogenous variables are the same as assumed in the Base Case.

TABLE 6-12

AVERAGE DOMESTIC WELLHEAD PRICE AND THE NEW OIL REFERENCE PRICE(NORP) FOR ALTERNATIVE SCENARIOS

(Cdn $)

	Base Case		September '81 Agreement		High Case	Low Case	Price of Gas
	Average Domestic Wellhead Price[1] $/b	NORP[2] $/b	Average Domestic Wellhead Price $/b	NORP $/b	Average Domestic Wellhead Price $/b	Average Domestic Wellhead Price $/b	$/'00Mcf
1980	15.55	15.55	15.55	15.55	15.55	15.55	172.17
1981	18.77	18.77	21.25	21.25	18.77	18.77	237.87
1982	24.69	41.02	24.62	28.75	24.69	24.69	251.31
1983	29.67	39.29	31.75	38.02	29.67	29.67	274.58
1984	29.67	38.74	39.75	47.70	29.67	29.67	284.44
1985	33.57	36.36	47.75	57.10	29.67	29.67	289.27
1986	36.32	36.32	55.75	66.57	39.19	33.54	294.19
1987	37.78	37.78	59.62	73.14	40.77	34.89	299.19
1988	39.25	39.25	63.79	80.32	42.76	36.25	304.27
1989	40.83	40.83	68.25	88.15	44.92	37.72	309.45
1990	42.43	42.43	73.02	96.68	47.58	39.19	314.71
1991	43.28	43.28	78.13	106.26	48.53	39.97	320.06
1992	44.14	44.14	83.59	113.69	49.50	40.77	325.50
1993	45.03	45.03	89.44	121.64	50.49	41.59	331.03
1994	45.93	45.93	95.70	130.15	51.50	42.42	336.66

1. Applicable to production and development phases.
2. Applicable to exploration phase only.
3. As NORP was abolished in 1985, and as the prices in High and Low Cases for the period 1980-1984 are similar to the Base Case, we do not have any prices for NORP under the High and Low Cases.

TABLE 6-13

AVERAGE ROYALTY RATES, WRITEOFFS AND ALLOWANCES FOR THE OIL AND GAS INDUSTRY (1980-1994)

	Average Royalty Rate for Oil	Average Royalty Rate for Gas	Exploration Expense Writeoff Rate	Development Expense Writeoff Rate	Depletion Allowance Rate	Resource Allowance Rate	PGRT Rate
1980	.3681	.40	1.0	.30	.33	.25	.00
1981	.3344	.34	1.0	.30	.33	.25	.0578
1982	.2955	.24	1.0	.30	.33	.25	.0831
1983	.2836	.22	1.0	.30	.20	.25	.0858
1984	.2882	.23	1.0	.30	.10	.25	.0876
1985	.2783	.25	1.0	.30	.00	.25	.0797
1986	.2703	.27	1.0	.30	.00	.25	.0577
1987	.2437	.25	1.0	.30	.00	.25	.0391
1988	.2390	.22	1.0	.30	.00	.25	.0254
1989	.2349	.22	1.0	.30	.00	.25	.00
1990	.2306	.22	1.0	.30	.00	.25	.00
1991	.2227	.22	1.0	.30	.00	.25	.00
1992	.2185	.22	1.0	.30	.00	.25	.00
1993	.2142	.22	1.0	.30	.00	.25	.00
1994	.2099	.22	1.0	.30	.00	.25	.00

TABLE 6-14

ACTUAL AND EFFECTIVE COSTS OF EXPLORATION, DEVELOPMENT AND OPERATING (1980-1994)
($)

	Actual Cost/ft of Exploration	Effective Cost/ft of Exploration	Actual Cost/ft of Development	Effective Cost/ft of Development	Actual Cost of Operating/m^3 of Oil and Gas	Effective Cost of Operating/m^3 of Oil and Gas
1980	244.98	189.42	161.17	60.48	11.94	5.73
1981	228.26	176.49	216.38	81.20	13.75	6.60
1982	215.50	166.62	218.39	81.95	16.44	7.89
1983	269.52	221.01	150.42	61.52	18.65	8.95
1984	280.30	239.94	156.44	68.03	19.39	9.31
1985	290.95	259.53	162.39	74.83	20.13	9.66
1986	304.33	271.46	169.86	78.27	21.05	10.10
1987	320.46	285.85	178.86	82.42	22.17	10.64
1988	338.73	302.15	189.06	87.12	23.44	11.25
1989	358.04	319.37	199.83	92.08	24.77	11.89
1990	337.73	336.94	210.82	97.15	26.14	12.55
1991	398.88	355.80	222.63	102.59	27.60	13.25
1992	421.22	375.73	235.10	108.33	29.15	15.99
1993	441.86	394.14	246.62	113.64	30.58	14.68
1994	462.18	412.26	257.96	118.87	31.98	15.35

High Case: For the years 1980-1984, High Case is the same as the Base Case. After 1984, the High Case assumes: 1. higher prices (see Table 6-12); 2. 30% increase in the level of reserves in 1985.

Low Case: Again, for the years 1980-1984, Low Case is the same as Base Case. After 1984, however, the Low Case assumes: 1. lower prices (see Table 6-12); 2. 30% decrease in the level of reserves in 1985; and 3. increase of 3% real in costs (see Table 6-14).

The estimates of exploration and development activity, the production of oil and of gas, and the cashflows of the two governments and the industry as obtained from the various scenarios, are given in Tables 6-15 through 6-21, again for the period 1980-1994. As in section 2, we divide the results into two parts - the forecasts of investment and production and forecasts of cashflows. The equations for generating the forecasts are those illustrated in footnote 3 of this chapter.

(v) Exploration, Development and Production. Table 6-15, 6-16, 6-17, 6-18 provide projections of exploratory and development activity and the production of oil and gas respectively. Over a five year period, 1980-1984, the model's projections of exploratory footage drilled diverge by 1% from the actual investment over the same period, although the trends in individual years are somewhat different. The projection for development activity differ by approximately 15% from the actual values. The projections on both oil and gas production,

TABLE 6-15

FORECASTING ANALYSIS: PROJECTED RESPONSE IN EXPLORATORY ACTIVITY
('000 foot)

	Actual Values	Base Case	September '81 Agreement	High Case	Low Case
1980	13148	12274	12274	12274	12274
1981	11362	8079	8767	8079	8079
1982	8585	6073	6825	6073	6073
1983	7188	8002	10815	8002	8002
1984	5095	10468	12740	10468	10468
Mean (1980-1984)	9076	8979	10284	8979	8979
1985	-	10425	14271	10927	10016
1986	-	11583	15672	12086	11084
1987	-	12344	16598	12922	11402
1988	-	12158	17042	12860	11261
1989	-	11973	17463	12809	11127
1990	-	11739	17816	12732	10885
1991	-	11396	18210	12294	10490
1992	-	11056	18634	11928	10178
1993	-	10741	18679	11587	9887
1994	-	10498	18842	11325	9664
Mean (1985-1994)	-	11391	17323	12147	10599

TABLE 6-16

FORECASTING ANALYSIS: PROJECTED RESPONSE IN DEVELOPMENT ACTIVITY
('000 foot)

	Actual Values	Base Case	September '81 Agreement	High Case	Low Case
1980	14392	13193	13193	13193	13193
1981	11075	14073	15235	14073	14073
1982	10928	12728	14137	12728	12728
1983	11867	16199	20225	16199	16199
1984	13619	14775	20821	14775	14775
Mean (1980-1984)	12376	14194	16722	14194	14194
1985	-	14856	21386	15537	15560
1986	-	16526	21904	16633	15474
1987	-	16690	22424	16357	14969
1988	-	16482	22907	16538	14871
1989	-	16011	22507	16499	14560
1990	-	15533	22980	16319	13975
1991	-	14945	23043	15455	13070
1992	-	14329	22882	14861	12497
1993	-	13813	22842	14362	12016
1994	-	13387	22928	13953	11615
Mean (1985-1994)	-	15257	22580	15651	13861

TABLE 6-17

FORECASTING ANALYSIS: PROJECTED RESPONSE IN PRODUCTION OF OIL
('000 m^3)

	Actual Values	Base Case	September '81	High Case Agreement	Low Case
1980	63200	66664	66664	66664	66664
1981	56978	70884	71800	70884	70884
1982	54384	73799	75224	73799	73799
1983	55317	73457	75774	73457	73457
1984	59200	75019	79968	75019	75019
Mean (1980-1984)	57816	71965	73886	71965	71965
1985	-	79287	86004	75151	76650
1986	-	81754	90693	110000	57529
1987	-	83105	92484	110000	66482
1988	-	83817	93702	100000	70395
1989	-	85291	96225	100000	74449
1990	-	87250	98886	100000	78532
1991	-	88783	100000	100000	83014
1992	-	90036	100000	100000	84893
1993	-	90971	100000	100000	86383
1994	-	91732	110000	100000	87656
Mean (1985-1994)	-	86202	96799	99515	76598

TABLE 6-18

FORECASTING ANALYSIS: PROJECTED RESPONSE IN PRODUCTION OF GAS
('000 m^3)

	Actual Values	Base Case	September '81 Agreement	High Case	Low Case
1980	77358	79077	79077	79077	79077
1981	76375	84737	87439	84737	84737
1982	78522	93574	97746	93574	93574
1983	75006	96824	100000	96824	96824
1984	68300	100000	120000	100000	100000
Mean (1980-1984)	75112	90842	96852	90842	90842
1985	-	110000	130000	110000	110000
1986	-	120000	140000	200000	68051
1987	-	120000	150000	190000	82998
1988	-	120000	150000	180000	91081
1989	-	130000	160000	170000	98885
1990	-	130000	160000	170000	110000
1991	-	130000	170000	170000	110000
1992	-	130000	170000	160000	110000
1993	-	130000	170000	160000	120000
1994	-	130000	180000	160000	120000
Mean (1985-1994)	-	125000	158000	167000	102101

however, do not correspond very closely with the actual production of oil and gas. The projected values for production of oil differ by as much as 24% and that of production of gas by 21%. Part of the difference may be explained by forced shut-in of oil in 1981 by the Government of Alberta.

For both periods, 1980-1984 and 1985-1994, the September '81 Agreement generates higher exploratory investment than the Base Case. This is largely because the prices assumed in the Agreement were much higher than what actually happened, and from our current assumptions of world prices of oil. The High Case again yields greater investment than the Base Case (an increase of 6%). The investment projections for development follow similar trends. Under September '81 Agreement, the investment is higher by 50% and in the High Case by 3%. Both for exploration and development activities, investment is the lowest under the Low Case.

The production of oil and gas also follows similar trends for alternative forecasting scenarios. However, the difference between the Base Case and September '81 Agreement is not substantial. The production of oil is 12% higher than the Base Case, and the production of gas 26% higher. This result is largely due to low price elasticities for oil. The production of oil and of gas show greater sensitivities to High and Low Case. This is largely because of high elasticities with respect to reserves of oil and of gas.

TABLE 6-19

FORECASTING ANALYSIS: PROJECTED RESPONSE IN FEDERAL REVENUE
($ '000,000)

	Actual Values	Base Case	September '81 Agreement	High Case	Low Case
1980	670	920	920	920	920
1981	2500	2700	3000	2700	2700
1982	3800	4200	4700	4200	4200
1983	4100	4600	5500	4600	4600
1984	5100	4600	7300	4600	4600
Mean (1980-1984)	3234	3404	4284	3404	3404
1985	-	5500	9300	5700	5300
1986	-	5900	11000	11000	2800
1987	-	6000	13000	10000	3400
1988	-	6200	14000	9400	4000
1989	-	6200	16000	8900	4200
1990	-	6500	18000	9100	4600
1991	-	6700	20000	9100	4900
1992	-	6900	21000	9100	5100
1993	-	7000	23000	9200	5200
1994	-	7200	24000	9200	5400
Mean (1985-1994)	-	6410	16930	9070	4490

TABLE 6-20

FORECASTING ANALYSIS: PROJECTED RESPONSE IN PROVINCIAL REVENUE
($ '000,000)

	Actual Values	Base Case	September '81 Agreement	High Case	Low Case
1980	3900	4100	4100	4100	4100
1981	4500	5400	5900	5400	5400
1982	4600	6000	6800	6000	6000
1983	4900	6600	8300	6600	6600
1984	7600	7000	11000	7000	7000
Mean (1980-1984)	5100	5820	7220	5820	5820
1985	–	8500	13429	8755	8214
1986	–	9700	16890	16790	5730
1987	–	9600	18960	14690	6250
1988	–	9600	20000	13640	6770
1989	–	10000	22200	13640	7390
1990	–	10000	24200	13650	7910
1991	–	11000	26300	13650	8230
1992	–	11000	27400	13650	8530
1993	–	11000	29500	13650	8740
1994	–	11000	31600	13650	8940
Mean (1985-1994)	–	10140	23048	13577	7670

TABLE 6-21

FORECASTING ANALYSIS: PROJECTED RESPONSE IN INDUSTRY REVENUE
($ '000,000)

	Actual Values	Base Case	September '81 Agreement	High Case	Low Case
1980	4600	4500	4500	4500	4500
1981	3500	4300	4800	4300	4300
1982	3600	5200	6000	5200	5200
1983	4600	6700	8600	6700	6700
1984	7400	7100	11000	7100	7100
Mean (1980-1984)	4740	5560	6980	5560	5560
1985	-	7900	13000	8250	7585
1986	-	11000	15000	15210	7170
1987	-	12000	17000	16310	8750
1988	-	13000	19000	17360	9730
1989	-	14000	21000	18360	10710
1990	-	15000	24000	19350	11690
1991	-	16000	27000	19350	12670
1992	-	16000	30000	19350	12670
1993	-	16000	32000	20350	12660
1994	-	17000	35000	20350	13660
Mean (1985-1994)		13790	23300	17424	10730

TABLE 6-22

FORECAST REVENUE SHARING IN THE OIL AND GAS INDUSTRY
(1980-1984)

	Actual	Base Case	September '81 Agreement	High Case	Low Case
	%	%	%	%	%
FEDERAL	25	23	23	23	23
PROVINCIAL	39	39	39	39	39
INDUSTRY	36	38	38	38	38

(1985-1994)

	Actual	Base Case	September '81 Agreement	High Case	Low Case
FEDERAL	--	21	65	22	20
PROVINCIAL	--	34	36	34	33
INDUSTRY	--	45	37	43	47

(vi) Cashflows: The Cashflows of the two levels of government and the industry are provided in Tables 6-19 through 6-21. The tables suggest that under the September '81 Agreement, the share of the federal government is much larger than under the Base Case (increase of 164 percentage points). The provincial share also increases considerably but less than the federal share (127 percentage points). The industry gains the least under this Agreement (69 percentage points). The impact of the High Case and the Low Case is fairly uniform over the three sharing parties.

Table 6-22 provides the revenue sharing under the alternative cases. The industry share increases over 1985-1994 period to 45%. The federal share decreases by 2% and the provincial share by 5%. Over the period 1985-1994, the Base Case yields the highest industry share. In contributing to an increased industry share, the provincial government takes a larger cut. Revenue sharing under the High and Low Case is similar to the Base Case.

Again, the results indicate that between 1980-1984, the model approximates the revenue sharing quite well. The actual federal, provincial and the industry shares of 25, 39, and 36% respectively can be compared with the projected share of 23, 39, and 38% respectively.

3. The Model: Forecasting Accuracy.

Tables 6-4 to 6-10 in Section 1, and Tables 6-15 and 6-21 in Section 2 indicate how the model projections compare with the observed phenomenon. These comparisons are summarized in Figures 6-1 to 6-4. It can be seen that the projections of the exploratory and development activity over the period 1971-1979 and 1980-1984 on average, track the observed values quite well. However, in 1984, the model over-predicts the exploratory activity by as much as 100%. Although the model projects the production of oil and gas quite accurately for the period 1971-1979, it over-estimates the production between 1980-1984. Comparing the mean of actual and projected (Base Case) values, it can be seen that the model over-predicts the production of oil by 24% and of gas by 21%. The divergence between the actual and projected values increases with years.

The wide variation between the actual and predicted values may be explained by the following: Q_{oil} and Q_{gas} are highly sensitive to changes in K_2, the level of reserves of oil and gas. Q_{oil} has an elasticity of 1.09 and Q_{gas} an elasticity of 1.65. The values of K_2 used to generate the projected values of Q_{oil} and Q_{gas} are generated through the constraint which defines the changes in $K_2(\dot{K}_2)^4$. The projected values of K_2 are over-estimated by approximately 5% between the years 1980-1984 with the divergence increasing with years. In 1980, the difference between the actual and projected value of K_2 is 2% and in 1984, it is 7%. A 7% variation in the projected value of K_2 from its actual value translates into a roughly 7% divergence in Q_{oil} and 11% divergence in Q_{gas}. Further, a negative coefficient for the price of gas in both the Q_{oil} and Q_{gas} equations may also have contributed to over-predictions of Q_{oil} and Q_{gas}.

Figures 6-1 and 6-2 indicate that investment in exploration and development activity will increase significantly. These projections compare well with the general industry consensus. However, for lack of appropriate studies in this area, no specific comparisons with the forecasts generated in this section, for years 1985-1994 can be provided. The deregulation of the petroleum industry, the abolishment of certain taxes, and the reduction of royalties all contribute to a brighter outlook and positive producer expectations in the industry. The specific role of producer expectations in driving the energy investment is emphasized in a study by the Economic Council of Canada (Scarfe and Rilkoff, December, 1984). Expectations of future prices of oil and gas, the costs of finding oil and gas, the cost of financing the investment, all play an important part in determining the activity levels. More importantly, our results indicate that the policy parameters have an even larger impact as they not only affect the net price or net cost to the investor but effect general expectations. The drop in activity following the 1980 NEP, was not only due to a drop in net price due to additional taxes, such as the PGRT, but also because the program created an environment of uncertainty and distrust in the government. Note the risk taking

FIGURE 6-1
ACTUAL AND PROJECTED EXPLORATORY ACTIVITY
(1971 - 1994)

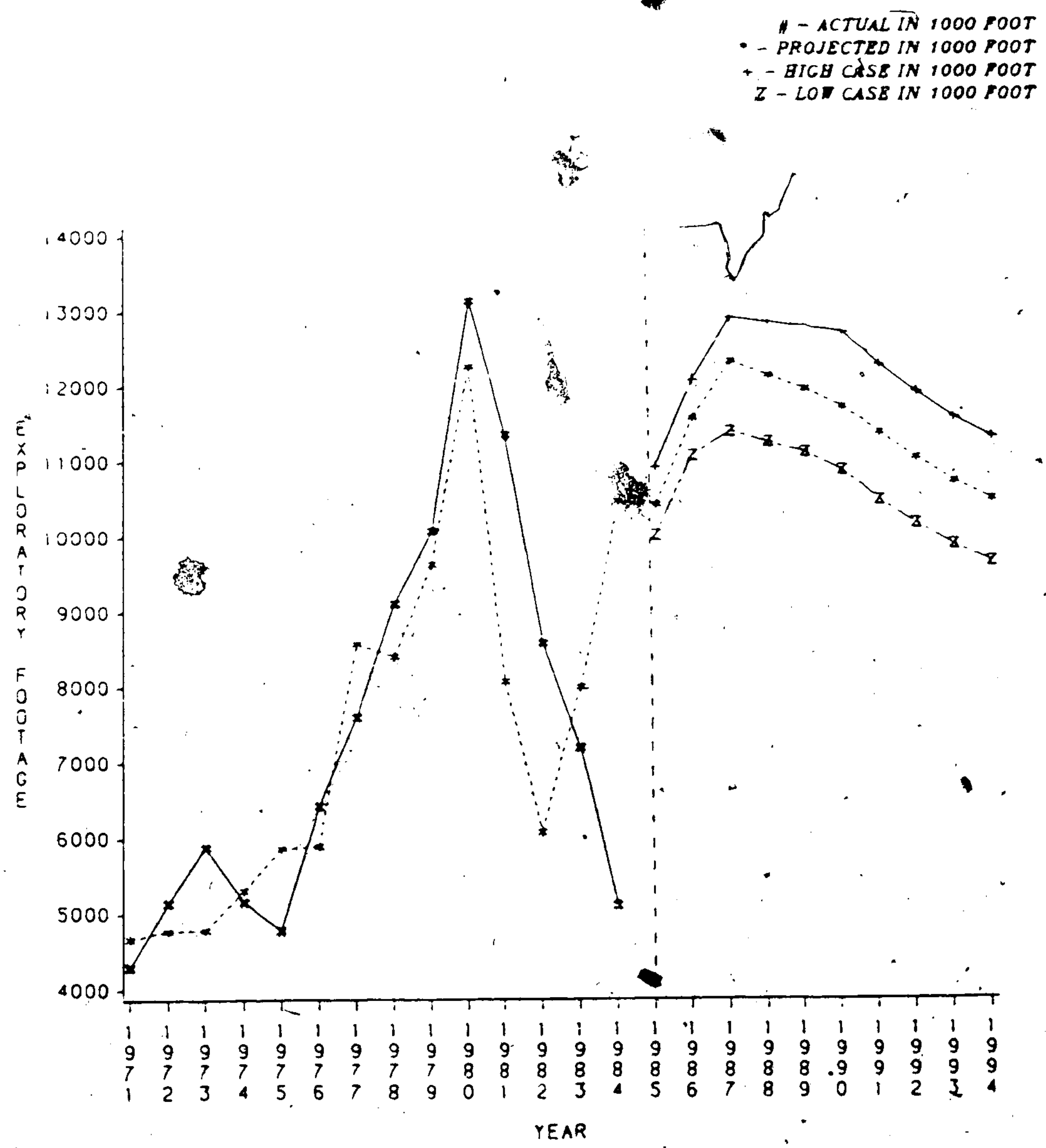


FIGURE 6-2

ACTUAL AND PROJECTED DEVELOPMENT ACTIVITY

(1971 - 1994)

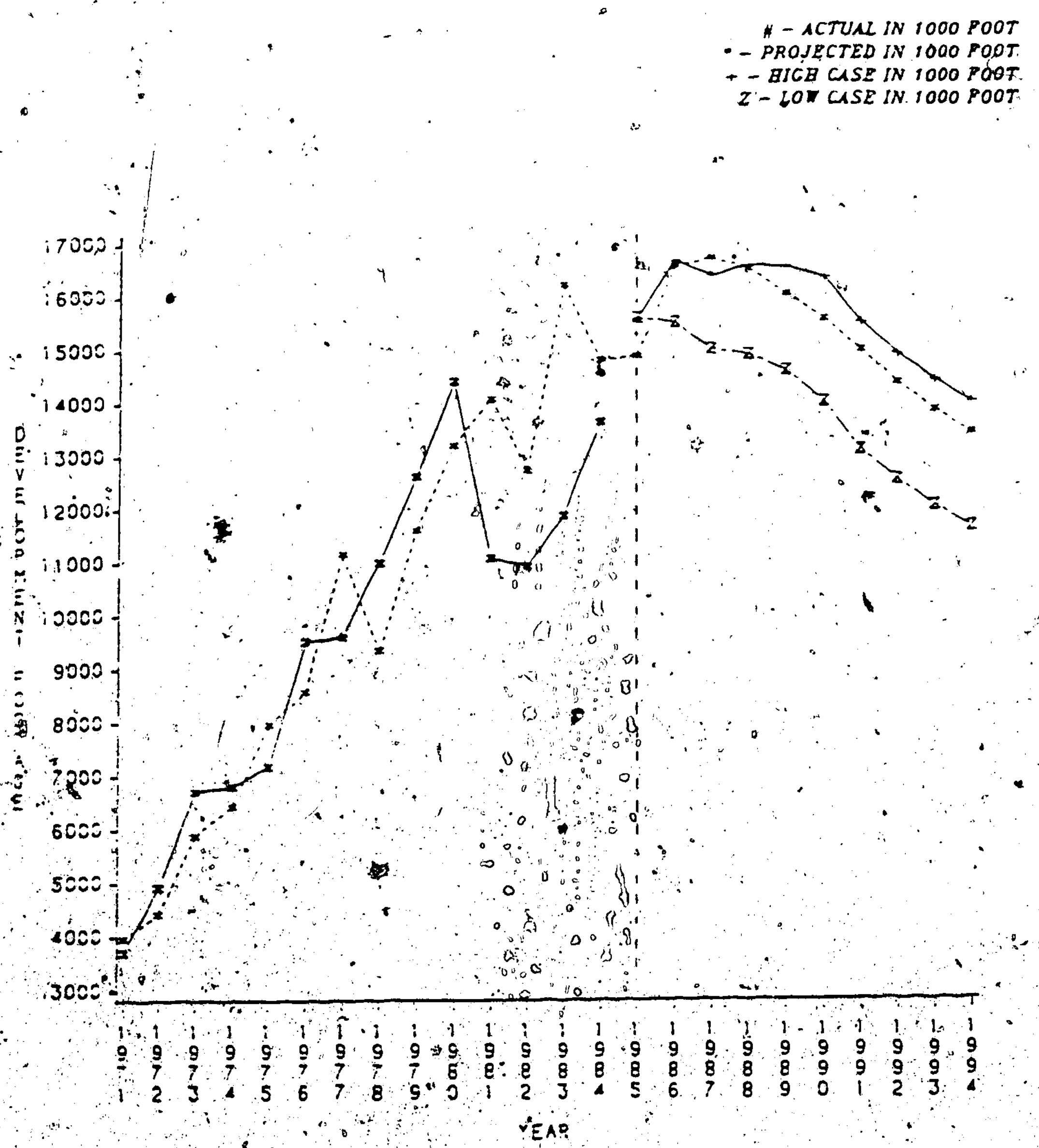


FIGURE 6-3
ACTUAL AND PROJECTED PRODUCTION OF OIL
(1971 – 1994)

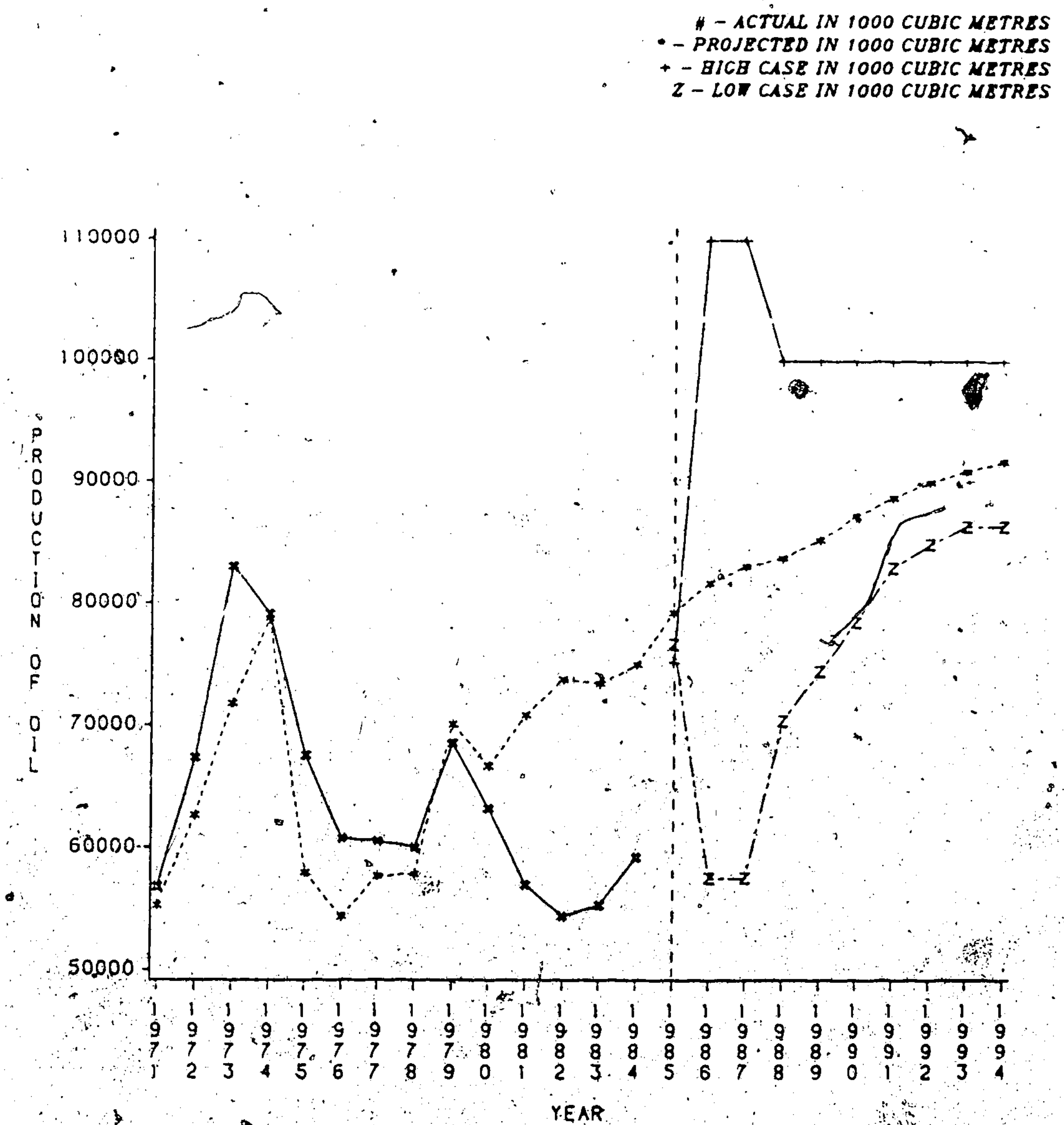


FIGURE 6-4
ACTUAL AND PROJECTED PRODUCTION OF GAS
(1971 - 1994)

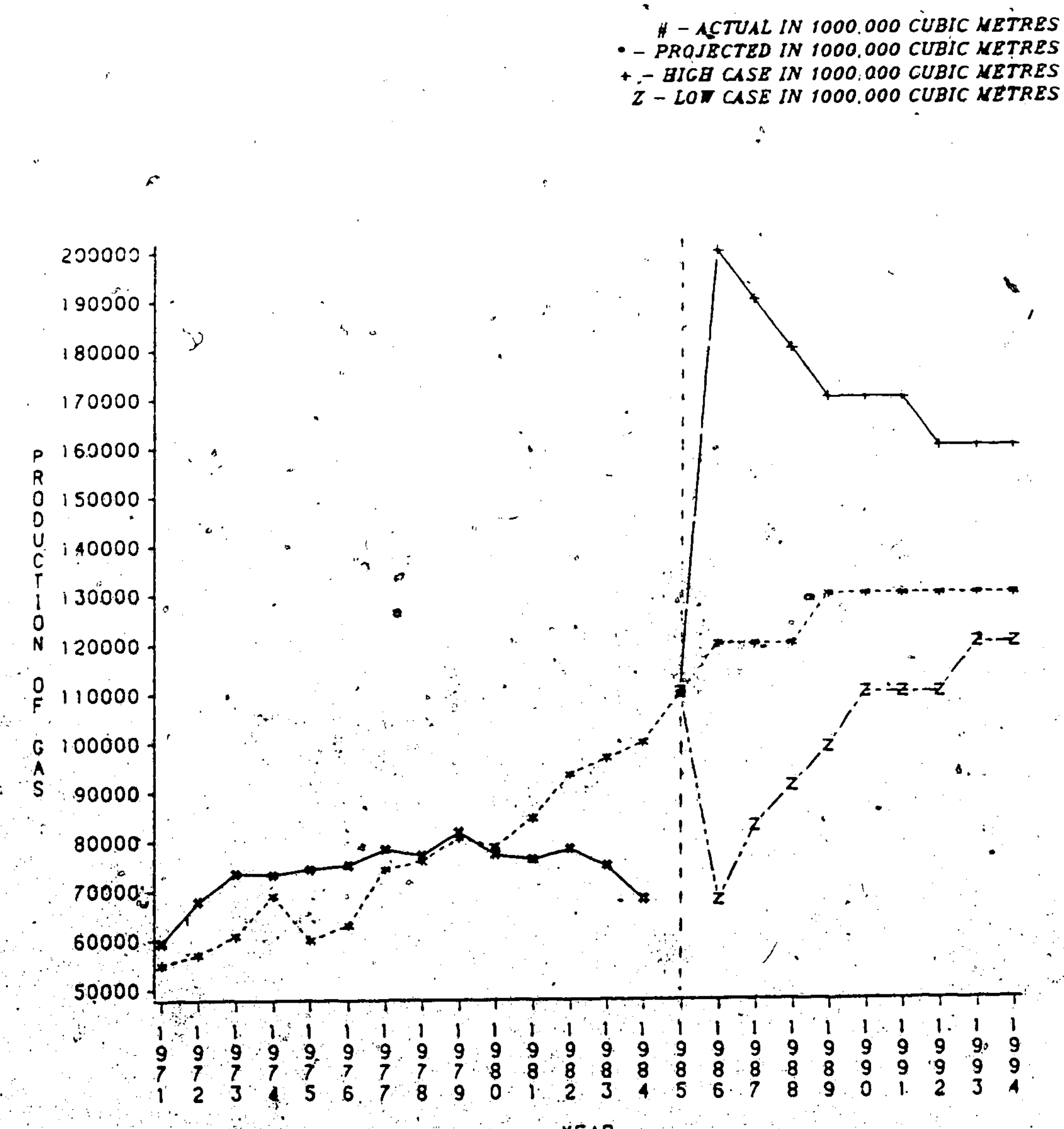
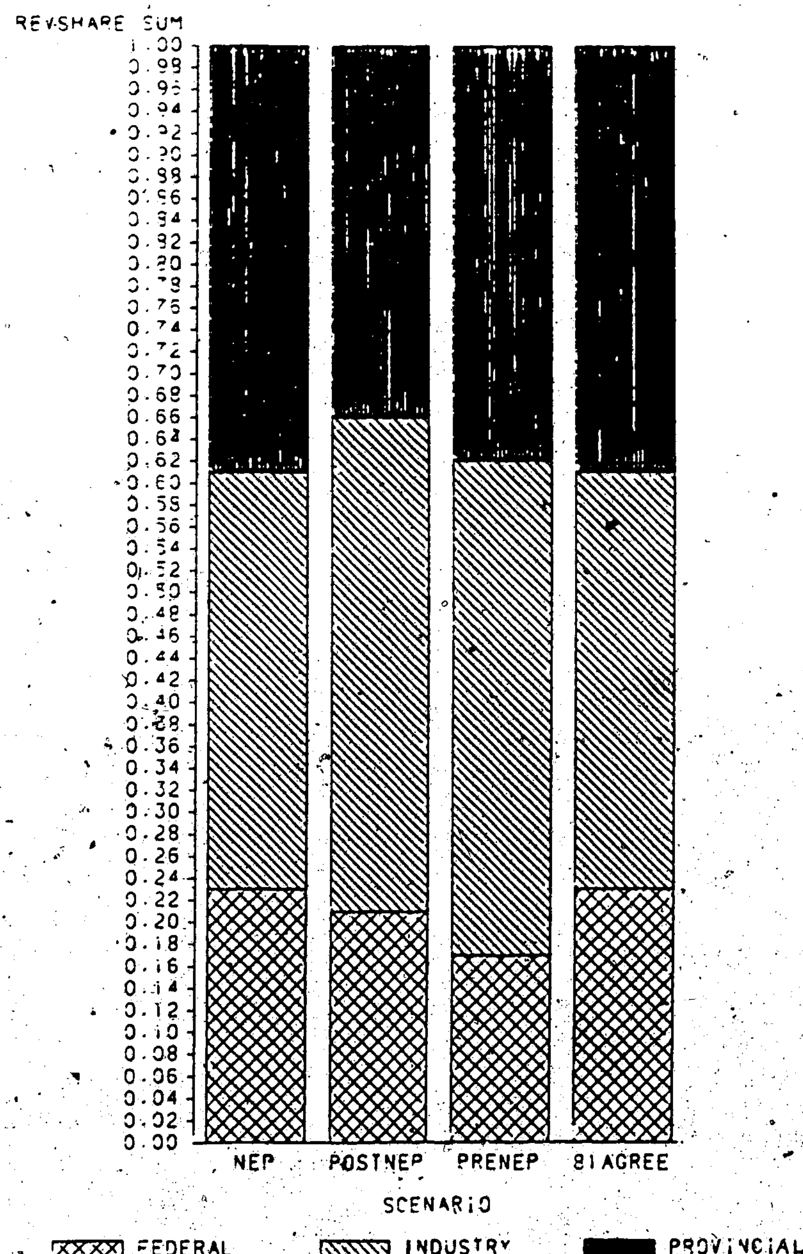


FIGURE 6-5

REVENUE SHARING IN THE OIL AND GAS INDUSTRY

(VARIOUS FISCAL SCENARIOS)



behavior declines significantly under an environment of uncertainty.

Table 6-22 indicates that following the revisions made under the Western Accord, the industry will restore its pre-NEP share in the total revenue generated in the petroleum sector. Figure 6-5 indicates the revenue sharing between the three parties in three significantly different periods: pre-NEP, NEP and post-NEP. The graph also indicates the revenue sharing under the September '81 Agreement. Note the federal share is the highest under the September '81 Agreement and the NEP period. The provincial share in the post-NEP period does not go back to the pre-NEP share. This is largely because of the reduced royalty rates under the new oil and gas incentive program.

Footnotes:

1. Note that taxes (various Canadian federal, provincial and municipal taxes, including mineral taxes but excluding income taxes) as a % of the price of both oil and gas are assumed to be insignificant and are therefore omitted. For example, the tax per barrel of oil ranged between \$.01 in 1971 to \$.11 in 1979. When converted to a ratio of the price of oil, it ranged from .0036 in 1971 to .008 in 1979. The price is not calculated before corporate income tax basically because we later deduct this tax from the cash flow of the industry. Including them here would mean double counting.

2. Statistical problems, for example collinearity, might be another cause of such a result. A low degree of reliability of the data on costs might be yet another reason. However, we feel that this might not be the case. C_D is significant and is of the expected sign when regressed in equation 4-52 (development). Also C_E appears with expected sign in equation 4-51, and C_N with the expected sign in equations 4-53 and 4-36.

3. The exact regression results are given as follows:

$$\text{Log } E = \underset{(30.85)}{14.96} + \underset{(0.53)}{.00477} \log C_E + \underset{(5.20)}{.755} [\log \mu + \log (a + \mu - i)]$$

$$- \underset{(-.994)}{.174} (i) + \underset{(1.61)}{.534} \log P_{oil} + \underset{(1.44)}{.246} \log P_{gas}$$

$$+ \underset{(3.79)}{.669} \log RP_{oil\ U.S.}$$

$R^2 = .87$ $\bar{R}^2 = .83$ D.W = 1.94 df = 12

$$\text{Log } D = \underset{(20.99)}{17.41} - \underset{(-5.28)}{.412} [\log C_D - (\log \mu + \log (a + \mu - 1))]$$

$$- \underset{(-2.84)}{.208} \log K_1 + \underset{(1.55)}{.613} \log P_{oil} + \underset{(2.79)}{.536} \log P_{gas}$$

$$- \underset{(-3.62)}{.486} \log MDP - \underset{(-1.63)}{.333} \log RP_{oil\ U.S.}$$

$R^2 = .88$ $\bar{R}^2 = .84$ D.W. = 1.92 df = 12

$$\log Q_{oil} = \underset{(6.21)}{4.16} - \underset{(-1.51)}{.158} [\log C_N + \log(a + \mu - i) - \log(a - i)]$$

$$+ \underset{(20.65)}{1.08} \log K_2 + \underset{(.586)}{.0857} \log P_{oil} - \underset{(-5.57)}{.412} \log P_{gas}$$

$$- \underset{(-10.89)}{.517} \log MDP$$

$R^2 = .99$ $\bar{R}^2 = .98$ D.W. = 2.09 df = 13

$$\log Q_{gas} = \underset{(-3.53)}{-4.56} + \underset{(-.572)}{1.643} [\log C_N + \log(a + \mu - i) - \log(a - i)]$$

$$+ \underset{(16.05)}{1.64} \log K_2 + \underset{(.643)}{.229} \log P_{oil} - \underset{(-1.83)}{.329} \log P_{gas}$$

$R^2 = .95$ $\bar{R}^2 = .94$ D.W. = 1.24 df = 13

3. $$\log K_{2t} = \underset{(2.73)}{4.42} + \underset{(3.30)}{.53} \log K_{2t-1} + \underset{(1.79)}{.211} \log K_{1t}$$

$$+ \underset{(3.44)}{.093} \log D_t - \underset{(-1.35)}{.092} \log Q_{oilt}$$

$R^2 = .99$ $\bar{R}^2 = .98$ D.W. = 2.49 df = 14

CHAPTER VII: CONCLUSIONS

The discussion to follow summarizes the model formulated in the present study and highlights some of the results obtained from estimating the model. It also discusses certain policy implications indicated by the empirical results. The discussion is divided into three sections: Section 1 presents a summary of the model and the empirical results; Section 2 highlights the policy implications; and finally Section 3 outlines the limitations of the study.

1. Summary.

The present study has formulated a micro, partial equilibrium model of the oil and gas industry in Western Canada wherein the ultimate production of oil and gas is analyzed within three activity phases, viz. exploration, development and final extraction. Exploration and development are treated as investment decisions and extraction as a production decision. The firm is assumed to maximize the present value of a stream of future anticipated profits - subject to a CET production function and the two capital flow constraints, viz. change in the level of probable reserves and change in the level of proved reserves. The process of maximization yields four estimating equations. The first two explain the extent of exploration and development activity respectively in the oil and gas industry; the last two explain the level of production of oil and of gas. The determining variables include the cost of various input activities; the prices of oil and gas; the level of reserves both probable and proved; royalty rates, the income tax rates, allowances and writeoffs; the extent of market demand prorationing; and the price of oil in Alberta relative to that in the U.S.A. The latter two variables are imposed on the model. The model can then be used to analyze in detail the effects on activity decisions of specified changes in particular exogenous variables or public policy parameters such as prices, market outlets, royalties, taxes and related incentives. The supply model is not directly linked to a demand model, but demand influences are reflected through the inclusion of a market demand prorationing variable in the supply equations. Note that the variable is a ratio of capacity (supply) to production (demand).

An alternative partial exploration sub - model is also formulated which seeks to explain exploration activity more in terms of the unique institutional structure of the oil and gas industry. Three equations are specified with interdependence between each of the equations. The first seeks to explain the level of exploration activity, the second the expected profitability in the oil and gas industry, and the last purports to explain the drilling success ratio. Among the independent variables considered are the price of oil in Alberta relative to that in the U.S.A., returns on employed capital in alternative and generally similar industries, the level of retained earnings generated in the oil and gas industry, the number of acres acquired under existing drilling agreements (leases and licenses), expected netback prices of both oil and gas, the expected costs of exploration and development, and the estimated level of undiscovered reserves. The interdependence between the three dependent variables is explicit in the specification. The first variable is explained among other variables, by expected profitability. Expected profitability in the second equation is explained partly by success ratio which is then explained by the level of undiscovered reserves appearing in the third equation.

Both models are estimated with aggregated annual data for Alberta as a whole from 1960 to 1979, and with disaggregated annual data using a sample of the fifteen major oil fields over the period 1965-1979. In the case of disaggregated data, the model is estimated first for each of the fifteen fields over the fifteen year period, second for each of four zones formed by sub-grouping these fifteen fields over the same time period, and third by grouping all the fields over the same period. Both the aggregated and disaggregated analyses help us to identify the geological features which distinguish one field from another or one zone from another. The results presented in Chapter IV indicate that the model is most successful in explaining the exploration, development and production activities for the province as a whole without regard to particular fields or zones within the province. The model's performance for disaggregated data is relatively less promising, but the model succeeds in distinguishing between the behavioral relationships underlying the operations of a mature field as opposed to a newer field (or zones) over the period studied. It also illustrates how the same government policies or regulatory mechanisms could impact differently on the activity decisions in the various fields or zones.

Among the variables considered in the exploratory equations, activity is found to be the most sensitive to changes in the relative price of oil in Alberta vis-a-vis the U.S., and the domestic price of oil. These two variables affect the exploratory activity in both models: the first enters directly in both models; and the second enters directly in the first and through expected profitability in the second. The per-foot cost of exploration as a determining variable is insignificant in both the models. A non-finanancial variable, the number of acres held under drilling agreements, is significant in explaining exploration in the second model. The empirical results indicate that exploratory activity is influenced by both monetary variables (prices, costs, relative returns in similar industries elsewhere and in alternative industries) and non-monetary variables (claims on the resource). Of course, in some instances the impact of the financial and non-financial variables may not be independent. For example, the amount of land held under lease itself may be influenced by the general financial outlook.

The models consider cost per foot drilled as an explanatory variable as opposed to cost per unit of oil and gas found. The elasticity of exploration with respect to footage cost is not uniformly significant. It is thought that for the following reasons, the cost per unit of reserves found may be a more significant explanatory variable than cost per foot drilled. An increase in cost per foot drilled with marginal or no increases in cost per unit of reserves discovered may not exert a negative effect on exploratory investment. On the other hand, if the cost per foot drilled were relatively stable but the cost per unit of reserves found increased, a negative impact on exploration might take place. This phenomenon may be evident from our results. For zones, we find that exploration cost per foot, C_E, exerts a significantly negative influence in the Plains and Central regions. Note that these regions have been subject to heavy drilling in the past and therefore the general expectation would be that a relatively low level of reserves would be found by further drilling. Thus the percentage increase in the reserves in these regions may be lower than the percentage increase in cost of exploration, resulting in increased cost per unit of reserves found. This may lead to a negative impact on exploratory activity. Interestingly, C_E exerts a positive and significant impact in the Foothills zone and a negative but insignificant influence in the Northern zone. These two regions are yet to be fully explored. The reserves discovered per foot drilled may still be increasing in these regions. The percentage increase in reserves may be higher than increases in cost of exploration, resulting in a decrease of the cost per unit of reserves. Thus, in these newer regions, although the cost per foot drilled may be increasing, the exploration activity may also be increasing, largely because of decreasing cost per unit of reserves. Also, because the costs are not normalized for depth, in newer regions where costs increase exponentially with depth, and wherein the average depth of a well is high, a positive impact through supply effects may be evident. In general then, the varied response of exploration to cost per foot drilled for different zones and fields could be explained with reference to the above arguments.

Development activity over all data sets appears to be uniformly sensitive to the price of oil, the price of gas, the market constraints and the per foot cost of development drilling. The relative price of oil in Alberta vis-a-vis the U.S.A. has a different effect on development activity in different zones. In relatively newer fields (or zones) it has a positive impact, but in older fields (or zones) the impact is negative. Thus in older fields which are more fully depleted there may be a movement in investment funds from such fields to newer ones as a result of more attractive prices for Canadian oil. Thus even if the Alberta price of oil vis-a-vis the U.S.A. increased, this may not generate increased development activity in relatively mature fields.

Market demand prorationing again has a different effect on development activity in different fields. In older areas where the scope for further drilling is limited by the well-spacing regulations, and where new discoveries are hard to find, more severe market demand prorationing has a negative impact. But in regions where newer drilling can be undertaken and there are newer discoveries leading to further development drilling, more restrictive market demand prorationing has a positive impact. Thus in these regions the operators can acquire a greater share of the given total market by drilling more wells and discovering new pools.

Production of both oil and gas across almost all data sets is found to be significantly sensitive to market availability as reflected in market prorationing quotas, and to the level of proved reserves. The empirical elasticities of production with respect to various independent variables suggest that in the production phase operators are keener to produce partly to recover their exploratory and development cost and partly due to the inherent nature of the 'rule of capture'. The structure of the oil and gas industry resembles that of the common property resource. The resource belongs to whomever drills and extracts the resource. Thus operators are likely to produce their market allowable share, irrespective of the level of prices or costs. But the amount they can actually produce is restricted by the market outlets. The results also indicate a further interesting feature of the oil and gas industry. Oil and gas production appear to follow similar trends. Thus, although technically the two markets are independent, they have been subject to similar external forces in much of the period under observation. Therefore, not only the associated gas but also the non-associated gas is positively related to the production of oil.

The alternative model suggests that the success ratio in exploration for the province as a whole is still increasing, though at a reduced rate; therefore we are still on the rising part of the discovery curve. Since our success ratio is defined as a ratio of the total number of successful exploratory wells (oil and or gas) to the total number of exploratory wells drilled, the increase in success ratio could have been a result of increases in the success for gas-only discoveries.

2. Policy Implications

Certain policy implications derived from the study can now be summarized as follows:

(1). The high elasticities of exploration and development activity with respect to net prices of both oil and gas stress the effectiveness of royalty rates and of wellhead prices insofar as these can be said to be influenced by public policy. Of all the alternative scenarios considered in the sensitivity runs described in Chapter VI, exploration and development are the most sensitive to changes in net prices. Two types of changes affecting the net prices are considered: 1. the royalty rate on both oil and gas is first reduced by 25% and then by 50% of the existing royalties; 2. the price of oil is changed to the world prices which implies that the Canadian prices are lower for years 1971-1973 and higher for years 1974-1979, in comparison with the existing prices. The highest level of activity is achieved under the latter scenario: exploratory activity increases by 31% and development activity by 35%. Under the first scenario, with reductions of 50% in the royalty rates of oil and gas, exploration increases by 19% and development by 27%.

Although investment is highly sensitive to changes in net price, production is marginally affected by (1) and (2) above. Low elasticities with respect to price of oil and a negative elasticity with respect to price of gas, both contribute to a negligible response of Q_{oil} and Q_{gas} to changes in net prices.

Both the magnitude of revenues and the revenue sharing is affected by changes in net price. With 50% reduction in royalties, the federal and provincial revenues decrease by 10% and 41% respectively. The industry gains as much as 50% in revenues. A part of the revenues lost by the provincial government can be regained through higher bonus bids on the various leases and licenses leased out by the government. This will occur through increases in expected profitability, resulting from increases in net price[1]. (The reader is referred to the alternative model in Chapter IV. Note bonus bids are taken to be a proxy for expected profitability.) With the price of oil equal to the world price, the revenues for all three parties increase: the federal revenue increases by 92%, provincial by 60% and the industry share by 42%. The above indicates that the effect of changes in netback price is on exploration and development investment outlays, and not on production apart from a re-distribution of revenues between provincial government and the industry.

(2). Due to the low cost elasticities, the effect of changes in federal allowances and write-off rates, through their influence on effective cost, is not as pronounced as that of changes in royalties or prices (point 1 above). Absence of depletion allowance does not trigger significant changes in investment or production. Exploration, Q_{oil} and Q_{gas} change by less than 1%. Development activity changes by 4%. In revenues, and revenue sharing, there is a redistribution of income from the industry to the federal government. The federal revenue increases by 15% and the industry revenue decreases by 13%.

Thus, due to the low elasticities, the effect of phasing-out the depletion allowance under the NEP would likely have marginal effects on investment levels directly; but could affect the revenue structure and depress the total revenues left with the oil and gas industry, and thus may decrease the investment eventually.

(3). While investment activity in exploration and development is influenced most by prices, the production of oil and gas is influenced most by physical constraints - the level of proved reserves and restricted market availability. In our sensitivity analysis, a reduction of royalties changes production marginally but the absence of market constraints increases the production of oil by 15% and that of gas by 19%.

(4). The results directly or indirectly suggest that government programs such as market demand prorationing, well-spacing and the drilling and geophysical incentive program have influenced investment in the industry. A significant (observed) effect of market demand prorationing, which primarily has to do with the inadequacy of markets in relation to capacity, has important implications for programs such as increased export markets. Note that inadequacy of markets would have a uniformly negative production impact in all zones. But the way in which the prorationing system is structured to allocate production to restricted markets may generate differential effects on zones. In Alberta, prior to 1964 the prorationing program directly encouraged drilling as the market allowable was per well based. Since the amount of drilling is constrained by well-spacing regulations, the program may have had a discriminating effect on various zones. In newer zones, where the cumulative number of wells drilled is small, it may have had more of an effect than in mature areas where small number of new wells could be drilled, given the well-spacing regulations. After 1964, the allocation was made on per pool basis and therefore encouraged the discovery of new pools. Following the discovery, the program may indirectly encourage drilling of development wells. Again, most pools were discovered in newer areas and hence MDP may have exerted a positive impact on development drilling in those areas. That the effect of MDP differs between the regions indicates that not only do government policies influence activity in the oil and gas industry, but also they may have differential effects depending on geology and historical experience.

The geophysical and exploratory drilling incentive program introduced in 1973-1975 aimed primarily at curtailing the movement of investment funds in the oil and gas industry from Alberta to elsewhere. After the introduction of the program, exploratory activity in the province increased 71% by 1979. But the same period also saw an increase in exploratory costs per foot drilled[2]. Through this program, the costs were subsidized by as much as $20 per foot drilled on average. Table 7-1 provides exploratory cost per foot drilled, with and without the incentive payments.

However, the effect on costs and the efeect of the program in increasing the exploratory activity may not be uniform across the province. In newer areas where a larger number of wells qualify for exploratory incentives, the program may have had a significant effect with relatively little effect in older areas. Our results indicate that despite increasing costs, activity increased in these newer areas and the exploratory incentives program may have been instrumental in bringing about this differentiated effect.

TABLE 7-1

EXPLORATORY COST PER FOOT DRILLED: PROVINCIAL AVERAGE

(excluding land costs)

	Without incentive payments	With incentive payments
1970	37.05	37.05
1971	34.03	34.03
1972	33.71	33.71
1973	34.39	32.23
1974	50.22	46.96
1975	51.97	45.19
1976	62.90	53.72
1977	81.43	70.71
1978	109.23	98.72
1979	136.65	126.99
1980	189.32	177.96
1981	215.98	195.34

Source: CPA, Annual Statistics, 1981 Section IV, Tables 3A and 3B; Alberta's Reserves, 1981 ERCB 80-18, Table A-1.

3. Limitations

The present study suffers from two basic limitations. First, the model developed in this study is a partial equilibrium model. It is not embedded in a macro model and therefore cannot take into account the interactions between the various industries. It is incapable, therefore, of taking fully into account factors such as relative returns in other industries or in the same industry elsewhere in Canada or abroad. It therefore cannot deal adequately with the movement of funds from the Alberta oil and gas industry to other industries within Alberta, or to the same or other industries elsewhere. We have incorporated the relative price of oil in Alberta vis-a-vis the U.S.A. as an explanatory variable to take into account the movement in investment funds which may take place from Alberta to the U.S.A. Because this variable is based on wellhead price rather than a netback price, (price net of royalties and taxes), it may not reflect changes in royalties in either countries. Also, because it is a supply model, it excludes the demand related determinants of production. Thus, though the model forecasts investment and production levels as well as cash flows under various scenarios, the above shortcomings may indicate that a comparison of general tendencies is more meaningful than one involving exact magnitudes.

Second, because the disaggregated data were obtained from unpublished sources, it is difficult to check their reliability. For example, to obtain information on the cost data for each field, questionaires were sent to 30 major oil companies. But a reasonable response was received from only 7 of them. Thus there was a lack of sufficient data on some of the variables used in the model. This may have been a cause of significant variations in the magnitude and sign of coefficients for obtained for various fields and zones. However, the model needs to be re-thought in case of smaller regions - such as the field or a zone.

Third, there is a lack of a marketability variable for gas. Since the lack of markets is one of the key factors controlling the production levels and the development of gas reservoirs which have already been discovered, this is a serious shortcoming of the model.

Whatever may be these limitations the remaining pages of the study set out certain supplementary information covering such things as the calculations and the source of the data used in the study (Appendix A); detailed information on the derivation of the model with symbols and technical definitions used on some of the variables dealt within this study (Appendix B); and some exhibits including a sample of the questionnaire (Appendix C).

Footnotes:

1. The trends in the last decade suggest that the expected profitability (as indicated by land payments per acre) is sensitive to, among other variables, changes in oil prices. Land bonuses per acre which were on a decline through the early '70s increased after 1973. The following table gives the historical trends in expected

profitability as indicated by land bonuses per acre and the wellhead prices of oil.

TABLE 7-2

HISTORICAL TRENDS IN LAND BONUSES/ACRE AND WELLHEAD PRICE OF OIL

	Land Bonuses Per Acre(nominal $)	Wellhead Price of oil/bbl
1965	16.45	2.41
1966	14.13	2.39
1967	11.20	2.38
1968	13.09	2.40
1969	15.36	2.42
1970	5.55	2.69
1971	3.92	2.75
1972	4.73	2.77
1973	9.39	3.41
1974	18.93	5.72
1975	21.18	7.18
1976	47.35	8.38
1977	169.98	10.75
1978	152.98	12.75
1979	193.00	13.75

Source: CPA Annual Statistics, Section1, Table 1
Section IV, Table1, Section IV, Table 1.

2. There seems to have been an unusually severe increase in costs in 1974. The Canadian non-residential construction costs increased in 1974 by as much as 21%. In previous years (much of the '60s and the early '70s), the annual increase in costs was under 10%. In United States, drilling costs in the oil and gas industry increased by 32% in 1974. In the '60s, drilling cost in the U.S oil and gas industry increased at an average of 3% and in the early '70s by less than 11% per annum. The cost increases in the years after 1974 have been much greater than in the '60s. The following table illustrates the changes in the Alberta oil and gas drilling costs, U.S. onshore drilling costs, and the Canadian non-residential material costs.

TABLE 7-3

ANNUAL CHANGES IN VARIOUS COST INDICES

	Alberta Oil and Gas exploratory drilling cost	U.S. Oil and gas onshore exploratory drilling cost	Canadian non-residential construction material cost
1970	-.07	.10	.03
1971	-.08	.02	.02
1972	-.009	.086	.06
1973	.02	.11	.10
1974	.46	.32	.21
1975	.034	.25	.07
1976	.20	.06	.06
1977	.30	.14	.05
1978	.33	.21	.08
1979	.25	.19	.16
1980	.38	.15	.10
1981	.14	.24	.10

Source: Calculated from CPA, Annual Statistics, 1981 Section 3, Table 3a and 3b; American Petroleum Association, Petroleum Handbook, 1981, Tables 10 and 10b.

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APPENDIX A: THE DATA

The following Appendix is divided into two sections. Section 1 details the data used for the regression analysis in Chapter V. Section 2 discusses the data used for generating Chapter VI forecasts of the endogenous variables.

1. Historical Data

The data on all variables - endogenous and exogenous - pertain to the province of Alberta and to fifteen major oil fields within that province. 'Major' oil fields are defined on the basis of level of annual production, and the size criterion employed is that used by the AERCB. A field is said to be a major oil field if its annual production is more than 222.6 10^3 m^3. A list of major oil fields was obtained from AERCB's Alberta Oil and Gas Industry - Annual Statistics , 1979. The fields were then classified as belonging to one of the four drilling incentive zones. The third step was to select the four largest oil fields in each zone.

A time period of 20 years from 1960 to 1979 was selected for the province of Alberta, and a time frame of fifteen years from 1965 to

1979 was selected for individual fields. As explained in Chapter V, Section 1, the limited time frame for the individual fields was chosen because of two factors: firstly the difficulty of obtaining data on micro units, and secondly the fact that of the fifteen fields selected for the present study, five were discovered after 1965 and five, though discovered prior to 1965, did not experience much activity until after that date. The observations on each of the variables, both for the province of Alberta and the fifteen fields, are annual.

While the data for the province of Alberta were obtained mostly from published sources, the data for the individual fields were obtained from unpublished sources. Part was provided by organizations such as the AERCB and the Geological Survey of Canada, and part was calculated on the basis of certain reasonable assumptions. Information on each of the variables used in the present study is given in the following sections:

Exploration and Development Footage. All of the data on physical units for the fifteen major oil fields were obtained from the Alberta Energy Resources Conservation Board (AERCB) through their information system on computer tapes. The total exploration and development footage drilled is given for each year for each of the 15 fields. Each well drilled is classified as either an exploration or a development well according to the Lahee classification.

There are four types of exploratory and three types of development wells. For our purposes, we do not distinguish between each of the categories within exploratory and development wells. However, we do state the different categories. The five types of exploratory wells are as follows:

(i) New Field Wildcat. A new field wildcat is a test located on a structural feature or other type of trap which has not previously produced oil or gas. In regions where local geological conditions have little or no control over accumulations, these tests are generally at least three kilometres from the nearest productive area. Distance, however, is not the determining factor. Of greater importance is the degree of risk assumed by the operator, and his intention to test a structure or stratigraphic condition not previously proved productive.

(ii) New Pool Wildcat. A new pool wildcat is a test located to explore for a new pool on a structural feature or other type of trap already producing oil or gas but outside the known limits of the presently producing area. In some regions where local geological conditions exert an almost negligible control, exploratory holes of this type may be called "near wildcats". Such wells will usually be less than three kilometres from the nearest productive well.

(iii) Deeper Pool Test. A deeper pool test is an exploratory hole located within the productive area of a pool or pools already partly or wholly developed. It is drilled below the deepest productive pools in order to explore for deeper unknown prospects.

(iv) Shallower Pool Test. A shallower pool test is an exploratory test drilled in search of a new productive reservoir, unknown but possibly suspected from data secured from other wells, and shallower than known productive pools. This test is located within the productive area of a pool or pools formerly developed.

(v) Outposts. An outpost is a test located and drilled with the expectation of extending for a considerable distance the productive area of a partly developed pool. It is usually two or more locations distant from the nearest productive site.

The three categories of development wells are as follows:

(i) Development Well. A development well is defined as a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. If the well is completed for production, it is classified as an oil or gas development well. If the well is not completed for production and is abandoned it is classified as a dry development well.

(ii) Development Portion of a Deep Pool Test. Prior to 1979 the footage drilled as a deeper pool test was split between the exploration and development categories. Since 1979, the entire drilled area under a deeper pool test is assigned to exploration.

(iii) Development Service Well. A service well is drilled or completed for the purpose of exploratory production in an existing field. Wells of this class are drilled for one or more of the following specific purposes: gas injection (natural gas, propane, butane), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation, and injection of in situ combustion materials.

The data on exploration and development footage drilled for the province of Alberta, over 1960-1979 were obtained from AERCB's Alberta Oil and Gas Industry - Annual Statistics (AERCB 80-17), 1972, 1979, Table A-1.

Production of Oil and Gas. The data on yearly production of oil and natural gas for each of the 15 fields were given by the Oil and Gas Departments of AERCB. The production of oil is given in cubic meters and the production of gas in millions of cubic metres. The data for the province of Alberta were obtained from Canadian Petroleum Association, Annual Statistics, 1980, Section III, Table 1 and Table 9.

Reserves of Oil and Gas: The data on reserves of oil and natural gas were obtained partly from AERCB and partly from the Geological Survey of Canada. The data on proved reserves for each field were provided by AERCB through their Reserves Reports. The data for Alberta were obtained from Tables A-4 and A-5 of AERCB's Reserve Reports, 1980.

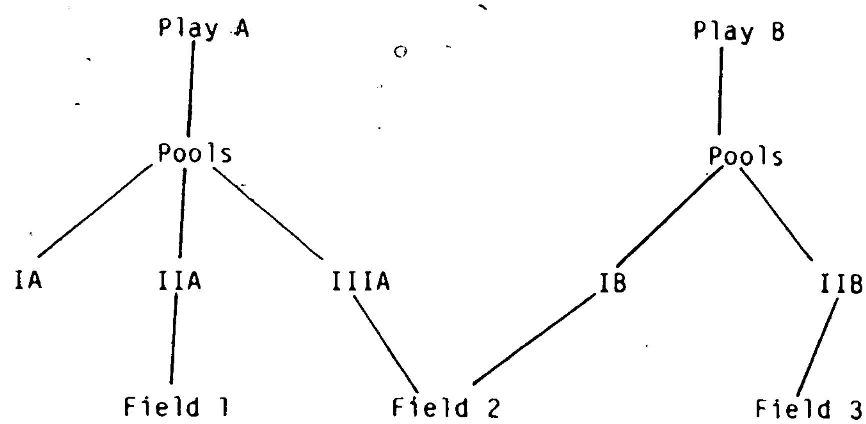
The data on probable reserves for both oil and gas for Alberta were obtained from Tables A-4 and A-5 of the AERCB Reserves Reports, 1979. Such data are not published by AERCB for individual fields.

Thus to generate estimates of probable reserves for individual fields first, we calculated a ratio of probable reserves found per successful foot drilled in Alberta. Second, we multiplied this provincial ratio with the successful footage drilled in the field being considered. This gave us probable reserves for that particular field. Note that this procedure was applied separately for oil and for gas reserves.

The data on undiscovered reserves (UDR) for both oil and gas pertaining to Alberta and to the 15 fields were calculated on the basis of information given by the Geological Survey of Canada (GSC). The UDR is that portion of the resource which is inferred to exist but has not yet been discovered and therefore not classified as either proved or probable reserves. The above definition of UDR is consistent with AERCB's definition of Ultimate Potential. The GSC estimates of UDR are expressed in a probability context. Thus we have UDR estimates with a high (90%) probability, a low (10%) probability, and a medium (50%) probability. The calculation of oil and gas reserves potential by the GSC involves (1) establishing the data input (2) generating pool size distribution, (3) evaluating play potentials, and (4) predicting discoveries . The data used include such geological characteristics as area of closure, reservoir thickness, effective porosity, net pay, trap well, recovery factor, water saturation, shrinkage factor, gas fraction, hydrocarbon fraction, and depth.

The UDR estimates are revised periodically and are given for a particular year. For Alberta, we took the 1977 estimates of UDR and generated data for the previous years (1960-1976) by adding the yearly proved reserves to each year. For example, to get the UDR estimates at the beginning of 1976, the proved reserves for 1976 were added to the UDR estimates for 1977. Similarly, to get estimates for 1978, the proved reserves generated in 1977 were subtracted from the UDR estimates for 1977.

To calculate the UDR for each field we first consider the data given by the GSC for each play. Any oil or gas play is said to consist of a group of prospects and/or discovered fields having common geological characteristics such as source rock, trapping mechanism, etc. Because of these similar characteristics it is assumed that the probability of finding oil and gas is uniform within a play. Each play consists of one or more pools, and each pool can further be assigned to a field. In some cases a field could consist of more than one play. Note that a field as opposed to a play relates to a geographical area - it is defined as a large tract or area containing valuable minerals. A play on the other hand, has a geological dimension - it is a natural underground potential container of oil, gas or water. It thus relates to potential oil or gas bearing formations. In a hypothetical example we may have:



The Geological Survey of Canada provides data for each play rather than for each field. To calculate the UDR data for each field we first identified the pools belonging to each play. Secondly, we took a ratio of proved reserves for Pool i to proved reserves for Play j (where Pool i belongs to Play j) and multiplied it by the UDR for Play j. This gave us the UDR for Pool i. Thirdly, we identified the pools belonging to each of the 15 fields and summed up the UDR for the relevant pools to get the UDR for each field. Finally, to generate data for each year we use the same procedure as followed for Alberta. The data on UDR for each field are given in Tables A-1 and A-2.

<u>Success Ratio</u>. The success ratio in this study is defined as the ratio of successful exploratory wells to total number of wells drilled. The source of this data is the same as that of total exploratory footage discussed above.

The expected success ratio for both the province and individual

TABLE A-1

UNDISCOVERED RESERVES FOR CRUDE OIL AT MEAN PROBABILITY

(mmstb)

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
Bonnie Glen	52.27	19.27	19.27	18.86	18.18	18.18	18.19	00	00	00	00	00	00	00	00
Ferrier	53.12	50.85	50.84	29.92	30.21	3.63	3.54	3.47	7.65	2.99	7.84	6.05	3.40	1.16	00
Judy Creek	59.15	59.15	59.15	59.15	59.15	58.07	58.52	58.51	56.52	30.52	30.51	30.52	30.25	27.58	27.59
Leduc	22.03	22.24	22.01	21.72	15.86	15.86	15.85	15.70	00	00	00	00	00	00	00
Pembina	82.29	50.54	47.05	56.95	34.38	00	45.47	46.91	26.75	22.27	20.08	198.28	195.03	178.21	133.23
Rainbow	804.90	597.90	421.27	312.66	190.36	154.91	150.31	157.48	156.56	141.56	128.28	132.48	132.04	132.26	134.14
Red Earth	41.74	27.52	15.16	12.33	12.23	11.41	11.37	7.69	8.52	8.23	9.53	9.33	9.25	8.88	8.75
Red Water	11.01	11.01	11.01	11.01	11.01	11.01	00	00	00	00	00	00	00	00	00
Ricinus	33.17	33.17	33.17	33.17	29.91	26.19	25.47	21.18	17.20	17.20	17.04	2.09	00	00	00
Swan Hills	2392.46	2250.46	2245.46	2196.46	2196.46	2196.46	2196.46	2195.46	2193.46	2180.46	2175.46	2174.46	2176.46	2170.39	2171.02
Turner Valley	102.57	102.57	102.57	102.57	102.57	92.57	92.57	92.57	92.57	92.57	92.57	92.06	92.00	91.51	91.45
Utikuna Lake	27.44	21.94	21.94	21.94	21.87	19.56	19.56	19.56	13.36	13.27	11.80	9.70	1.87	00	00
Virginia Hills	24.31	24.31	24.31	24.31	24.31	24.31	24.31	23.84	23.84	22.97	20.97	8.97	8.77	9.53	4.53
Wizard Lake	80.13	80.13	80.13	80.11	69.15	.15	.15	.15	.15	00	00	00	00	00	00
Zama	113.42	113.42	113.42	00 *	00	00	00	00	00	00	00	00	00	00	00

* Data not available.

TABLE A-2

UNDISCOVERED RESERVES FOR MARKETABLE NATURAL GAS AT MEAN PROBABILITY
(bcf)

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
Bonnie Glen	48.26	24.26	38.26	38.26	36.26	37.26	36.26	16.26	1.26	00	00	00	00	00	00
Ferrier	838.50	523.50	517.50	514.50	262.60	233.50	316.50	314.50	293.50	288.50	300.50	317.50	256.50	250.50	213.50
Judy Creek	370.76	332.76	307.76	306.76	306.76	277.76	291.76	291.76	285.76	265.76	255.76	254.76	254.76	245.76	245.76
Leduc	00	00	00	00	00	00	00	00	00	00	00	00	00	00	00
Pembina	319.78	552.78	550.78	476.78	484.78	566.78	722.78	704.78	660.78	646.78	650.78	645.78	580.78	532.78	517.78
Rainbow	332.66	270.66	00	00	00	00	00	00	00	00	00	00	00	00	00
Red Earth	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Red Water	00	00	00	00	00	00	00	00	00	00	00	00	00	00	00
Ricinus	1509.35	1509.35	1509.35	1289.35	1289.35	1168.35	1064.35	992.35	833.35	809.35	837.35	823.35	794.35	752.35	682.35
Swan Hills	920.85	840.85	840.85	860.85	860.85	860.85	850.85	850.85	850.85	850.85	812.85	812.85	812.85	808.35	806.85
Turner Valley	157.30	157.30	157.30	157.30	157.30	157.30	157.30	157.30	143.30	203.30	203.30	196.30	192.30	187.30	178.30
Utikuna Lake	12.68	12.68	12.68	12.68	12.68	12.68	12.68	12.68	12.68	12.68	12.68	2.68	.68	00	00
Virginia Hills	102.26	84.36	84.26	84.26	70.26	55.26	55.26	55.26	49.26	47.26	43.26	36.26	38.26	39.26	39.26
Zama	44.87	44.87	27.87	00 *	00	00	00	00	00	00	00	00	00	00	00

* Data not available.

fields is calculated by taking a weighted average of two years (current and prior) where the weights assigned are .7 and .3 for t and t-1 respectively.

Expected Profitability. The expected profitability in any time period is measured by the bonus bids paid per acre. The data for each field were obtained from the internal files of Alberta's Department of Energy and Natural Resources (ENR) oil and gas sales branch. The data for Alberta were obtained from various fall review and forecast issues of Oil Week (land activity section). The data on expected profitability for individual fields are given in Table A-3.

Land Sales (Acres Acquired). The number of acres acquired under the licences for each field was again obtained from the internal files of ENR's oil and gas sales branch. The data for Alberta, however, were obtained from the Annual Reports of Alberta's Department of ENR.

Market Demand Prorationing. The market demand prorationing is measured by the ratio of productive capacity (i.e. the maximum amount that can be produced given the maximum efficient rate) to actual production of oil. For Alberta the data on productive capacity and actual production of oil were obtained from AERCB Alberta Oil and Gas Picture - 1947-1974 and Selected Statistics (31st December, 1980) published by ERCB. Note that the data on productive capacity is calculated by adding the productive capacity of each well in the province. For fields the data were provided by AERCB.

TABLE A-3

EXPECTED PROFITABILITY FOR FIELDS ($/ACRE)

	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
1. Bonnie Glen (P)	-	-	-		-	-	-		-	-	-	-	-	24.98	-	-
2. Ferrier (F)	-	-	75.47	191.05	51.42	35.29	39.28	15.21	33.72	-	161.76	97.79	95.55	179.44	464	609.22
3. Judy Creek (C)	-	-	-	-	-	20.00	13.63	-	-	-	56.75	-	76.80	-	-	-
4. Leduc (P)	-	-	-	-	-	-	-	-	-	-	-	-	32.27	10.05	1375.96	99.41
5. Pembina (C)	120.44	115.85	75.87	44.18	66.16	25.06	34.04	33.43	63.84	58.36	60.57	75.92	104.29	221.71	408.68	115.22
6. Rainbow (N)	-	-	3892.26	794.69	714.06	123.15	231.89	58.89	185.60	62.44	-	40.28	87.67	26.56	69.31	169.14
7. Red Earth (N)	57.60	81.77	73.39	60.68	91.97	74.69	96.17	-	-	30.43	255.00	36.07	92.37	52.36	128.513	71.16
8. Red Water (P)	-	-	-	-	-	-	-	-	-	-	-	-	72.06	-	42.123	682.00
9. Ricinus (F)	-	-	-	-	-	831.45	327.59	-	426.46	80.98	-	-	139.99	-	144.29	-
10. Swan Hills (C)	273.10	144.70	272.40	192.75	-	-	-	178.82	57.45	135.00	142.93	-	124.75	346.73	-	239.60
11. Turner Valley (F)	-	-	-	-	-	92.00	-	-	-	-	12.07	139.86	86.80	-	-	637.87
12. Utikuna Lake (N)	-	220.81	26.00	121.84	117.56	49.39	67.42	99.00	-	-	20.05	80.95	52.05	98.07	376.78	-
13. Virginia Hills(C)	70.58	-	23.00	32.00	-	18.24	10.04	-	-	34.00	99.73	-	135.42	14.74	91.63	-
14. Wizard Lake (P)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15. Zama	-	-	-	798.81	3377.74	606.96	65.94	49.07	44.07	34.60	81.00	-	-	-	78.74	-

P = Plains
C = Central
N = Northern
F = Foothills

Prices: The average wellhead prices of oil and gas were obtained from the Canadian Petroleum Association - Annual Statistics, 1980, Section VI, Table 4. As the quality of the crude produced from the 15 fields does not vary significantly, we use the average wellhead price as applicable to individual fields. To calculate an average wellhead world price of oil we consider prices from five sources:

(a) Venezuela tia Juana - light

(b) Arab ex Sidon

(c) Arab ex Ras Tanura

(d) Arab Light

(e) Libya ex Marsa el Breja

The data on each of these five types were obtained from the July issues of Petroleum Economist. All these crudes are given equal weight. The quality of these crudes in terms of their sulphur and API content is similar to that of the average Alberta crude. To calculate the price of oil in Alberta relative to the world price we took a ratio of the average wellhead price of oil in Alberta to an average of the above five types of oil. Note that although a relative price of oil in Alberta vis-a-vis the average world price of oil was calculated, this variable was not used in the final estimating equations as it was found to be statistically less significant than the relative price of oil in Alberta vis-a-vis the average price in U.S. An average wellhead price of oil in the United States was calculated by taking an average of several different types of oil in the United States. The relative price of oil in Alberta vis-a-vis the United States was calculated by taking a ratio of the average wellhead price in Alberta to an average wellhead price of oil in the United States. The data on these different types of oil were again obtained from the July issues of Petroleum Economist.

The expected wellhead price of oil and gas for Alberta was calculated by taking a weighted average of time period t and t-1 where the weights are .7 and .3.

Interest Rate. Three alternative proxies for the rate of discount 'i' were used in the present study. First, 'i' was defined as the rate of return on equity in alternative industries. Alternative industries include of total mining, primary metals, metal fabricating, non-metallic mineral products, petroleum and coal products, chemical products and public utilities. These industries are assumed to provide an alternative to investment in the oil and gas industry, and hence the rate earned in these alternative industries is assumed to represent the opportunity cost of investment. The rate of return on equity was calculated by taking a ratio of net profits - including non-recurring items, less interest, depreciation and taxes - to total equity of shareholders and affiliates.

Second, 'i' was defined as the ratio of return on long term capital employed in the above industries. This was calculated by taking a ratio of the sum of after-tax profits interest payments on funded debt and non-recurring items, to the sum of long term liabilities, and equity, in the above industrial group. The data on these two proxy rates of return were obtained from annual issues of Corporation Financial Statistics, Statistics Canada 61-207, Table 2.

Lastly, 'i' was defined as the yield on Canadian government long term bonds. The data for this proxy were obtained from the December issues of International Financial Statistics, Canada section.

Relative Rate of Return in Alternative Industries. This was measured by the rate of return on capital employed in seven alternative industries consisting of total mining, primary metals, metal fabricating, non-metallic mineral products, petroleum and coal products, chemical products and public utilities. Note that this proxy for RP_{alt} coincides with the second proxy used for 'i' above.

Productivity in the Production Phase. This was measured by taking a ratio of the total output of the oil and gas industry, measured in $ 1971, to total amount spent on wages and salaries, again in $ 1971. The data were obtained from Statistics Canada.

The above measure of productivity suffers from an inherent bias: inasmuch as production is sensitive to prices, an increase in price would generate an increase in production, without necessarily increasing the amount of labour employed. This increase, which is primarily due to better utilization of capital, is attributed to labour, although it is never clear just how such an increment should be split and imputed to the various factors of production.

Retained Earnings. The retained earnings generated annually for the oil and gas industry are measured by the net profit after taxes. These data were obtained from the yearly issues of Statistics Canada Corporation Financial Statistics 61-207, Table 2. Note that the data are given for the Canadian oil and gas industry rather than the Alberta oil and gas industry. Data on retained earnings for individual fields were not available. In order to obtain data on this variable, we first calculated the total revenue generated for each field, and then deducted royalties and an estimate of corporate income tax from total revenue to obtain revenue after tax. This variable was then used as a proxy for retained earnings for the year.

Corporate Income Tax Rate, Royalty Rate, Write-offs and Allowances. The regulated corporate income tax rate applicable to all industries was used. These data were obtained from the yearly isues of Corporation Taxation Statistics, Statistics Canada 61-208. The exploration and development expenditure deduction rate was obtained from Holland, Schuill and Kemp, Canadian Taxation of Mining Income, Chapter 10, published by CCH Canadian Ltd. The provincial income tax rates were obtained from Principal Taxes in Canada - Annual Statistics, Statistics Canada 68-201. The average royalty rate for oil and for gas was obtained from the internal files of the Alberta Department of Energy and Natural Resources (ENR). The depletion and resource allowances were calculated from the information given in Breeding, Burke and Burton, Income Taxation of Natural Resources, published by Prentice Hall, 1977.

Costs. Much of the effort in this thesis was devoted to acquiring primary micro data directly from industry sources. In particular, a lot of effort was directed at establishing the cost data for individual fields. The first step in establishing these cost series was to calculate a cost series for each of the sub-components of the types of cost under consideration. The source and method of calculation of each of these sub-components are given below.

We consider three kinds of costs: exploration cost per foot, development cost per foot and operating cost per BTU of oil and gas. In line wth CPA methods each of these cost categories is divided into the following sub-components:

(1) Per foot cost of exploration

(a) per foot cost of exploratory drilling,

(b) per unit cost of seismic activity,

(c) per acre cost of rentals.

(2) Per foot cost of development

(a) per foot cost of development drilling,

(b) per foot cost of non-drilling capital employed.

2(b) above includes tangible well and lease equipment, pipeline and related facilities, secondary recovery and pressure maintenance projects, natural gas processing plants, office buildings, land and other machinery and equipment.

(3) Per barrel of oil cost of operating

(a) per barrel cost of surface equipment,

(b) per barrel cost of natural gas processing plant,

(c) per barrel cost of taxes (excluding corporate income tax).

3(a) includes field, well and gathering operation. We calculate each of these categories of cost by generating a cost series for each of the sub-components for each field for the years 1962-1979. The cost series is given for four zones: namely Plains, Central, Northern, and Foothills. Each of the 15 fields belong to one of the four zones. The Plains, Central and Northern zones have four fields, and the Foothills zone has three.

The per foot cost of exploration and development drilling and the per mile cost of seismic activity are obtained on the basis of information provided by six oil companies along with information held by the ENR under its Exploratory Drilling Program. In line with the drilling incentives program procedures, it is assumed that these costs differ significantly between the zones but are uniform within a zone for a given depth. (Note that the incentive credits are uniform within each zone for the same depth of well.) As the average depth of the oil fields differs widely we first establish the cost for each zone and then adjust it for average depth. Tables A-4 and A-5 respectively give the exploration and development drilling costs in the four zones for the period 1964-1979 for an average well depth in that zone. This average depth is calculated by taking an average of the depths of the four fields belonging to each zone (three in the case of Foothills). The depth-adjusted costs for each field are given in Tables A-6 and A-7. The depth adjustment factors are given in Tables A-8 and A-9.

The per mile cost of seismic activity is also obtained from information provided by the companies and the information held by ENR under its Geophysical Incentives Program. Table A-10 gives the seismic cost for the four zones over the period 1964-1979. The per acre cost of rentals is uniform throughout the province and was $1.00 per acre for the time period under consideration. The bonuses paid per acre on the leases and licenses for each field are for the years 1964-1979, and were derived from information available through the internal files of Alberta ENR.

The per foot cost of capital employed under the development cost category is obtained from the CPA annual statistics and is adjusted for depth by an adjustment factor. The road cost and natural gas plant cost are then added to obtain the total capital cost. The adjusted development capital costs are provided in Table A-11.

TABLE A-4

ESTIMATED EXPLORATORY DRILLING COST
($/FOOT)

Year	Plains	Central	Northern	Foothills
1964	13.16	16.44	20.94	43.99
1965	13.71	17.02	21.81	45.82
1966	14.77	18.43	24.38	49.70
1967	17.25	21.53	27.81	57.85
1968	18.50	23.10	29.98	61.13
1969	17.73	22.49	29.12	61.16
1970	18.64	23.93	30.71	64.89
1971	18.82	24.17	31.02	65.55
1972	19.83	25.18	33.64	68.40
1973	23.31	27.64	35.85	89.67
1974	26.30	47.18	42.13	100.91
1975	29.62	53.42	53.56	122.62
1976	34.34	49.04	76.83	145.48
1977	41.88	75.65	93.24	177.00
1978	49.97	115.58	92.83	234.78
1979	68.84	137.96	123.89	281.71
1980	91.42	141.14	169.70	365.71

TABLE A-5

ESTIMATED DEVELOPMENT DRILLING COST

($/FOOT)

Year	Plains	Central	Northern	Foothills
1964	11.19	13.97	17.80	37.39
1965	11.65	14.47	18.54	38.95
1966	12.55	15.67	20.72	42.25
1967	14.66	18.30	23.64	49.17
1968	15.73	19.64	25.48	51.96
1969	15.07	19.12	24.75	51.99
1970	15.84	20.34	26.10	55.16
1971	16.00	20.54	26.37	55.72
1972	16.86	21.40	28.59	58.14
1973	19.81	23.49	30.47	76.22
1974	22.36	40.10	35.81	85.77
1975	25.18	45.41	45.53	104.23
1976	29.19	41.68	65.31	122.66
1977	35.60	64.30	79.25	150.45
1978	42.47	98.24	78.91	199.56
1979	58.51	117.27	105.31	239.45
1980	77.71	119.97	144.25	310.85

TABLE A-6

DEPTH ADJUSTED EXPLORATORY DRILLING COST FOR FIELDS ($/FOOT)

	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
1. Bonnie Glen (P)	13.29	13.84	14.91	17.42	18.68	17.90	18.82	19.00	20.02	23.54	26.56	29.91	34.68	42.29	50.46	69.52
2. Ferrier (F)	43.99	45.82	49.70	57.85	61.16	61.16	64.89	65.55	68.40	89.67	100.91	122.62	145.48	177.00	234.78	231.71
3. Judy Creek (C)	15.78	16.33	17.69	20.66	22.17	21.55	22.97	23.20	24.17	26.53	45.29	51.28	47.07	72.62	110.95	132.44
4. Leduc (P)	15.66	16.31	17.57	20.52	22.01	21.09	22.18	22.39	23.59	27.73	31.29	35.24	40.86	49.83	59.46	81.91
5. Pembina (C)	16.11	16.67	16.67	21.09	22.04	22.04	23.45	23.68	24.67	27.08	46.23	51.41	48.05	74.13	113.26	135.20
6. Rainbow (N)	20.10	20.93	23.89	27.25	27.95	27.95	29.48	29.77	32.29	34.41	40.44	52.35	73.75	89.51	89.11	118.93
7. Red Earth (N)	19.74	20.28	23.40	25.86	27.08	27.08	28.56	28.84	31.28	33.34	39.18	49.81	71.45	86.71	86.33	115.21
8. Red Water (P)	9.34	9.73	10.48	12.24	13.13	12.58	13.23	13.36	14.07	16.55	18.67	21.03	24.38	29.73	35.47	48.87
9. Ricinus (F)	51.90	54.06	58.64	68.26	72.16	72.16	76.57	77.34	80.71	105.81	119.07	144.69	171.66	208.86	277.04	332.41
10. Swan Hills (C)	18.41	19.06	19.06	24.11	25.18	25.18	26.80	27.07	28.20	30.95	52.84	59.83	54.92	84.72	129.44	154.51
11. Turner Valley (F)	29.47	30.69	33.29	38.75	40.97	40.97	43.47	43.91	45.82	60.06	67.60	82.15	97.47	118.59	157.30	188.74
12. Utikuma Lake (N)	25.96	27.04	30.23	34.48	36.10	36.10	38.08	38.46	41.71	44.45	52.40	66.41	95.26	115.61	115.10	153.62
13. Virginia Hills (C)	20.71	21.44	21.44	27.12	28.33	28.33	30.15	30.46	31.72	34.82	59.44	67.30	61.79	95.31	145.63	173.82
14. Wizard Lake (P)	15.79	16.45	17.72	20.70	22.20	21.27	22.36	22.58	23.79	27.97	31.56	35.54	41.20	50.25	59.96	82.60
15. Zama	24.29	25.29	28.28	32.25	33.77	33.77	35.62	35.98	39.02	41.58	48.87	62.12	88.42	108.15	107.68	143.71

P = Plains
C = Central
N = Northern
F = Foothills

TABLE A-7

DEPTH ADJUSTED DEVELOPMENT DRILLING COST FOR FIELDS ($/FOOT)

	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
1. Bonnie Glen (P)	15.44	16.07	17.31	20.23	21.70	20.79	21.85	22.08	23.26	27.33	30.85	34.74	40.28	49.12	58.60	80.74
2. Ferrier (F)	37.39	38.95	43.09	50.15	52.99	53.02	56.26	56.83	59.30	77.74	87.48	106.31	125.11	153.45	203.55	244.23
3. Judy Creek (C)	13.27	13.74	14.88	17.38	18.65	18.16	19.32	19.51	20.33	22.31	38.09	43.11	39.59	61.08	93.32	111.40
4. Leduc (P)	11.52	11.99	12.92	15.09	16.20	15.52	16.31	16.48	17.36	20.40	23.03	25.93	30.06	36.66	43.74	60.26
5. Pembina (C)	10.61	10.99	11.90	13.90	14.92	14.53	15.45	15.61	16.26	17.85	30.47	34.51	31.67	48.86	74.76	89.12
6. Rainbow (N)	17.26	17.98	20.09	22.93	24.71	24.00	25.31	25.57	27.73	29.55	34.73	44.16	63.35	76.87	76.54	102.15
7. Red Earth (N)	17.08	17.79	19.89	22.69	24.46	23.76	25.05	25.31	27.44	29.25	34.37	43.70	62.69	76.08	75.75	101.09
8. Red Water (P)	7.16	7.45	8.03	9.38	10.06	9.64	10.13	10.24	10.79	12.67	14.31	16.11	18.68	22.78	27.18	37.44
9. Ricinus (F)	44.43	46.35	50.27	58.51	61.83	61.86	65.64	66.30	69.18	90.70	102.06	124.03	145.96	179.03	237.47	284.94
10. Swan Hills (C)	15.64	19.53	21.15	24.70	26.51	25.81	27.45	27.72	28.89	31.71	54.13	61.30	56.26	86.80	132.62	158.31
11. Turner Valley (F)	25.42	26.48	28.73	33.43	35.33	35.35	37.50	37.88	39.53	51.82	58.32	124.03	83.40	102.30	135.70	162.82
12. Utikuna Lake (N)	22.07	21.87	24.44	27.89	30.06	29.20	30.79	31.11	33.73	35.95	42.25	53.72	77.06	93.51	93.11	124.26
13. Virginia Hills(C)	17.60	17.65	19.11	22.32	23.96	23.32	24.81	25.05	26.10	28.65	48.92	55.40	50.84	78.44	119.85	158.31
14. Wizard Lake (P)	13.42	15.84	17.06	19.93	21.39	20.49	21.54	21.76	22.92	26.94	30.40	34.24	39.69	48.41	57.75	79.57
15. Zama	20.64	18.91	21.13	24.11	25.98	25.24	26.62	26.89	29.16	31.07	36.52	42.44	66.16	80.83	80.48	107.41

P = Plains
C = Central
N = Northern
F = Foothills

TABLE A-8

PER FOOT EXPLORATORY DEPTH ADJUSTMENT FACTOR

Bonnie Glen	1.01
Ferrier	1.00
Judy Creek	.96
Leduc	1.19
Pembina	.98
Rainbow	.96
Red Earth	.93
Red Water	.71
Ricinus	1.18
Swan Lake	1.12
Turner Valley	.67
Utikune Lake	1.24
Virginia Hills	1.26
Wizard Lake	1.20
Zamer	1.16

Note: This adjustment factor is calculated by taking a ratio of the average exploratory well depth of respective fields to the average well depth of the respective zone.

TABLE A 9

PER FOOT DEVELOPMENT DRILLING AND CAPITAL COST DEPTH ADJUSTMENT FACTOR

	Drilling Cost	K-Cost
Bonnie Glen	1.38	1.76
Ferrier	1.02	1.72
Judy Creek	.95	1.56
Leduc	1.03	1.24
Pembina	.76	1.24
Rainbow	.97	1.21
Red Earth	.96	1.15
Red Water	.64	.78
Ricinus	1.19	2.20
Swan Lake	1.35	1.98
Turner Valley	.68	1.13
Utikume Lake	1.18	1.56
Virginia Hills	1.22	2.07
Wizard Lake	1.36	1.72
Zama	1.02	1.23

Note: The drilling factor is calculated by taking the ratio of the average development well depth of respective field to an average well depth of the respective zones.

TABLE A-10

ESTIMATED SEISMIC COSTS
($/SEISMIC MILE)

Year	Plains	Central	Northern	Foothills
1964	752.24	862.17	1115.63	2731.45
1965	827.47	948.39	1227.20	3004.60
1966	1058.83	1217.66	1608.35	3854.78
1967	1116.51	1422.70	1857.22	4502.63
1968	1380.00	1760.47	2368.51	5568.51
1969	1366.23	1742.40	2285.49	5512.95
1970	1206.94	1540.28	2022.43	4871.19
1971	1610.65	2060.61	2724.41	6509.43
1972	2132.56	2734.84	3652.90	8630.01
1973	3608.48	4670.35	6436.25	14677.25
1974	2900.16	3758.71	5203.50	11806.25
1975	3466.51	4497.35	6247.13	14118.55
1976	3132.29	4065.01	5652.36	12759.55
1977	2686.77	3489.29	4863.60	10949.02
1978	2304.91	4710.73	4245.63	9503.80
1979	2596.63	3416.50	4793.15	10711.50
1980	3588.40	4740.89	6724.86	14841.34

TABLE A-11

ACCESSABILITY AND DEPTH ADJUSTED DEVELOPMENT CAPITAL COST FOR FIELDS ($/FOOT)

	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
1. Bonnie Glen (P)	12.87	17.01	23.95	39.99	47.28	60.00	94.26	94.84	64.76	48.67	59.02	61.68	85.07	73.41	82.84	86.18
2. Ferrier (F)	18.14	22.40	30.07	47.44	54.34	66.94	91.19	103.31	70.49	53.84	64.68	68.83	95.71	84.40	96.98	102.97
3. Judy Creek (C)	14.59	18.44	25.46	41.59	48.04	59.71	83.80	94.99	63.20	47.34	57.70	60.74	83.52	73.08	83.13	87.47
4. Leduc (P)	10.31	13.44	19.84	33.94	39.30	49.13	72.90	82.99	51.91	37.28	47.00	48.49	65.18	56.57	63.30	65.75
5. Pembina (C)	12.95	16.16	22.94	37.72	42.93	52.76	76.53	87.38	54.98	40.05	50.01	52.26	70.79	62.30	70.63	74.40
6. Rainbow (N)	12.65	16.09	22.85	37.56	42.65	52.31	76.04	86.92	54.39	39.51	49.46	51.69	69.92	61.61	69.88	73.67
7. Red Earth (N)	12.64	15.66	22.32	36.84	41.69	51.00	74.68	85.49	52.85	38.15	49.02	50.77	67.53	59.59	67.30	71.22
8. Red Water (P)	7.95	10.15	15.79	28.37	31.96	39.13	62.44	72.06	40.09	26.80	35.94	36.49	46.88	40.08	45.32	46.95
9. Ricinus (F)	21.63	26.91	35.83	54.75	63.44	78.82	103.53	116.47	84.05	65.87	77.41	82.71	117.03	102.93	118.70	126.00
10. Swan Hills (C)	17.44	22.17	30.24	47.69	55.71	69.82	94.32	106.13	74.32	57.63	68.61	72.59	101.74	88.75	101.51	106.94
11. Turner Valley (F)	14.60	17.65	24.58	39.55	44.22	53.42	77.06	88.46	54.74	39.86	49.91	52.55	70.83	63.41	72.57	77.17
12. Utikuna Lake (N)	14.59	18.44	25.76	41.59	48.04	59.71	83.80	94.99	63.20	47.34	57.70	60.62	83.52	73.08	83.13	87.47
13. Virginia Hills (C)	17.90	22.81	31.09	48.78	57.15	71.77	96.96	108.27	77.13	59.68	70.77	74.97	105.03	91.79	105.03	110.62
14. Wizard Lake (P)	12.77	16.87	24.07	39.75	46.96	59.56	83.81	94.40	64.24	48.21	58.54	61.02	84.28	72.74	82.06	85.36
15. Zama	13.05	16.23	23.03	37.81	42.97	52.74	76.50	87.39	54.90	39.97	49.94	52.21	70.71	62.29	70.66	74.49

P = Plains
C = Central
N = Northern
F = Foothills

The per unit costs of taxes, surface equipment and natural gas processing plant are given in Table A-12. The surface equipment costs are adjusted for each field, and then the above two components are added to arrive at the operating cost per barrel. These costs are given in Table A-13.

Once the above series were established two alternative approaches were experimented with to arrive at the per foot cost of exploration and development.

A) Regression method. In this method we run the exploration and development cost functions for Alberta and then use these macro parameters to predict cost for each field. Several specifications of cost functions, (viz. translog, log linear and linear functions), were estimated. The translog function did not work well due to high multicollinearity between the 2nd and 1st order terms. Here we state the results obtained from the log linear and linear functions:

$$
\begin{aligned}
C_E = -187.35 &+ .00002Y_1 + .000028Y_2 + 10.932W_1 \\
(8.74) &\quad (.279) \qquad\quad (.9851) \qquad\quad (4.90) \\
&- 1278.27W_2 + .00001\ CWXT - .0209\ D1 \\
&\quad (1.62) \qquad\quad (2.23) \qquad\qquad (-.59)
\end{aligned}
$$

$$R^2 = .94 \quad R^2 = \quad 3 \quad D.W. = 1.31 \quad d\ of\ f = 18$$

TABLE A-12

ESTIMATED OPERATING COST COMPONENTS FOR ALBERTA

($ PER BARREL OF OIL)

Year	Surface Equipment Cost	Taxes	Natural Gas Process Plant Cost
1965	.25	.03	.12
1966	.25	.03	.12
1967	.23	.03	.13
1968	.24	.03	.13
1969	.21	.03	.12
1970	.24	.02	.13
1971	.26	.03	.16
1972	.26	.03	.15
1973	.29	.08	.18
1974	.32	.10	.23
1975	.45	.13	.27
1976	.55	.13	.34
1977	.66	.15	.41
1978	.84	.15	.41
1979	1.03	.15	.42

Note: This Surface Equipment Cost is adjusted for average well depth for each field by using the K.W. adjustment factor in table A-5B. Taxes and Natural Gas Plant Costs are then added to arrive at final operating cost. These operating costs are given in Table 7.

TABLE A-13

ESTIMATED OPERATING COST FOR FIELDS ($ PER BARREL OF OIL)

	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
1. Bonnie Glen (P)	.63	.58	.58	.56	.57	.51	.57	.63	.64	.68	.81	1.11	1.35	1.61	2.02	2.36
2. Ferrier (F)	.63	.58	.58	.56	.57	.51	.57	.63	.64	.68	.81	1.11	1.35	1.16	2.02	2.36
3. Judy Creek (C)	.59	.54	.54	.51	.53	.47	.53	.58	.59	.63	.75	1.03	.125	1.49	1.87	2.17
4. Leduc (P)	.50	.46	.46	.44	.45	.41	.45	.50	.51	.53	.65	.88	1.08	1.28	1.60	1.84
5. Pembina (C)	.50	.46	.46	.44	.45	.41	.45	.50	.51	.53	.65	.88	1.08	1.28	1.60	1.84
6. Rainbow (N)	.49	.45	.45	.43	.45	.40	.45	.49	.50	.53	.64	.87	1.06	1.26	1.57	1.81
7. Red Earth (N)	.48	.43	.43	.42	.43	.39	.43	.47	.48	.51	.62	.86	1.03	1.22	1.52	1.75
8. Red Water (P)	.38	.34	.34	.33	.34	.31	.34	.38	.39	.40	.50	.68	.82	.98	1.21	1.37
9. Ricinus (F)	.76	.70	.70	.66	.68	.61	.68	.75	.76	.81	.96	1.32	1.61	1.92	2.40	2.83
10. Swan Hills (C)	.70	.64	.64	.61	.63	.56	.63	.69	.70	.75	.89	1.22	1.48	1.77	2.22	2.60
11. Turner Valley (F)	.47	.43	.43	.41	.43	.38	.43	.47	.48	.50	.62	.83	1.02	1.21	1.50	1.73
12. Utikuna Lake (N)	.59	.54	.54	.51	.53	.47	.53	.58	.59	.63	.75	1.03	1.25	1.49	1.87	2.17
13. Virginia Hills(C)	.72	.66	.66	.63	.65	.58	.65	.71	.72	.78	.92	1.26	1.53	1.83	2.29	2.70
14. Wizard Lake (P)	.63	.58	.58	.55	.57	.51	.57	.62	.63	.67	.81	1.10	1.34	1.60	2.00	2.34
15. Zama	.50	.45	.45	.44	.45	.40	.45	.49	.50	.53	.65	.88	1.07	1.28	1.59	1.83

P = Plains
C = Central
N = Northern
F = Foothills

$$\log C_E = \underset{(.66)}{1.74} + \underset{(1.40)}{.0679} \log Y_1 + \underset{(.983)}{.060} \log Y_2$$

$$+ \underset{(7.74)}{.963} \log W_1 - \underset{(-.953)}{.184} \log W_2 + \underset{(.887)}{.000056D1}$$

$$+ \underset{(2.148)}{.056t}$$

$R^2 = .935$ $\bar{R}^2 = .915$ D.W. = 2.41 d of f = 18

In the above, C_E is the per foot cost of exploration; Y_1 and Y_2 are respectively the probable reserves of oil and gas; W_1 and W_2 are respectively the per foot cost of exploratory driling and per acre cost of seismic; D1 is the average depth of exploratory well in the province; CWXT is the cumulative number of wells drilled; and t is a time variable.

$$C_D = \underset{(1.49)}{143.05} - \underset{(-1.305)}{.00026Y_3} + \underset{(1.316)}{.0074Y_4} + \underset{(3.378)}{2.919V_1} + \underset{(3.211)}{1.336V_2}$$

$$- \underset{(-1.347)}{.0233D2}$$

$R^2 = .99$ $\bar{R}^2 = .99$ D.W. = 1.61 d of f = 19

$$\log C_D = 1.94 + \underset{(1.958)}{.080} \log Y_3 + \underset{(1.651)}{.10} \log Y_4$$

$$+ \underset{(5.74)}{.96} \log V_1 - \underset{(-.59)}{.070} \log V_2 + \underset{(-1.509)}{.00010D}$$

$$+ \underset{(1.517)}{.028t}$$

$R^2 = .94$ $\bar{R}^2 = .92$ D.W. = 1.68 d of f = 18

Again, in the above, Y_3 and Y_4 are respectively the reserves of oil and gas; V_1 and V_2 are respectively the per foot cost of development drilling and the per foot capital cost of development drilling; D is the average depth of a development well; and t is a time variable.

Note that in all the four equations, the cost of exploration and the cost of development are explained well by the independent variables considered in the equations. R^2 varies from .93 to .99. Cost of exploration is most sensitive to changes in the per foot drilling cost of exploration and the cumulative number of wells drilled in the province. The positive coefficient on CWXT indicates that the exploratory costs per foot in Alberta are increasing with further drilling implying that the cost of reserves discovered is increasing over time.

The cost of development is most sensitive to changes in the per foot cost of development drilling and per foot capital cost of development drilling. The aim here was to use the above macro coefficients along with the cost series generated above to predict the per foot cost of exploration and development for each field. As the use of these coefficients introduces an aggregation bias we followed Theil's method. Though this method reduces this bias it requires that the dependent variable for the micro units be available. As the dependent variables are the per foot cost of exploration and per foot cost of development, they are not available for each field. Thus despite good results for the macro data this method was discarded and we followed the second method.

B) <u>Ratio Allocation Method</u>. Given the various cost series for subcomponents, we calculate the per foot cost of exploration, per foot cost of development, and per unit cost of operating, for each of the 15 fields for the years 1964-1979. The per foot cost of exploration for the i^{th} field is calculated as:

$$C_{E\ ti} = \frac{TC_{E\ ti}}{F_{E\ ti}}$$

$$= [F_{E\ ti} \times \text{Cost per foot of exploratory drilling} + \text{total seismic miles covered} \times \text{cost per mile of seismic} + \text{total acres of land held} \times \text{rental per acre}]/F_{E\ ti}$$

where $C_{E\ ti}$ is the per foot cost of exploratory drilling in t for the i^{th} field, $TC_{E\ ti}$ is the total cost of exploration in t for the i^{th} field, and $F_{E\ ti}$ is the total exploratory footage drilled for the i^{th} field. The data on total exploratory footage drilled are obtained from the AERCB. The total number of acres of land held under each field is obtained from the Oil and Gas Sales Branch of ENR. The data relating to individual fields for the total miles of seismic activity are however not available directly. To construct them we consider a ratio of seismic miles covered per exploratory foot drilled in Alberta. This ratio is then multiplied by total exploratory footage drilled for each field.

To construct the per foot cost of development for the i^{th} field we consider:

$$
\begin{aligned}
C_{D\ ti} &= \frac{TC_{D\ ti}}{F_{D\ ti}} \\
&= [F_{D\ ti} \times \text{cost per foot of development drilling} \\
&\quad + F_{D\ ti} \times k \text{ per foot capital cost of development drilling}]/F_{D\ ti}
\end{aligned}
$$

where $C_{D\ ti}$ is the per foot cost of development drilling in t for the i^{th} field, $TC_{D\ ti}$ is the total cost of development in t for the i^{th} field, and FD_{ti} is the total footage drilled in t for the i^{th} field.

Finally the per unit cost of operating for the i^{th} field is constructed as follows:

$$
\begin{aligned}
C_{N\ ti} = &\ \text{Per barrel of oil cost of surface equipment} \\
&+ \text{per barrel cost of taxes (excluding corporate income tax)} \\
&+ \text{per barrel cost of natural gas processing plant}
\end{aligned}
$$

where $C_{N\ ti}$ is the per barrel cost of operating in t for the i^{th}

TABLE A-14

AGGREGATE EXPLORATION COST FOR FIELDS (EXCLUDING BONUSES) ($/FOOT)

	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
1. Bonnie Glen (P)	-	18.88	-	-	-	-	-	-	-	-	-	40.48	-	50.48	-	77.44
2. Ferrier (F)	-	54.98	61.45	71.58	78.13	77.97	-	85.39	76.29	103.09	111.73	135.53	184.38	210.38	263.76	314.37
3. Judy Creek (C)	-	-	-	29.34	-	-	32.36	-	-	40.77	56.75	-	59.46	23.25	-	-
4. Leduc (P)	20.26	21.36	-	27.33	30.42	29.42	29.54	27.30	30.09	38.73	40.13	45.80	50.41	58.02	66.28	89.83
5. Pembina (C)	21.37	22.45	24.09	29.77	32.77	32.66	32.84	29.96	33.01	41.32	57.69	65.12	60.44	84.77	114.70	145.62
6. Rainbow (N)	23.50	24.67	28.79	32.91	35.17	34.92	35.65	38.08	35.63	40.30	45.20	58.06	90.98	104.34	102.40	133.54
7. Red Earth (N)	23.14	24.02	28.30	31.52	34.30	34.05	34.73	37.16	-	39.23	43.94	-	88.68	95.36	102.40	129.83
8. Red Water (P)	13.93	14.77	-	19.05	17.37	20.91	20.59	18.27	20.57	17.69	27.51	31.59	33.63	37.92	42.50	56.79
9. Ricinus (F)	-	-	-	-	89.14	88.97	91.42	97.20	88.60	119.25	129.92	157.93	-	242.24	330.13	365.07
10. Swan Hills (C)	21.04	24.84	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11. Turner Valley (F)	-	-	-	-	-	-	-	-	53.71	73.50	-	-	-	151.97	186.27	-
12. Utikuna Lake (N)	-	30.78	35.13	-	-	-	-	46.77	45.05	50.34	-	-	79.02	130.44	128.04	168.23
13. Virginia Hills (C)	25.97	-	-	-	-	39.95	39.54	36.73	-	-	70.90	-	-	-	-	-
14. Wizard Lake (P)	20.34	-	24.18	-	-	-	-	-	-	-	-	-	-	-	-	-
15. Zama	-	-	33.20	37.91	40.99	40.74	41.79	44.29	42.36	47.47	53.63	-	127.31	122.97	120.63	-

P = Plains
C = Central
N = Northern
F = Foothills

TABLE A-15

AGGREGATE EXPLORATORY COST FOR FIELDS (INCLUDED LAGGED BONUS BIDS) ($/FOOT)

	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
1. Bonnie Glen (P)	-	61.94	-	-	-	-	-	-	-	-	-	132.77	-	165.59	-	253.99
2. Ferrier (F)	-	180.34	201.56	249.75	794.27	270.14	-	289.71	252.83	344.81	366.48	514.38	264.52	700.53	978.59	1031.11
3. Judy Creek (C)	-	-	-	96.22	-	-	107.70	-	-	133.80	186.13	-	195.02	307.51	-	-
4. Leduc (P)	-	70.05	-	89.63	99.79	96.50	96.89	89.55	98.71	127.04	131.64	150.30	165.34	193.86	220.95	300.89
5. Pembina (C)	-	95.75	143.93	391.54	133.38	137.78	113.11	131.75	145.47	138.36	244.61	308.49	226.84	296.16	431.71	658.15
6. Rainbow (N)	-	80.92	94.44	190.36	168.66	659.99	159.20	168.79	120.06	190.79	170.19	190.48	300.49	536.47	1553.15	622.17
7. Red Earth (N)	-	102.32	145.89	112.98	189.72	156.67	155.70	244.48	-	128.69	153.88	-	294.67	155.07	377.88	457.96
8. Red Water (P)	-	48.46	-	62.48	56.96	68.59	67.53	59.93	67.48	58.02	90.25	103.66	143.59	156.80	139.42	201.18
9. Ricinus (F)	-	-	-	-	292.39	291.81	818.89	333.62	290.62	515.37	449.20	517.09	-	802.33	1082.86	1278.07
10. Swan Hills (C)	-	738.18	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11. Turner Valley (F)	-	-	-	-	-	-	-	-	176.18	241.19	-	-	-	508.96	611.10	-
12. Utikuna Lake (N)	-	100.96	352.95	-	-	-	-	184.62	165.65	165.15	-	-	274.02	449.05	455.35	690.63
13. Virginia Hills (C)	-	-	-	-	-	127.77	134.79	130.48	-	-	234.52	-	-	-	-	-
14. Wizard Lake (P)	-	-	79.30	-	-	-	-	-	-	-	-	-	-	-	-	-
15. Zama	-	-	108.89	124.35	316.28	2092.09	2187.47	148.88	143.93	161.40	228.13	-	417.57	403.53	395.65	-

P = Plains
C = Central
N = Northern
F = Foothills

TABLE A-16

AGGREGATE DEVELOPMENT COST FOR FIELDS ($/FOOT)

	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
1. Bonnie Glen (P)	28.31	33.08	41.26	60.21	68.48	60.79	106.11	116.92	88.02	76.00	89.86	96.42	125.35	122.53	141.44	166.92
2. Ferrier (F)	55.53	61.35	73.16	97.59	107.33	119.96	147.45	160.14	129.79	131.58	152.16	175.14	221.12	237.85	300.53	347.20
3. Judy Creek (C)	27.86	32.18	40.34	58.97	66.69	77.86	103.12	114.50	83.53	69.65	95.79	103.87	123.11	134.16	176.45	198.87
4. Leduc (P)	21.83	24.43	32.76	49.03	55.50	64.65	89.12	99.47	69.27	57.68	70.03	74.42	95.24	93.23	107.04	126.01
5. Pembina (C)	23.56	27.15	34.84	51.62	57.85	69.29	91.98	102.99	71.24	57.90	80.48	86.77	102.46	111.16	145.29	163.52
6. Rainbow (N)	29.91	34.07	42.94	59.77	67.36	76.31	101.35	112.49	82.12	69.06	84.19	95.85	133.27	138.48	146.42	175.82
7. Red Earth (N)	29.72	33.45	42.21	59.53	66.15	74.76	99.73	110.80	80.29	67.40	82.39	94.47	130.22	135.67	143.05	172.31
8. Red Water (P)	15.11	17.60	23.82	37.75	[illegible]	48.77	72.57	82.30	50.88	39.47	50.25	52.40	65.56	63.86	72.50	84.39
9. Ricinus (F)	66.06	73.26	86.10	113.26	125.27	140.68	169.17	182.77	153.23	156.57	179.47	206.74	262.99	281.86	356.17	410.94
10. Swan Hills (C)	33.08	41.70	51.44	72.39	82.22	95.63	121.77	134.19	103.71	89.34	122.74	133.89	158.00	175.56	234.13	265.25
11. Turner Valley (F)	40.02	44.13	53.31	72.98	79.44	88.77	114.57	126.34	94.27	91.68	108.23	176.58	154.23	165.71	208.27	239.99
12. Utikuma Lake (N)	36.66	40.31	50.20	69.48	78.10	88.91	114.59	126.10	96.93	83.29	99.95	114.34	160.58	166.59	176.24	211.73
13. Virginia Hills (C)	35.50	40.46	50.20	71.10	81.11	95.09	121.17	133.32	103.23	88.33	119.69	130.34	156.17	170.23	224.88	268.93
14. Wizard Lake (P)	26.19	32.71	41.13	59.68	68.35	80.05	105.35	116.16	87.16	75.15	88.94	95.26	123.97	121.15	139.81	164.93
15. Zama	33.69	35.14	44.16	61.92	68.95	77.98	103.12	114.28	84.06	71.04	86.46	98.65	137.32	143.12	151.14	181.90

P = Plains
C = Central
N = Northern
F = Foothills

field. The per foot costs of exploration and development for each field are given in Tables A-14, A-15, and A-16. The operating cost per barrel of oil is given in Table A-13. The cost data for the province of Alberta were calculated from the CPA Annual Statistics, 1980, Section IV, Tables 3, 3A and 3B.

NOTES.

1. These Oil companies are Aquitaine, Canadian Hunter, Esso Resources, Home Oil, Husky Oil and Texaco. A copy of the questionnaire sent to these companies is in Appendix C.

APPENDIX B: DERIVATION OF THE MODEL AND NOTATIONS USED

In the following appendix, we derive the model and the estimating equations as specified in Chapter IV. The notations used and the definition of some specific variables are attached at the end of this appendix.

$$
\begin{aligned}
L = \int\{[e^{-it}(PQ - C_E \cdot E - C_D \cdot D - C_N \cdot N) \\
&+ \lambda_1(t)(Q - A_1K_2{}^mN^n) \\
&+ \lambda_2(t)[\dot{K}_2 - A_2K_1{}^\gamma D^\delta + Q] \\
&+ \lambda_3(t)[\dot{K}_1 - A_3E^\alpha]\}dt
\end{aligned}
$$

Differentiating the above Lagrangian with respect to the various variables we have,

$$\frac{\partial L}{\partial Q} = e^{-it}P + \lambda_1(t) + \lambda_2(t) = 0 \quad \text{- - - - - - - - - - - -} \quad (a)$$

$$\frac{\partial L}{\partial E} = -e^{-it}C_E - \lambda_3(t)\alpha E^{\alpha-1} = 0 \quad \text{- - - - - - - - - - - -} \quad (b)$$

$$\frac{\partial L}{\partial D} = -e^{-it}C_D - \lambda_2(t)\delta K_1{}^\gamma D^{\delta-1} = 0 \quad \text{- - - - - - - - - - -} \quad (c)$$

$$\frac{\partial L}{\partial N} = -e^{-it}C_N - \lambda_1(t)nA_1K_2{}^mN^{n-1} = 0 \quad \text{- - - - - - - - - -} \quad (d)$$

$$\frac{\partial L}{\partial K_2} - \frac{d}{dt}\frac{\partial L}{\partial \dot{K}_2} = -\lambda_1(t)mA_1K_2{}^{m-1}N^n + \frac{d}{dt}\lambda_2(t) \quad \text{- - - - - - -} \quad (e)$$

$$\frac{\partial L}{\partial K} - \frac{d}{dt}\ \frac{\partial L}{\partial \dot{K}} = -\lambda_2(t)\ k_1^{r-1}D^{\delta} + \frac{d}{dt}\ \lambda_3(t) \quad ------- \quad (f)$$

$$\frac{\partial L}{\partial \lambda_1} = Q - A_1 K_2^{m} N^{n} = 0 \quad ------------------ \quad (g)$$

$$\frac{\partial L}{\partial \lambda_2} = K_2 = \dot{K}_1^{\gamma} D^{\delta} - Q = 0 \quad --------------- \quad (h)$$

$$\frac{\partial L}{\partial \lambda_3} = \dot{K}_1 - E^{\alpha} = 0 \quad ---------------------- \quad (i)$$

from (a) we have

$$e^{-it}P + \lambda_1(t) + \lambda_2(t) = 0 \quad -------------- \quad (a)$$

from (e) we have

$$\dot{\lambda}_2(t) = \lambda_1(t) m A_1 K_2^{m-1} N^{n} \quad -------------- \quad (i)$$

Differentiating (a) with respect to time, we have

$$e^{-it}\dot{P} - ie^{-it}P + \dot{\lambda}_1 + \dot{\lambda}_2 = 0 \quad -------------- \quad (ii)$$

Substituting (i) into (ii) we get

$$e^{-it}\dot{P} - ie^{-it}P + \dot{\lambda}_1 + \lambda_1 A_1 m K_2^{m-1} N^{n} = 0 \quad --------- \quad (iii)$$

Simplify $A_1 m K_2^{m-1} N^{n}$ as follows

$$A_1 m K_2^{m-1} N^{n} = A_1 m\left(\frac{N}{K_2}\right)^{n} \qquad [\text{as } m + n = 1] \quad ---- \quad (iv)$$

Further from (g) we have

$$K_2 = \left(\frac{Q}{A_1 N^n}\right)^{1/m} \quad + \quad K_2{}^n = \left(\frac{Q}{A_1 N^n}\right)^{n/m}$$

Substituting the value of K_2 above into (iv) we get

$$A_1 m K_2{}^{m-1} N^n = A_1 m \frac{N^n}{Q^{n/m}} A_1{}^{n/m} N^{n^2/m}$$

$$= A_1{}^{m+n/m} m \frac{N^{n/m}}{Q^{n/m}}$$

$$= A_1{}^{m+n/m} m \left(\frac{N}{Q}\right)^{n/m}$$

Thus (iii) can be rewritten as

$$e^{-it}(\dot{P} - iP) + \dot{\lambda}_1 + \lambda_1(t) A_1{}^{m+n/m} m\left(\frac{N}{Q}\right)^{n/m} = 0$$

or $\quad e^{-it}(\dot{P} - iP) + \dot{\lambda}_1 + \lambda_1(t)\,\mu = 0 \quad$ where $\mu = A_1{}^{m+n/m} m \left(\frac{N}{Q}\right)^{n/m}$

or $\quad e^{-it}(\dot{P} - iP) + \lambda_1(t)\mu + \dot{\lambda}_1 = 0$

The above is a differential equation in λ_1 and P and can be solved for λ_1 as follows:

$$\lambda_1 = e^{-\mu t} \int e^{\mu t}[-e^{-it}(\dot{P} - iP)]dt$$

We assume that

$$P = P_o e^{\mu t}$$

therefore

$$\lambda_1 = -e^{-\mu t}\int e^{(\mu-i)t}[aP_0e^{at} - iP_0e^{at}]dt$$

or

$$\lambda_1(t) = \frac{-e^{-\mu t}[aP_0 - iP_0]e^{[a+\mu-i]t}}{(a+\mu-i)} + ge^{-\mu t}$$

where 'g' is the constant of integration

$$= \frac{-e^{-it}[a - i]P}{(a+\mu-i)} + ge^{-\mu t} \quad \text{------------------} \quad (v)$$

Substituting the value of $\lambda_1(t)$ from (v) into (a) we get

$$\lambda_2(t) = -e^{-it}P - \lambda_1(t)$$

$$= -e^{-it}P + \frac{e^{-it}(a-i)P}{(a+\mu-i)} - ge^{-\mu t}$$

$$= \frac{-ae^{-it}P - \mu e^{-it}P + ie^{-it}P + ae^{-it}P - ie^{-it}P}{(a+\mu-i)} - ge^{-\mu t}$$

$$= \frac{-\mu e^{-it}P - ge^{-\mu t}(a+\mu-i)}{(a+\mu-i)} \quad \text{------------------} \quad (vi)$$

Substituting the value of $\lambda_2(t)$ from (vi) into (c) we get an expression for D

$$-e^{-it}C_D + \frac{\{\mu e^{-it}P + Ce^{-\mu t}(a+\mu-i)\}}{(a+\mu-i)}\delta K_1{}^{\gamma}D^{\delta-1} = 0$$

or

$$D = \left\{\frac{e^{-it}C_D(a+\mu-i)}{\delta K_1{}^{\gamma}[\mu e^{-it}P + Ce^{-\mu t}(a+\mu-i)]}\right\}^{1/\delta-1} \quad \text{------------} \quad (vii)$$

Substituting the value of λ_1 from (v) into (d) we get

$$-e^{-it}C_N - \left\{\frac{e^{-it}(a-i)P}{(a+\mu-i)} + ge^{-\mu t}\right\} nA_1K_2{}^m N^{n-1} = 0$$

or

$$N = \left\{\frac{e^{-it}C_N(a+\mu-i)}{nA_1K_2{}^m[e^{-it}(a-i)P - ge^{-\mu t}(a+\mu-i)]}\right\}^{1/(n-1)} \qquad \text{(viii)}$$

Substituting the value of N from (viii) into equation (g) we get

$$Q = A_1K_2{}^m \left(\frac{e^{-it}C_N(a+\mu-i)}{nA\,K^m(e^{-it}(a-i)P - g_e{}^{-\mu t}(a+\mu-i))}\right)^{n/(n-1)} \quad - - - - \text{(ix)}$$

Now substituting the value of $\lambda_2(t)$ and D into (f) we obtain the following:

$$\dot{\lambda}_3(t) = \left\{\frac{-\mu e^{-it}P - Ce^{-\mu t}(a+\mu-i)}{(a+\mu-i)}\right\}\gamma K_1{}^{\gamma-1}K_1{}^{-\gamma\delta/(\delta-1)}\left\{\frac{e^{-it}C_D(a+\mu-i)}{\delta(\mu e^{-it}p+ge^{-\mu t}(a+\mu-i))}\right\}^{\delta/(\delta-1)}$$

$$= \left(\frac{\gamma}{g^{\delta/\delta-1}}\right)(e^{-it}C_D)^{\delta/\delta-1}(a+\mu-i)^{1/(\delta-1)}(\mu e^{-it}P + ge^{-\mu t}(a+\mu-i))^{-1/(\delta-1)}$$

$$- - - - - \text{(x)}$$

The above integral (x) is of the form

$\int(C_1e^{jt} + C_2e^{kt})^{\varepsilon_0}\,dt$ and is difficult to solve. In order to solve it, we assume that $g=0$ in (x) and such that $\dot{\lambda}_3(t)$ is

$$\dot{\lambda}_3(t) = \frac{-\mu^{-1/\delta-1}(a+\mu-i)^{1/(\delta-1)}}{\delta^{\delta/\delta-1}} \gamma\int P^{-1/(\delta-1)} C_D^{\delta/(\delta-1)} dt$$

or

$$\dot{\lambda}_3(t) = \frac{-\mu^{-1/(\delta-1)}(a+\mu-i)^{1/(\delta-1)}}{\delta^{\delta/(\delta-1)}} \gamma\int (P_0 e^{at})^{-1/(\delta-1)} (C_D e^{bt})^{\delta/(\delta-1)} dt$$

Assuming that $P_t = P_0 e^{at}$

$C_t = C_0 e^{bt}$, we have

$$\lambda_3(t) = \frac{-\mu^{-1/(\delta-1)}(a+\mu-i)^{1/(\delta-1)}}{\delta^{\delta/(\delta-1)}} \gamma\left\{\frac{P_0^{-1/(\delta-1)} C_{D_0}^{\delta/(\delta-1)} e^{(\frac{-a}{\delta-1} + \frac{b\delta}{\delta-1})t}}{(\frac{-a}{\delta-1} + \frac{b\delta}{\delta-1})} + g^1\right\}$$

or

$$\lambda_3(t) = \frac{-\mu^{-1/(\delta-1)}(a+\mu-i)^{1/(\delta-1)}}{\delta^{\delta/(\delta-1)}} \frac{\gamma P^{-1/(\delta-1)} C_D^{\delta/(\delta-1)}}{(\frac{-a}{\delta-1} + \frac{b\delta}{\delta-1})} \quad ------ (xi)$$

Finally, substituting the value of $\lambda_3(t)$ from (xi) into (b) we obtain

$$-e^{-it} C_E + \frac{\mu^{-1/(\delta-1)}(a+\mu-i)^{1/(\delta-1)}}{\delta^{\delta/(\delta-1)}} \gamma\left\{\frac{P^{-1/(\delta-1)} C_D^{\delta/(\delta-1)}}{\frac{a}{\delta-1} \; \frac{b\delta}{\delta-1}}\right\} \alpha E^{\alpha-1} = 0$$

or

$$E = \left\{\frac{e^{-it} C_E (\frac{-a\delta^{\delta/(\delta-1)}}{\delta-1} + \frac{b\,\delta^{2\delta/(\delta-1)}}{\delta-1})}{\gamma\mu^{-1/(\delta-1)}(a+\mu-i)^{1/(\delta-1)} P^{-1/(\delta-1)} C_D^{\delta/(\delta-1)}}\right\}^{1/(\alpha-1)} \quad ------ (xii)$$

ESTIMATING EQUATIONS

for $g \neq 0$ (where g = constant of integration)

$$D = \left\{\frac{e^{-it}C_D(a+\mu-i)}{\delta K_1 \gamma(\mu e^{-it}P + ge^{-\mu t}(a+\mu-i))}\right\}^{1/\delta-1}$$

Taking logarithims on both sides we have

$$\text{Log } D = \frac{1}{\delta-1}\log(e^{-it}) + \frac{1}{\delta-1}\log C_D + \frac{1}{\delta-1}\log(a+\mu-i)$$

$$- \frac{1}{\delta-1}\log\delta - \frac{\gamma}{\delta-1}\log K_1 - \frac{1}{\delta-1}\log\{(\mu e^{-it}P + ge^{-it}(a+\mu-i))\}$$

Simplifying $\log \mu e^{-it}P + (e^{-\mu t}(a+\mu-i))\}$ as follows

$$= \log ge^{-\mu t}(a+\mu-i)\{1 + \frac{\mu e^{-it}P}{ge^{-\mu t}(a+\mu-i)}\}$$

$$= \text{Log } g + \log e^{-\mu t} + \log(a+\mu-i) + \log\{1 + \frac{\mu e^{-it}P}{ge^{-\mu t}(a+\mu-i)}\}$$

Using Taylor series expansion we get

$$\log g + \log e^{-\mu t} + \log(a+\mu-i) + \frac{\mu e^{-it}P}{e^{-\mu t}(a+\mu-i)}$$

Substituting the above expression in the equation for D we obtain

$$\log D = \frac{1}{\delta-1}\log(e^{-it}) + \frac{1}{\delta-1}\log C_D + \frac{1}{\delta-1}\log(a+\mu-i)$$

$$- \frac{1}{\delta-1}\log\delta - \frac{\gamma}{\delta-1}\log K_1 - \frac{1}{\delta-1}\log C - \frac{1}{\delta-1}\log(e^{-\mu t})$$

$$- \frac{1}{\delta-1}\log(a+\mu-i) + \frac{1}{g(\delta-1)}\frac{\mu e^{-it_p}}{e^{-\mu t}(a+\mu-i)}$$

$$= -\frac{1}{\delta-1}(\log\delta - \log g) + \frac{1}{\delta-1}(\log C_D - it + \mu t)$$

$$- \frac{\gamma}{\delta-1}\log K_1 + \frac{1}{g(\delta-1)}\frac{\mu e^{-it_p}}{e^{-\mu t}(a+\mu-i)} \quad \text{-----------} \quad (i')$$

$$Q = A_1^{-1/(n-1)} K_2^{-m/(n-1)} \left\{\frac{e^{-it}C_N(a+\mu-i)}{n(e^{-it}(a-i)P - ge^{-\mu t}(a+\mu-i)}\right\}^{n/n-1}$$

$$\log Q = -\frac{1}{n-1}\log A_1 - \frac{m}{n-1}\log K_2 + \frac{n}{n-1}\log e^{-it}$$

$$+ \frac{n}{n-1}\log C_N + \frac{n}{n-1}\log(a+\mu-i) - \frac{n}{n-1}\log n$$

$$- \frac{n}{n-1}\log(ge^{-\mu t}(a+\mu-i))\ \frac{(1 + e^{-it}(a-i)P)}{ge^{-\mu t}(a+\mu-i)}$$

$$= -\frac{1}{n-1}\log A_1 - \frac{n}{n-1}\log n + \frac{n}{n-1}\log C_N - \frac{m}{n-1}\log K_2$$

$$+ \frac{n}{n-1}\log e^{-it} + \frac{n}{n-1}\log(a+\mu-i) - \frac{n}{n-1}\log g - \frac{n}{n-1}\log e^{-\mu t}$$

$$- \frac{n}{n-1}\log(a+\mu-i) - \frac{n}{g(n-1)}\frac{e^{-it}(a-i)P}{e^{-\mu t}(a+\mu-i)}$$

$$= -\frac{1}{n-1}(\log A_1 + \log n + \log C) + \frac{n}{n-1}\log C_N$$

$$- \frac{m}{n-1}\log K_2 - \frac{n}{n-1}(it) + \frac{n}{n-1}(\mu t) - \frac{n}{g(n-1)}\frac{e^{-it}(a-i)P}{(a+\mu-i)}$$

$$= -\frac{1}{n-1}(\log A_1 + \log n + \log C) + \frac{n}{n-1}(\log C_N - it + \mu t)$$

$$- \frac{m}{n-1}\log K_2 - \frac{n}{(n-1)}\frac{e^{-it}(a-i)P}{e^{-\mu t}(a+\mu-i)} \quad \text{- - - - - - - - - - - - (ii')}$$

for $g = 0$ (where g = constant of integration)

$$D = \left[\frac{e^{-it}C_D(a+\mu-i)}{\delta K_1^{\gamma}(\mu e^{-it}P)}\right]^{1/(\delta-1)}$$

Taking logarithms on both sides we get

$$\text{Log } D = \frac{1}{\delta-1}\log C_D + \frac{1}{\delta-1}\log(a+\mu-i) - \frac{1}{\delta-1}\log - \frac{\gamma}{\delta-1}\log K_1$$

$$- \frac{1}{\delta-1}\log\mu - \frac{1}{\delta-1}\log P$$

$$\text{Log } D = -\frac{1}{\delta-1}\log\delta + \frac{1}{\delta-1}\log C_D + \frac{1}{\delta-1}\log\left(a\left(1+\frac{\mu-i}{a}\right)\right)$$

$$- \frac{\gamma}{\delta-1}\log K_1 - \frac{1}{\delta-1}\log\mu - \frac{1}{\delta-1}\log P$$

$$= -\frac{1}{\delta-1}(\log\delta - \log a) + \frac{1}{\delta-1}(\log C_D - \log\mu)$$

$$+ \frac{1}{a(\delta-1)}(\mu-i) - \frac{\gamma}{\delta-1}\log K_1 - \frac{1}{\delta-1}\log P \quad \text{- - - - - - - (iii')}$$

$$Q = A_1^{-1/n-1} K_2^{-m/(n-1)} \frac{e^{-it} C_N (a+\mu-i)}{n(e^{-it}(a-i)P)}^{n/(n-1)}$$

or

$$\text{Log } Q = -\frac{1}{n-1} \log A_1 - \frac{m}{n-1} \log K_2 + \frac{n}{n-1} \log C_N$$

$$+ \frac{n}{n-1} \log (a+\mu-i) - \frac{1}{n-1} \log n - \frac{n}{n-1} \log (a-i) - \frac{n}{n-1} \log P$$

or

$$\text{Log } Q = -\frac{1}{n-1}(\log A_1 + \log n) + \frac{n}{n-1}(\log C_N + \log (a+\mu-i) - \log (a-i))$$

$$- \frac{m}{n-1} \log K_2 - \frac{n}{n-1} \log P \text{ - - - - - - - - - - - - - - - } (iv')$$

$$E = \left\{ \frac{e^{-it} C_E \left(\frac{-a\delta}{\delta-1}^{\delta/(\delta-1)} + \frac{b\delta}{\delta-1}^{2\delta/(\delta-1)} \right.}{\gamma\alpha\mu^{-1/(\delta-1)} (a+\mu-i)^{1/(\delta-1)} P^{-1/(\delta-1)} C_D^{\delta/(\delta-1)}} \right\}^{1/\alpha-1}$$

$$\text{Log } E = \frac{1}{\alpha-1} \log (e^{-it}) + \frac{1}{\alpha-1} \log C_E + \frac{1}{\alpha-1} \log \left(\frac{-a\delta}{\delta-1}^{\delta/\delta-1} + \frac{b\delta}{\delta-1}^{2\delta/\delta-1}\right)$$

$$- \frac{1}{\alpha-1} \log \gamma - \frac{1}{(\delta-1)(\alpha-1)} \log \mu - \frac{1}{(\alpha-1)(\delta-1)} \log (a+\mu-i)$$

$$- \frac{1}{(\alpha-1)(\delta-1)} \log P - \frac{\delta}{(\alpha-1)(\delta-1)} \log C_D - \frac{1}{\alpha-1} \log \alpha$$

$$= -\frac{1}{\alpha-1}\left(\frac{a\delta}{\delta-1}^{\delta/\delta-1} - \frac{b\delta}{\delta-1}^{2\delta/\delta-1} + \log \gamma + \log \alpha \right)$$

$$+ \frac{1}{\alpha-1}(\log C_E^{-it}) - \frac{1}{(\alpha-1)(\delta-1)} (\log \mu + \log (a+\mu-i)$$

$$- \frac{1}{(\alpha-1)(\delta-1)} \log P - \frac{\delta}{(\alpha-1)(\delta-1)} \log C_D \quad \text{- - - - - - - - -} \quad (v')$$

MODIFICATIONS

Note that in equation (iv'), Q is the composite output of oil and gas in BTU terms. To get individual outputs let us consider the left hand side of the CET function,

$$(\beta Q_{oil}{}^{d} + (1-\beta)Q_{gas}{}^{d})^{1/d} = A_1 K_2{}^{m} N^{n}$$

We assume that

$$Q = (\beta Q_{oil}{}^{d} + (1-\beta)Q_{gas}{}^{d})^{1/d}$$

Taking logarithims on both sides of the above equation we get

$$\text{Log } Q = \frac{1}{d} \log (\beta Q_{oil}{}^{d} + (1-\beta)Q_{gas}{}^{d}) \quad \text{- - - - - - - - - -} \quad (vi')$$

Using Taylor Series Expansion[1] we can rewrite (vi') as follows

$$\text{Log } Q = \beta \log Q_{oil} + (1-\beta)\log Q_{gas} - \frac{1}{2} \alpha\beta(1-\beta)$$

$$(\log Q_{oil} - \log Q_{gas})^2 \quad \text{- - - - - - - - - -} \quad (vii')$$

Or

$$\text{Log } Q_{oil} = \frac{1}{\beta} \log Q - \frac{(1-\beta)}{\beta} \log Q_{gas}$$

$$- \frac{1}{2} d3(1-\beta)(\log Q_{oil} - \log Q_{gas})^2 \quad \text{- - - - - -} \quad (viii')$$

Using (iv') and (vii') we obtain expressions for Q_{oil} and Q_{gas}

$$\text{Log } Q_{oil} = -\frac{1}{\beta(n-1)}(\log A_1 + \log n) + \frac{n}{\beta(n-1)}(\log C_N + \log(a+\mu-i)$$

$$-\log(a-i)) - \frac{m}{\beta(n-1)}\log K_2 - \frac{n}{\beta(n-1)}\log P$$

$$-\frac{(1-\beta)}{\beta}\log Q_{gas} + d(1-\beta)(\log Q_{oil} - \log Q_{gas})^2 \quad \text{- (viii')}$$

$$\text{Lo}\hat{\text{g}}\ Q_{gas} = \frac{-1}{(1-\beta)(n-1)}(\log A_1 + \log n) + \frac{n}{(1-\beta)(n-1)}(\log C_N$$

$$+\log(a+\mu-i) - \log(a-i)) - \frac{m}{(1-\beta)(n-1)}\log K_2$$

$$-\frac{n}{(1-\beta)(n-1)}\log P - \frac{\beta}{1-\beta}\log Q_{oil} + d(1-\beta)$$

$$(\log Q_{oil} - \log Q_{gas})^2 \quad \text{------------- (ix')}$$

Note that in all the above estimating equations P is the composite price of oil and gas in BTU terms. To separate this composite price in P_{oil} and P_{gas} we assume that

$$P = P_{oil}^{\phi} P_{gas}^{\psi}$$

Taking logarithims on both sides we get

$$\text{Log } P = \phi \log P_{oil} + \psi \log P_{gas} \quad \text{---------------- (x')}$$

We substite (x') in all the estimating equations to obtain separate coefficients for P_{oil} and P_{gas}.

FOOTNOTES:

1. Kmenta, J. Elements of Econometrics, McMillan Publishing Company, P. 463

Notations of the variables used in the model

The definition of each variable and its method of calculation is given below:

C_E = the effective cost of exploration per foot and is calculated as

$$C_E = AC_E - (\tau)\ (\gamma_E)AC_E - (DE)(\tau)\ AC_E$$

where AC_E is the actual per foot cost of exploratory drilling

τ is the regulated corporate income tax rate

γ_E is the exploration expenditure write off rate

DE is the federal depletion allowance rate.

C_D = the effective cost of development per foot calculated as

$$C_D = AC_D - (\tau)(\gamma_D)AC_D - (DE)(\tau)AC_D$$

where AC_D is the actual per foot cost development drilling

γ_D is the development expenditure write off rate

C_N = the effective cost of operating per '000 BTU of oil and gas. This is calculated as

$$C_N = AC_N\ (\ 1 - (\tau)(1 - RA))$$

where AC_N is the actual cost of operating per '000 BTU of oil and gas

RA is the resource allowance rate.

$\hat{C}_{E+D}$ = the expected cost of exploration and development calculated as

$$.7C(E+D)_t + .3C(E+D)_{t-1}$$

D = total development footage drilled in time period t

DE = the depletion allowance rate

E = total exploratory footage drilled in time period t

EXP = expected profitability in time period t measured by the bonus bids paid per acre in time period t.

i = interest rate

K_1 = level of probable reserves

K_2 = level of proved reserves

L = total number of acres acquired for exploration through licenses and leases.

MDP = market demand prorationing in period t and calculated as excess capacity i.e. a ratio of the productive capacity to actual production.

N = amount of variable inputs used in period t for field i.

P = composite price of oil and gas measured in terms of per '000 BTU, and weighted by production proportions in that year.

P_{gas} = netback price of gas per '00 Mcf in time period t and is calculated as

$$P_{gas} = AP_{gas} - (R_g)\ AP_{gas}$$

where AP_{gas} is the wellhead price of gas per '00 Mcf

R_g is the average royalty rate on gas.

$\hat{P}_{gas}$ = Expected price of gas where it is calculated as

$$.7P_{gas} + .3P_{gas\ t-1}$$

P_{oil} = netback price of oil per barrel in period t and is calculated as

$$P_{oil} = AP_{oil} - (R_O)\ AP_{oil}$$

where AP_{oil} is the wellhead per barrel price of oil per barrel and R_O is the average rate of royalty for oil in the same year.

$\hat{P}_{oil}$ = Expected price of oil calculated as

$$.7P_{oil\,t} + .3P_{oil\,t-1}$$

Q = Composite output of oil and gas produced in t measured in '000 of BTU

Q_{gas} = total output of gas measured in '000 of cubic metres per year

Q_{oil} = total output of oil measured in cubic metres per year

RA = the federal resource allowance rate.

RE = change in after tax retained earnings of the oil and gas industry.

R_q = the average royalty rate on gas

R_O = the average royalty rate on oil

RP_{alt} = Rate of return on capital in alternative industries. This is calcualted on the basis of seven industry groups which are total mining, primary metals, metal fabrication, non metalic mineral products, petroleum and coal products, chemical products and public utilities.

RP_{oil} = wellhead price of oil in Alberta relative to that in the U.S.

SU_E = success ratio where success ratio is defined as probable reserves found per foot of exploratory drilling.

$\hat{SU}_E$ = the expected success ratio in exploration calculated as

$$\hat{SU}_E = .7SU_{Et} + .3SU_{E\,t-1}$$

T = life of reservoir

UDR_t = level of undiscovered reserves at the beginning of period t.

τ_F = the actual federal corporate income tax rate

τ_P = the actual provincial corporate income tax rate

Y_E = the exploratory expenditure write off rate

γ_D = the development expenditure writeoff rate

μ = the productibility of the variable (labor) input in the production phase.

APPENDIX C: EXHIBITS

1) Company Name: ....

2) Major Areas of Operation: a) Foothills b) Plains c) Central d) Northern

(NOTE: THE FOLLOWING QUESTIONS CORRESPOND TO THE AREA YOU HAVE SPECIFIED IN (2)).

3) Footage Covered:

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
a) Exploratory															
b) Development															
1)oil															
2)gas															

4) No. of Wells Drilled:

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
a) Exploratory															
b) Development															
1)oil															
2)gas															

5) Average Well Depth:

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
1)oil															
2)gas															

7) Expenditures: (In thousands of dollars)

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
a) Permit fees & acquisition costs-include bonuses, legal fees & filing fees.															
b) Non-producing acreage retention costs, including land department salaries & over-head.															
c) Producing lease & surface rentals.															
iv) Exploratory drilling															
v) Development drilling															
vi) Tangible well & lease equipment															
vii) Pipe lines & related facilities															
viii) Secondary recovery & pressure maintenance project															
ix) Natural gas processing plants															

6) Reserves found:

(NOTE: BOTH PROBABLE AND PROVED RESERVES RELATE TO THE YEAR THE WELL WAS DRILLED)

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
a) Probable															
1) oil															
2) gas															
b) Proved															
1) oil															
2) gas															

7) Expenditures: (In thousands of dollars)

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
i) Geological & geophysical															
a) Seismic crew expenses															
b) All other geological & geophysical expenses															
ii) Area covered by geological & geophysical survey															
iii) Land & lease acquisition & retention excluding inter-company sales on transfers															

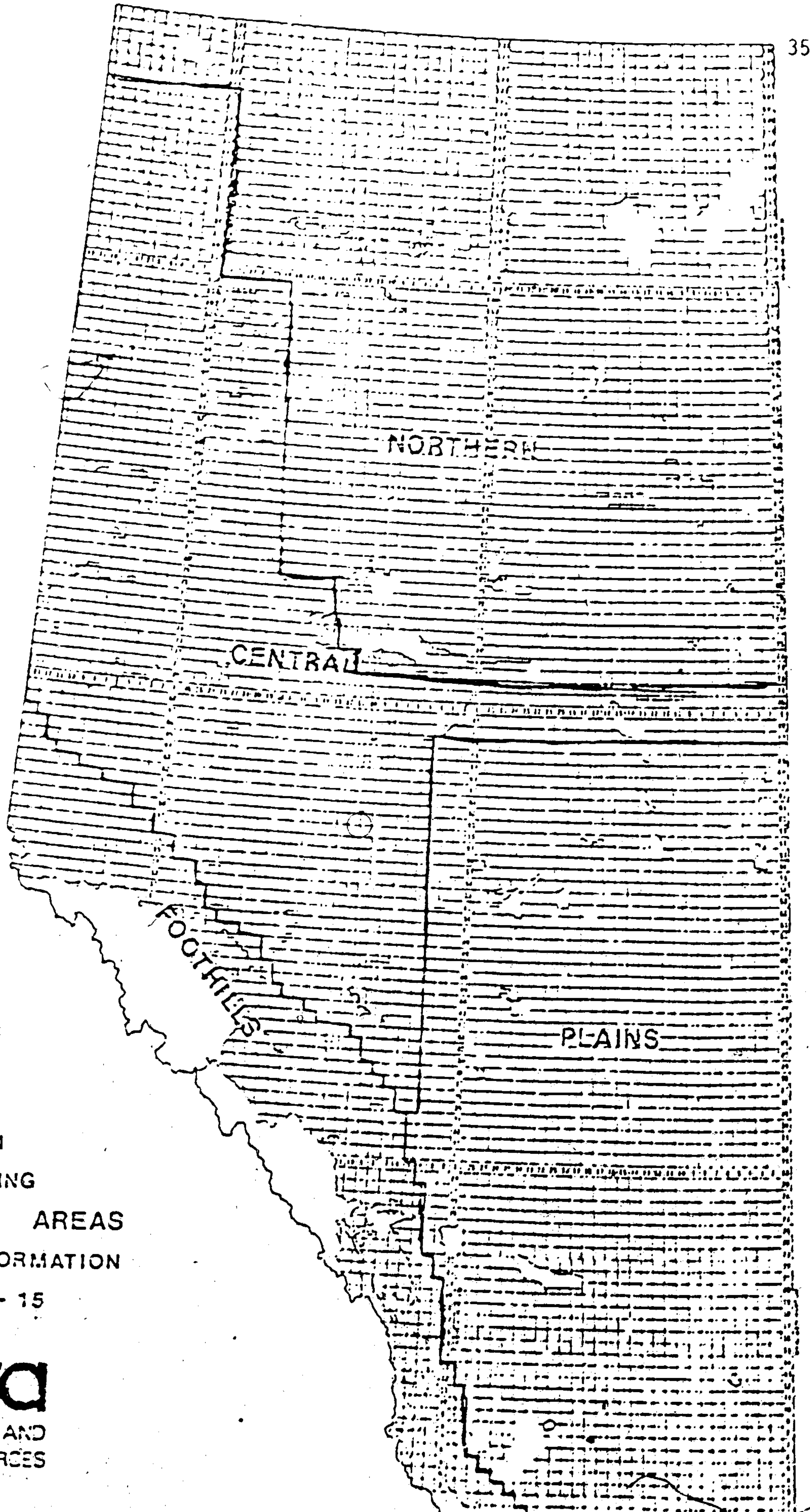


FIGURE 1

MAP SHOWING

DRILLING CREDIT AREAS

ATTACHMENT TO INFORMATION

LETTER NO. 77-15

Alberta

ENERGY AND

NATURAL RESOURCES

DECEMBER, 1977

RESUME

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DATE OF BIRTH:	July 16, 1955
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WORK EXPERIENCE:

July 1983 - Present

Working as a Policy Analyst with the Saskatchewan Department of Energy and Mines. The job involves:

- general policy analysis in minerals sector including oil, gas, uranium and potash with special emphasis on taxation and supply side economics;
- econometric including supply, demand and revenue models in the mineral sectors. Emphasis is on utilization of the existing models or formulation of new models to obtain quantitative response to changing policy environment;
- project analysis of major provincial projects with emphasis on possible macroeconomic impact utilizing both Canadian and Provincial macroeconomic models.

September 1985 - Present

- part-time instructor in economics.

May 1983 - June 1983

Worked as summer research student with the Alberta Department of Housing. The job involved formulating an econometric model for the housing industry to forecast housing starts in the Province of Alberta.

September 1982 - April 1983

Worked as a Teaching/Research Assistant at the University of Alberta. The job was to assist in data collection and coordination as was as empirical estimation on some of the ongoing projects at the Department of Economics and the Department of Business Administration. Also, assisted in evaluating student course work in Economics and Business Administration.

May 1982 - August 1982

Worked as a Summer Research Student with the Alberta Department of Occupational Health and Safety. The job involved an evaluation of the effects of extended hours in a coal mine on Occupational Safety. A report including a review of existing literature and recommendations was submited to be used later on for instituting changes in the existing legislation on working hours in the coal mines.

May 1982 - April 1982

Worked as a Research Analyst with the Alberta Department Of Energy and Natural Resources. The work involved a project (also my Ph.D. thesis) evaluating the effects of public policy on the supply of crude oil and natural gas in Alberta. The scope of the project included:

- formulation of the mathematical model encompassing the effects of various government regulations, tax regimes and price expectation on the supply of crude oil and natural gas;
- collection of both secondary and primary data on past and present performance of the oil and gas industry;
- forecasting the industry activity under the various tax and policy assumptions.

September 1977 - April 1980

Worked as a Research Teaching Assistant at the University of Alberta, collecting both U.S. and Canadian data for various projects and evaluating student work in International Trade and Macroeconomics.

September 1976 - August 1977

Worked as a Teaching Assistant at the Department of Economics, University of Waterloo.