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Development of Natural Resource Accounts: Physical and Monetary Accounts for Crude Oil and Natural Gas Reserves in Alberta, Canada

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Development of Natural Resource Accounts: Physical and Monetary Accounts for Crude Oil and Natural Gas Reserves in Alberta, Canada

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Development of Natural Resource Accounts:

Physical and Monetary Accounts for Crude Oil and Natural Gas Reserves in Alberta

May, 1992

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The paper presents preliminary results in the programme of the development of Natural Resource Accounts.

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1.0 BACKGROUND

This paper is part of the continuing development work to complete the Canadian System of National Accounts (CSNA). Based largely on the United Nations' System of National Accounts (UN, 1968) and related documents, the CSNA is one of the most complete in the world. Its present components are the Income and Expenditure Accounts, the Input-Output Accounts, Industry Product Measures, the Balance of Payments, the International Investment Position, the Financial Flow Accounts, the National Balance Sheet Accounts and Provincial Economic Accounts.

The National Balance Sheet Accounts divide the economy into 41 sectors and sub-sectors and provide estimates of non-financial assets (the wealth accounts) and financial assets, liabilities and net worth for each sector. The non-financial assets presently include consumer durables, residential structures, non-residential structures, machinery and equipment, and land.

When these estimates were first published in 1985, it was intended that further work be undertaken to complete the balance sheet by including such items as sub-soil mineral stocks, fish stocks and water, etc.

While the United Nation's System of National Accounts made no reference to the inclusion of natural resources, in the Provisional Guidelines (United Nations, 1977) it was proposed that natural resources be included in the national balance sheet. However, there were no recommendations provided on the method or means of doing so. Since then, there has been a rapid rise in environmental concerns, including the issue of resource accounting. Canada's Green Plan (Ottawa, 1990), the United Nation's SNA Handbook (1990) and a variety of work undertaken by countries such as Japan, France, the Netherlands and Norway as well as Indonesia, provide ample evidence of these concerns and responses to them.

In December, 1990, the Federal Government released Canada's Green Plan. As part of its mandate, the current national accounts are to be extended to incorporate environmental components along with Canada participating in international accounting efforts. In order to increase public awareness and information, and improve environmental monitoring, Statistics Canada has implemented pilot accounts for two natural resources: one for a non-renewable resource: oil and gas reserves and one for a renewable resource: forestry. Also, an environmental accounting framework is to be prepared with regular publication of new environmental components in the future.

In this study, Statistics Canada presents the first in a series of papers on approaches to accounting for natural resources in the CSNA. This paper presents measures of Alberta's oil and gas reserves in value as well as volume terms, as the first step to the construction of such estimates for the whole country. Valuation of natural resources is difficult as, by definition, they have not yet entered the production process. To overcome this problem, various imputations are determined to which different methods have been applied to establish a variety of capital values.

Much of the literature on natural resource accounting has concentrated on resource depletion and adjusting GDP. The approach of this research study is to calculate the value of the natural resources so that this value may be included in the national balance sheet in line with the recommendations of the newly proposed UN System of National Accounts. As a result, it is intended that the data will become part of the Canadian National Balance Sheet Accounts (Statistics Canada, Catalogue 13-214). The value data will be shown in different methods of valuation, so users may utilise whichever is most suitable. A reconciliation table of opening balance, depletion, additions, revaluation (value method only) and closing balance will be published. However, there will be **no** attempt to adjust Gross Domestic Product (GDP) in order to provide some measure of a "Green GDP" or "Green Net Domestic Product". The **core** accounts of the Canadian System of National Accounts will include natural resources in the balance sheet only. Further work on environment accounting will be developed in a related, but separate, Environment Satellite Account.

In view of the developmental nature of this paper, readers are encouraged to respond.

2.0 INTRODUCTION

The goal of this project is to develop both physical and monetary accounts for crude oil and natural gas reserves in Canada. These accounts are developed within the framework of the CSNA and follow CSNA accounting procedures. While the physical accounts are reported in units of reserves, several methods of valuation for the monetary accounts are presented.

Economically workable sub-soil mineral deposits are wealth assets and not merely "free gifts of nature" as they are currently treated by conventional methods of national accounting (Ward, 1982). Thus, there is no accounting for the total value of Canada's natural resources or their depletion.

Ward (1982) suggests that national accounting methods should be modified to distinguish between that part of value added of the mineral sector which is part of *income* and that part which is part of national *wealth*.

The increased national and global consciousness of the impacts of economic activities on the natural environment has created the need to develop an integrated environmental and economic accounting framework (UN SNA Handbook, 1990). This framework should be linked with the strategies of sustainable development which balance the human needs with a stable natural environment. The proposed revised system of national accounts would contain reconciliation accounts and detailed description of assets of the natural environment including sub-soil assets.

Natural resource accounts can be used to monitor the natural environment. These accounts measure the short-term exploitation of the natural environment as well as the aspect of sustaining the natural environment for future generations.

Much of the focus of the literature on natural resource accounting has been on the depletion of natural resources and how national income numbers (namely GDP and NDP) should incorporate this loss (Ward (1982), Hartwick (1988, 1989, 1990a, b, 1991), Repetto et al (1989), El Serafy (1989) and Devarajan and Weiner (1990)). The focus of this project is to develop a set of accounts for the National Balance Sheet and also Reconciliation Accounts which values the total oil and gas reserves in Canada from 1961 to 1989. This involves examining the appreciation (reserve additions) and the depreciation (reserve extraction) of remaining reserves from year to year and incorporating these changes into the national accounts. Several methods of monetary valuation for oil and gas reserves in the United States have been proposed in the literature (Soloday (1980), Ferran (1981), Landefeld and Hines (1985), Boskin et al (1985) and Miller and Upton (1985 a, b)) and are examined here.

This paper presents the results for the Province of Alberta which is the largest producer of oil and natural gas in Canada. The value of Alberta's production for conventional crude oil, natural gas and its associated by-products was $13.5 billion in 1989 or 84 per cent of Canada's total of petroleum production (Statistics Canada, The Crude Petroleum and Natural Gas Industry, Catalogue 26-213). The value of Alberta's production from non-conventional sources was $2.2 billion, representing all of Canada's synthetic crude oil production in that year. Table 1 presents the value of production of crude oil, natural gas and by-products in Alberta for 1961-1989.

Table 1: Value of Marketable Production in the Crude Oil and Natural Gas Industry in Alberta (millions of dollars)

Year	Crude Oil & Condensate	Synthetic Crude Oil	Natural Gas	Natural Gas Liquids	Sulphur	Total Value	Total Value Canada
1961	380.0	0.0	50.9	15.3	6.1	452.3	608.8
1962	388.5	0.0	78.9	29.4	8.3	505.1	707.8
1963	424.8	0.0	96.6	58.5	12.1	592.0	818.5
1964	450.3	0.0	113.2	72.1	16.8	652.4	903.6
1965	472.3	0.0	122.5	85.4	24.1	704.3	978.1
1966	522.7	0.0	135.5	96.5	37.2	791.9	1092.5
1967	588.8	1.2	150.6	106.3	65.0	911.8	1230.9
1968	644.7	15.7	171.0	119.1	76.3	1026.8	1376.0
1969	712.6	27.8	200.4	131.9	58.9	1131.6	1478.3
1970	844.1	33.3	243.9	155.8	27.4	1304.5	1645.6
1971	1011.8	46.6	266.3	185.0	19.3	1529.0	1898.7
1972	1210.5	62.3	307.3	243.9	17.7	1841.7	2224.9
1973	1821.9	72.2	359.0	339.4	39.9	2632.4	3051.9
1974	2875.6	108.8	604.2	634.5	93.5	4316.6	4945.2
1975	3095.9	123.4	1299.0	755.0	143.9	5417.2	6098.2
1976	3284.0	162.3	2104.5	774.8	110.8	6436.2	7400.3
1977	3897.3	207.7	2878.3	940.6	100.2	8024.1	9105.8
1978	4606.1	297.5	3281.0	1040.9	107.1	9332.6	10566.2
1979	5694.7	792.1	4096.1	1406.3	154.7	12143.9	13543.5
1980	6177.7	1716.6	5369.7	1802.8	334.4	15401.1	16860.8
1981	6755.3	1548.4	5520.7	2063.1	470.0	16357.5	17961.6
1982	8465.8	2072.5	6234.4	2258.5	434.8	19466.0	21593.2
1983	11089.8	2625.8	5958.3	2617.7	351.4	22643.1	25555.5
1984	12601.9	2385.3	6688.0	2777.9	386.2	24839.2	28308.1
1985	12400.8	2806.5	6680.6	2740.3	683.0	25311.4	29270.1
1986	6255.3	1710.0	5048.9	1756.5	683.2	15453.9	17760.7
1987	7834.5	2203.5	4021.7	1821.3	473.4	16354.5	19126.2
1988	6014.6	1696.1	4584.5	1542.3	426.8	14264.4	16413.2
1989	6894.1	2161.1	4624.7	1570.2	366.9	15617.1	18265.8
1990	8023.2	2799.3	4841.6	2297.6	301.9	18263.5	21481.1

[1] 1961-1972 data represent the value of producers' sales; 1972-1989 data represent the value of marketable production; differences between the two series are assumed to be minor

Source: Statistics Canada, The Crude Petroleum and Natural Gas Industry, Catalogue 26-213; and Canadian Petroleum Association Statistical Yearbook

At the end of 1989, there were 582.2 million cubic metres of conventional crude oil reserves in Alberta, representing 62 per cent of Canada's remaining established[1] conventional crude oil reserves, 1.7 billion cubic metres of marketable natural gas reserves (62 per cent of the Canadian total) and 326 million cubic metres of developed synthetic crude oil (100 per cent of the Canadian total). The upstream oil and natural gas sector is a capital-intensive activity.

Capital (namely exploration and development) expenditures in Alberta have increased from $272 million in 1961 to $3.6 billion in 1989. Net fixed capital stock estimates for the sector have increased from $1.6 billion to $38.3 billion in that same period. Royalties and land acquisition costs and rental fees totalled $154 million in 1961 and $3.1 billion in 1989 for the province.

Since most of Canada's petroleum production and remaining reserves are located in Alberta, most of the analysis of Canada's petroleum industry has focussed on Alberta. These analyses are a good source of data for the development of physical and monetary accounts for Canada's oil and natural gas reserves. Valuation models developed for Alberta's conventional reserves of crude oil and natural gas will be extended to other areas of Canada with oil and natural gas reserves and Alberta's non-conventional crude oil reserves.

The next section describes the definition of reserves used in the development of the physical accounts and Section 4 presents the physical accounts for the crude oil, natural gas reserves and their by-products in Alberta. In Section 5, the concept of economic rent which is central to the monetary valuation of natural resources is defined. In Sections 6 to 10, we present a theoretical discussion of the different methods of monetary and accounting valuation, economic depreciation, the measurement of resource scarcity, the treatment of the return to man-made capital and the discount rate. Section 11 presents the current treatment of natural resource revenues and expenditures in the CSNA and the proposed treatment of these components in the monetary valuation of reserves. The results from three different methods of monetary valuation are presented in Section 12 and reconciliation tables are shown in Section 13.

1. See next section for a more complete definition.

3.0 THE DEFINITION OF MINERAL RESERVES AND RESOURCES

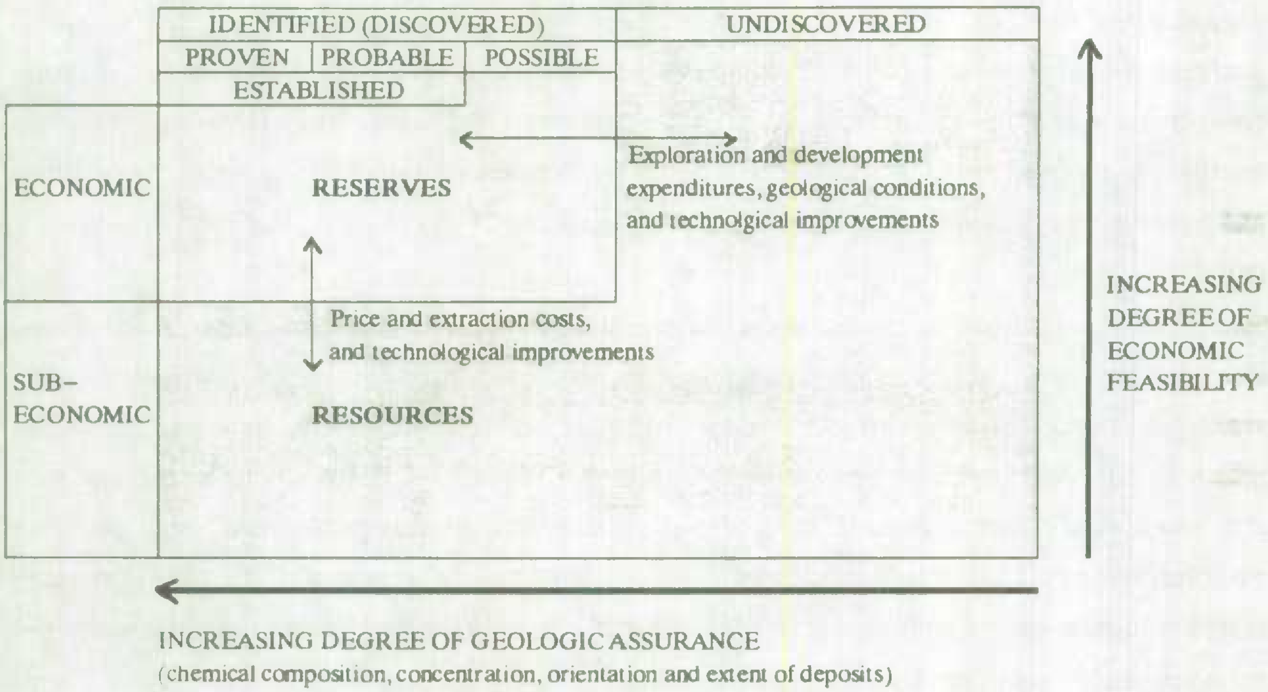
The McKelvey Box (Figure 1; McKelvey, 1972) illustrates the classification of mineral reserves and resources. The vertical axis represents the degree of economic recovery and the horizontal axis measures the degree of geologic certainty of mineral reserves and resources. The boundary between identified (discovered) and undiscovered resources fluctuates as the result of a mining company's investment in exploration and development, and differing geological conditions (Crowson, 1982). The boundary between economic reserves and sub-economic resources is affected by the relationship between prices and extraction costs, and technological improvements. Identified resources are defined as discovered reserves in producing areas. Undiscovered resources are in non-producing areas or in non-productive strata in producing areas. The definition of reserves used in this project is *remaining established reserves* which are identified as recoverable, proved and probable reserves in the McKelvey Box.

The diagram also illustrates the difference between economic and geologic exhaustion. An oil field is generally economically exhausted before it is geologically exhausted (Brobst, 1979). Primary recovery methods generally obtain about 30 per cent of the crude oil in the ground (60 to 90 per cent for natural gas in Alberta). Enhanced ("secondary and tertiary") recovery methods are also employed to increase these recovery rates. The definition of reserves used in this project incorporates primary and enhanced recovery rates in its physical values.

3.1 Definition of Crude Oil and Natural Gas Reserves

Oil and natural gas reserve estimates in Canada provided by the Canadian Petroleum Association (CPA), Alberta Energy Resources Conservation Board (AERCB), National Energy Board (NEB) and other government agencies are reported as ***established*** reserves. Established reserves are "those reserves recoverable under current technological and present and ***anticipated*** economic conditions, specifically proved by drilling, testing or production, plus that judgement portion of contiguous recoverable reserves that are interpreted to exist from geological, geophysical or similar information, with reasonable certainty" (Tanner, 1986, p. 22). For the development of natural resource accounts, we are concerned with remaining established reserves, extraction of reserves and their appreciation as the result of discoveries, development, revisions and enhanced oil recovery (secondary and tertiary recovery).

Figure 1. The Mckelvey Box used to distinguish reserves from resources.



Source: modified after McKelvey (1972)

In the definition outlined in the United Nation's SNA Handbook (1990), it is proposed that subsoil assets comprise **proven** reserves: "to meet normally three criteria: high probability of existence (95 per cent), exploitability with existing techniques and positive net return (i.e. market price exceeds exploitation costs)" (p. 140). Proven reserves of petroleum are "the estimated quantities... which analysis of geological and engineering data demonstrate, with reasonable certainty in the future from known reservoirs under the economic and operational conditions...proved developed reserves are those proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods" (U.N. SNA Handbook, 1990).

The distinction between developed and undeveloped reserves is not made in established reserves. "Proven developed" reserves are proved reserves estimated to be recoverable through existing wells. "Proved undeveloped" reserves are proved reserves estimated to exist in proved reservoirs which will be recovered from wells drilled in the future (Schanz, 1975). In this project it is assumed that established reserves include both developed and undeveloped proven and some probable reserves, and exploration and development expenditures will be allocated to the total remaining established reserves. The rationale for this decision is mainly because of data limitations and the relatively conservative definition of reserves used.

The definition of established reserves allows for advances in current technology and a reasonable forecast of economic conditions. Tanner (1986) suggests that the definition of proven reserves is too conservative for macro-economic planning and that established reserves reflect what reserves will be available for national production and consumption.

Since the data sources used in this study report established reserves, this convention will be used. In 1978, government agencies reporting oil and gas statistics shifted to the established reserves definition. Prior to 1978, reserve estimates were reported as proven or as probable. Although established reserve estimates are provided by the CPA and the AERCB prior to 1978, there are minor breaks in the series.

3.2 Natural Gas Reserves: Data Limitations

Measurement of reserves is an imprecise science at the best of times, with frequent revisions in recoverability during a well's life. The exact size of the economic resource is known only when the well has ceased to produce. In addition, there are problems in separating the various types of resources that are extracted. This is especially true for natural gas and its by-products.

At the end of 1989, some 17 per cent of the remaining reserves of marketable natural gas occurred as "associated" or as "solution natural gas". Non-associated gas occurs in a natural reservoir not in contact with crude oil, while associated gas is in contact with crude oil and solution gas is dissolved in the crude oil at reservoir conditions.

McLachlan (1990) recognizes that some of the costs should be allocated to the associated and solution gas found with crude oil. This implies that costs associated with natural gas are underestimated. This is probably more relevant to exploratory intent than development intent where development costs are better subdivided into natural gas and crude oil costs. McLachlan does not make any adjustments to account for solution and association natural gas in his study.

Eglington and Uffelmann (1983) also include reserves of associated gas with non-associated gas without assigning any portion of oil exploration and development expenditures to natural gas. For the period in their study (1957-1979), it was not believed that this approach would significantly affect the results.

In order to account for the fact that natural gas occurs in crude oil discoveries as well as the greater risks inherent in crude oil exploration relative to natural gas, Pasay (1987) calculates separate finding costs with the crude oil exploration "intent" increased by an arbitrary 25 per cent at the expense of natural gas exploration intent.[2] Proxies for exploration intent and development intent are calculated using only successful metres drilled. There is an implicit assumption that the same portion of unsuccessful metres drilled are attributable to crude oil and natural gas.

2. This approach appears to be the opposite to the argument presented by McLachlan (1990).

In this project no allowances have been made for associated and solution natural gas in the allocation of exploration, development and operating costs because of the methodology used by others and expenditure data limitations.

4.0 PHYSICAL ACCOUNTS

Estimates of established reserves of crude oil and natural gas and their by-products for the Province of Alberta are provided by the AERCB and the CPA (Tables 2-10). Figures 2 and 3 are comparisons of conventional oil and natural gas reserves reported by the AERCB and the CPA.

Tanner (1986) presents an overview of the reserve data from these two sources and reviews the differences. During the period from 1962 to 1982, the CPA estimates were as much as 200 million cubic metres higher that the AERCB estimates. The differences in estimates between the CPA and AERCB are due in part to the CPA booking reserves expected to be recovered from enhanced oil recovery (EOR) methods at an earlier time than the AERCB.

In 1964, the large increase in booked reserves by both the CPA and AERCB was caused by the introduction of a reserves-based prorationing system in Alberta where the number of established reserves for each producing oil pool determined the pool's prorated allowable production. The increase in reserve additions from EOR also corresponds to the beginning of the reserves-based prorationing system.[3] In 1976, EOR additions were negative due to reassessment of the schemes that did not proceed.

3. Under prorationing, the AERCB sets the total of allowable production for the province equal to the estimated market demand as filed by refiners. Changes to the system over time have resulted in changes to the method of allocating the total allowable production among producers. Prior to 1964, prorationing was based on an economic allowance graduated to well depth and productive capacity of each well. After 1964, market demand was allocated across reservoirs in proportion to reserves and not on the number of wells or well productive capacity (Helliwell et al, 1988, pp. 30-31).

Table 2: Remaining Reserves of Conventional Crude Oil in Alberta, Data from the Alberta Energy Resources Conservation Board (million of cubic metres)

Year	Opening Stock	New Discoveries	Development & Revaluation	Development Only	Enhanced Recovery	Total Additions	Depletion	Closing Stock	Net Change
1956	389.3	3.5	78.5		0.0	82.0	22.8	448.4	59.1
1957	448.4	10.8	29.1		0.0	39.9	21.7	466.6	18.2
1958	466.6	1.3	-4.8		4.9	1.4	17.9	450.2	-16.4
1959	450.2	14.3	37.2		16.0	67.5	20.5	497.2	47.0
1960	497.2	0.5	29.9		18.1	48.5	20.7	525.0	27.8
1961	525.0	1.7	31.5		24.5	57.7	25.1	557.6	32.6
1962	557.6	2.9	21.8		19.9	44.6	26.2	575.6	18.0
1963	575.6	14.6	12.6		29.2	56.4	26.8	605.4	29.8
1964	605.4	9.5	88.2		250.8	348.5	27.9	926.7	321.3
1965	926.7	28.6	42.6		-2.4	68.8	29.2	965.7	39.0
1966	965.7	89.1	13.5		38.3	140.9	32.0	1074.2	108.5
1967	1074.2	57.2	15.7		22.2	95.1	36.6	1132.9	58.7
1968	1132.9	62.0	14.8		42.9	119.7	39.8	1212.8	79.9
1969	1212.8	40.5	-44.5		58.5	54.5	44.4	1222.8	10.0
1970	1222.8	8.4	-7.6		36.1	36.9	51.7	1207.9	-14.9
1971	1207.9	14.0	8.7		-0.8	21.9	56.4	1173.6	-34.3
1972	1173.6	10.8	-5.6		14.8	20.0	67.4	1126.0	-47.6
1973	1126.0	5.1	-6.0		10.2	9.3	83.3	1052.0	-74.0
1974	1052.0	4.3	3.3		30.8	38.4	79.0	1011.5	-40.5
1975	1011.5	1.6	2.1		3.3	7.0	67.5	950.9	-60.6
1976	950.9	2.5	5.9		-27.0	-18.6	61.0	871.3	-79.6
1977	871.3	4.8	5.1		9.2	19.1	60.4	830.0	-41.3
1978	830.0	24.9	-1.9		1.4	24.4	60.0	794.5	-35.5
1979	794.5	19.2	10.3		4.8	34.3	68.5	760.2	-34.3
1980	760.2	9.0	5.1		8.6	22.7	63.2	719.9	-40.3
1981	719.9	15.0	7.2		10.4	32.6	56.5	696.0	-23.9
1982	696.0	16.8	-16.5		6.6	6.9	53.6	649.4	-46.6
1983	649.4	21.4	24.8		17.9	64.1	55.0	657.8	8.4
1984	657.8	29.1	-12.0		24.1	41.2	59.2	640.7	-17.1
1985	640.7	32.7	9.7	10.6	21.6	64.0	56.2	648.5	7.8
1986	648.5	28.6	-14.1	16.6	24.6	39.1	53.2	634.7	-13.8
1987	634.7	20.9	1.6	12.8	10.5	33.0	53.9	613.8	-20.9
1988	613.8	17.7	2.5	18.2	16.5	36.7	57.2	592.9	-20.9
1989	592.9	17.0	-3.4	12.9	7.8	21.4	53.8	560.5	-32.4
1990	560.5	25.0	-25.6		3.7	3.0	53.1	510.5	-50.0

Source: Alberta Energy Resources Conservation Board; compiled by National Accounts and Environment Division, Statistics Canada

Table 3: Remaining Established Reserves of Crude Oil in Alberta; Data from the Canadian Petroleum Association (millions of cubic metres)

Year	Opening Stock	Total Additions	Depletion	Closing Stock	Net Change
1962	..	..	26.2	879.4	
1963	879.4	3.7	26.8	856.2	-23.1
1964	856.2	218.5	27.9	1046.8	190.6
1965	1046.8	160.0	29.2	1177.6	130.8
1966	1177.6	182.1	32.2	1327.5	149.9
1967	1327.5	95.3	36.7	1386.2	58.7
1968	1386.2	80.5	40.0	1426.7	40.5
1969	1426.7	61.6	45.5	1442.8	16.1
1970	1442.8	4.2	52.4	1394.6	-48.2
1971	1394.6	37.1	56.8	1374.9	-19.7
1972	1374.9	19.5	67.5	1327.0	-48.0
1973	1327.0	1.7	83.0	1245.7	-81.3
1974	1245.7	-5.4	79.1	1161.2	-84.5
1975	1161.2	-25.0	67.5	1068.7	-92.5
1976	1068.7	4.3	60.9	1012.1	-56.6
1977	1012.1	5.6	60.5	957.2	-54.9
1978	957.2	34.6	60.1	931.6	-25.5
1979	931.6	45.3	68.5	908.4	-23.2
1980	908.4	-65.2	63.2	780.0	-128.4
1981	780.0	-4.2	57.0	718.8	-61.1
1982	718.8	18.1	54.4	682.5	-36.3
1983	682.5	38.1	55.3	665.3	-17.2
1984	665.3	61.0	59.9	666.4	1.1
1985	666.4	39.4	57.0	648.7	-17.6
1986	648.7	37.1	53.1	632.7	-16.0
1987	632.7	53.7	55.2	631.3	-1.4
1988	631.3	37.9	57.6	611.5	-19.8
1989	611.5	23.6	52.6	582.5	-29.0

.. not available

Source: Canadian Petroleum Association Statistical Yearbook

Table 4: Remaining Established Reserves of Marketable Natural Gas in Alberta; Data from the Alberta Energy Resources Conservation Board (billions of cubic metres)

Year	Opening Stock	New Discoveries	Development & Revaluation	Total Additions	Depletion	Closing Stock	Net Change
1957	520.1	–	–	64.9	3.8	581.7	61.6
1958	581.7	–	–	110.4	5.3	686.4	104.7
1959	686.4	–	–	88.5	7.1	767.8	81.4
1960	767.8	18.2	101.7	119.9	9.1	878.6	110.8
1961	878.6	9.6	3.7	13.3	11.9	879.9	1.3
1962	879.9	8.9	41.0	49.9	17.6	912.1	32.2
1963	912.1	3.1	32.7	35.8	19.6	928.2	16.1
1964	928.2	7.2	78.7	85.9	22.1	992.0	63.8
1965	992.0	11.3	78.4	89.7	24.2	1057.6	65.6
1966	1057.6	2.1	38.6	40.7	25.5	1072.6	15.0
1967	1072.6	24.3	49.6	73.9	27.5	1119.1	46.5
1968	1119.1	15.3	119.3	134.6	30.0	1223.6	104.5
1969	1223.6	18.6	68.9	87.5	37.8	1273.4	49.8
1970	1273.4	7.6	38.7	46.3	40.1	1279.4	6.0
1971	1279.4	4.8	40.6	45.4	48.5	1276.3	-3.1
1972	1276.3	12.5	32.8	45.3	52.4	1269.1	-7.2
1973	1269.1	7.8	175.6	183.4	56.0	1396.6	127.5
1974	1396.6	8.6	138.4	147.0	57.0	1486.5	89.9
1975	1486.5	0.8	20.0	20.8	56.6	1450.8	-35.7
1976	1450.8	6.9	98.7	105.6	54.6	1501.7	50.9
1977	1501.7	6.6	120.9	127.5	61.0	1568.3	66.6
1978	1568.3	24.4	138.9	163.3	66.4	1665.2	96.9
1979	1665.2	16.4	106.8	123.2	70.0	1718.4	53.2
1980	1718.4	30.0	62.5	92.5	63.8	1747.0	28.6
1981	1747.0	28.9	88.1	117.0	68.6	1795.3	48.3
1982	1795.3	10.6	108.1	118.7	60.9	1853.1	57.8
1983	1853.1	16.3	22.7	39.0	66.0	1826.2	-26.9
1984	1826.2	9.6	30.9	40.5	68.3	1798.4	-27.8
1985	1798.4	11.5	31.1	42.6	72.8	1768.3	-30.1
1986	1768.3	9.2	12.6	21.8	69.9	1720.1	-48.2
1987	1720.1	8.9	-8.9	0.0	68.4	1651.7	-68.4
1988	1651.7	13.9	50.7	64.6	88.6	1627.7	-24.0
1989	1627.7	19.0	88.8	107.8	85.8	1649.7	22.0
1990	1649.7	28.0	60.0	87.8	90.1	1647.4	-2.3

– not available

Source: Alberta Energy Resources Conservation Board; compiled by National Accounts and Environment Division, Statistics Canada

Table 5: Remaining Established Reserves of Marketable Natural Gas in Alberta; Data from the Canadian Petroleum Association (billions of cubic metres)

Year	Opening Stock	Gross Additions	Depletion	Closing Stock	Net Changes
1962	..	..	17.5	792.0	
1963	792.0	76.4	19.5	848.9	56.9
1964	848.9	201.2	21.9	1028.2	179.3
1965	1028.2	65.0	24.0	1069.1	41.0
1966	1069.1	80.5	25.4	1124.2	55.1
1967	1124.2	60.8	27.4	1157.6	33.4
1968	1157.6	-0.8	31.0	1125.8	-31.9
1969	1125.8	223.2	36.7	1312.3	186.5
1970	1312.3	83.2	42.9	1352.6	40.3
1971	1352.6	92.1	47.5	1397.2	44.6
1972	1397.2	24.2	52.2	1369.2	-28.0
1973	1369.2	83.1	55.5	1396.8	27.6
1974	1396.8	66.6	56.8	1406.6	9.8
1975	1406.6	100.3	58.1	1448.7	42.2
1976	1448.7	59.5	59.5	1448.8	0.1
1977	1448.8	92.1	62.7	1478.3	29.4
1978	1478.3	133.1	61.7	1549.7	71.4
1979	1549.7	162.9	66.2	1646.4	96.7
1980	1646.4	77.1	62.1	1661.4	15.0
1981	1661.4	123.6	62.0	1723.1	61.7
1982	1723.1	69.3	64.1	1728.4	5.2
1983	1728.4	77.0	60.6	1744.8	16.4
1984	1744.8	219.9	65.8	1898.8	154.0
1985	1898.8	1.1	72.8	1827.1	-71.8
1986	1827.1	-8.7	68.4	1750.0	-77.1
1987	1750.0	47.4	69.6	1727.7	-22.3
1988	1727.7	48.8	88.5	1688.0	-39.7
1989	1688.0	102.9	85.4	1705.6	17.5

... not available

Source: Canadian Petroleum Association

Table 6: Remaining Established Reserves of Natural Gas Liquids in Alberta: Ethane in Gas including Solvent Flood[1]
(millions of cubic metres, liquid)

Year	Opening Stock	Reserves Beyond Economic Reach	Production	Closing Stock
1961	-	-	-	-
1962	-	-	-	-
1963	-	-	-	-
1964	-	-	-	-
1965	-	-	-	-
1966	-	-	-	-
1967	-	-	-	-
1968	-	-	-	-
1969	-	-	-	-
1970	-	-	-	-
1971	-	-	-	-
1972	-	-	-	-
1973	-	-	0.6	274
1974	274	-	0.7	274
1975	274	-	0.5	279
1976	279	-	0.3	279
1977	279	-	0.5	276
1978[2]	276	-	1.5	286
1979[2]	286	-	3.6	291
1980[2]	291	-	4.5	295
1981	295	12.0	4.7	307
1982	307	5.5	4.2	320
1983	320	6.4	4.7	316
1984	316	11.2	5.6	320
1985	320	7.1	5.8	321
1986	321	7.4	6.1	315
1987	315	8.4	7.1	314
1988	314	9.3	7.6	321
1989	321	9.5	7.3	330

1. Established reserves include those reserves beyond economic reach
2. Non-economic reserves not identified for these years

Source: Alberta Energy Resources Conservation Board

Table 7: Remaining Established Reserves of Natural Gas Liquids in Alberta: Propane[1]
(millions of cubic metres, liquid)

Year	Opening Stock	Reserves Beyond Economic Reach	Additions	Production	Closing Stock
1961	-	0.2	3.2	-	22.5
1962	22.5	0.3	17.9	-	40.5
1963	40.5	-	0.0	-	40.2
1964	40.2	-	13.0	1.0	52.3
1965	52.3	-	5.8	1.5	56.5
1966	56.5	-	6.4	1.8	61.1
1967	61.1	-	5.5	2.0	64.6
1968	64.6	-	31.5	2.3	93.8
1969	93.8	-	20.3	2.7	111.4
1970	111.4	-	-5.2	3.2	102.9
1971	102.9	-	1.8	3.7	101.1
1972	101.1	-	4.3	4.6	100.8
1973	100.8	-	13.1	4.9	109.2
1974	109.2	-	-0.7	4.9	103.7
1975	103.7	0.0	-1.1	5.3	97.3
1976	97.3	-	12.3	5.1	104.5
1977	104.5	-	5.4	5.4	104.3
1978[2]	104.3	-	9.3	5.0	108.6
1979[2]	108.6	-	2.6	5.5	105.7
1980[2]	105.7	-	19.3	5.3	119.7
1981	119.7	2.6	8.9	5.2	123.4
1982	123.4	1.0	9.9	5.2	128.1
1983	128.1	1.2	3.8	4.7	127.2
1984	127.2	2.0	4.4	5.1	126.5
1985	126.5	0.9	4.6	5.5	125.6
1986	125.6	1.1	4.7	4.7	125.6
1987	125.6	1.7	4.8	5.0	125.4
1988	125.4	2.2	4.4	5.6	124.2
1989	124.2	1.6	11.2	6.0	129.4

1. Established reserves include those reserves beyond economic reach
2. Non-economic reserves not identified for theses years

Source: Alberta Energy Resources Conservation Board

Table 8: Remaining Established Reserves of Natural Gas Liquids in Alberta: Butane[1] (millions of cubic metres, liquid)

Year	Opening Stock	Reserves Beyond Economic Reach	Additions	Production	Closing Stock
1961	-	0.3	1.6	-	16.9
1962	16.9	0.3	8.9	-	25.7
1963	25.7	-	0.0	-	25.4
1964	25.4	-	8.9	0.8	33.5
1965	33.5	-	4.5	1.0	37.1
1966	37.1	-	4.7	1.2	40.6
1967	40.6	-	4.0	1.3	43.3
1968	43.3	-	18.4	1.5	60.2
1969	60.2	-	11.5	1.7	69.9
1970	69.9	-	-1.3	2.1	66.6
1971	66.6	-	2.1	2.4	66.3
1972	66.3	-	2.6	3.0	65.8
1973	65.8	-	6.7	3.2	69.4
1974	69.4	-	1.6	3.2	67.7
1975	67.7	0.0	-1.6	3.4	62.7
1976	62.7	-	4.7	3.4	63.9
1977	63.9	-	3.9	3.5	64.3
1978[2]	64.3	-	11.6	3.2	72.8
1979[2]	72.8	-	2.0	3.5	71.3
1980[2]	71.3	-	1.8	3.3	69.8
1981	69.8	1.2	3.7	3.1	70.4
1982	70.4	0.6	5.7	3.1	73.0
1983	73.0	0.7	1.5	3.0	71.5
1984	71.5	1.2	3.4	3.1	71.8
1985	71.8	0.5	1.7	3.1	70.4
1986	70.4	0.7	1.8	2.8	69.4
1987	69.4	0.9	6.6	3.0	73.0
1988	73.0	1.3	3.3	3.3	73.0
1989	73.0	0.9	3.3	3.2	73.1

1. Established reserves include those beyond economic reach
2. Non-economic reserves not identified for these years

Source: Alberta Energy Resources Conservation Board

Table 9: Remaining Established Reserves of Natural Gas Liquids in Alberta: Pentanes Plus[1] (millions of cubic metres)

Year	Opening Stock	Reserves Beyond Economic Reach	Additions	Production	Closing Stock
1961	-	1.5	3.7	-	69.0
1962	69.0	0.9	0.2	-	69.2
1963	69.2	0.4	8.4	-	78.2
1964	78.2	1.6	12.9	3.7	87.4
1965	87.4	1.7	28.1	8.8	106.7
1966	106.7	0.1	-4.2	4.5	98.0
1967	98.0	2.2	14.0	4.5	107.4
1968	107.4	1.4	46.3	5.2	148.5
1969	148.5	1.3	23.9	5.9	166.5
1970	166.5	2.4	21.5	6.8	181.2
1971	181.2	0.6	-15.5	7.2	158.5
1972	158.5	0.6	-1.1	9.4	148.1
1973	148.1	0.2	9.9	9.6	148.4
1974	148.4	1.4	0.7	9.2	139.9
1975	139.9	0.0	-3.8	8.6	127.5
1976	127.5	1.4	4.9	7.5	124.9
1977	124.9	1.4	7.0	7.3	124.5
1978[2]	124.5	-	4.7	6.6	122.6
1979[2]	122.6	-	8.5	6.5	124.6
1980[2]	124.6	-	-14.0	5.9	104.7
1981	104.7	5.1	28.4	5.7	127.4
1982	127.4	2.4	-2.7	5.6	119.1
1983	119.1	2.1	-0.5	5.3	113.3
1984	113.3	5.3	17.1	5.5	124.9
1985	124.9	2.1	1.0	5.8	120.1
1986	120.1	1.9	5.7	5.8	120.0
1987	120.0	2.7	15.6	6.2	129.4
1988	129.4	3.4	6.0	6.4	129.0
1989	129.0	3.1	0.9	6.4	123.5

1. Established reserves include those beyond economic reach
2. Non-economic reserves not identified in these years

Source: Alberta Energy Resources Conservation Board

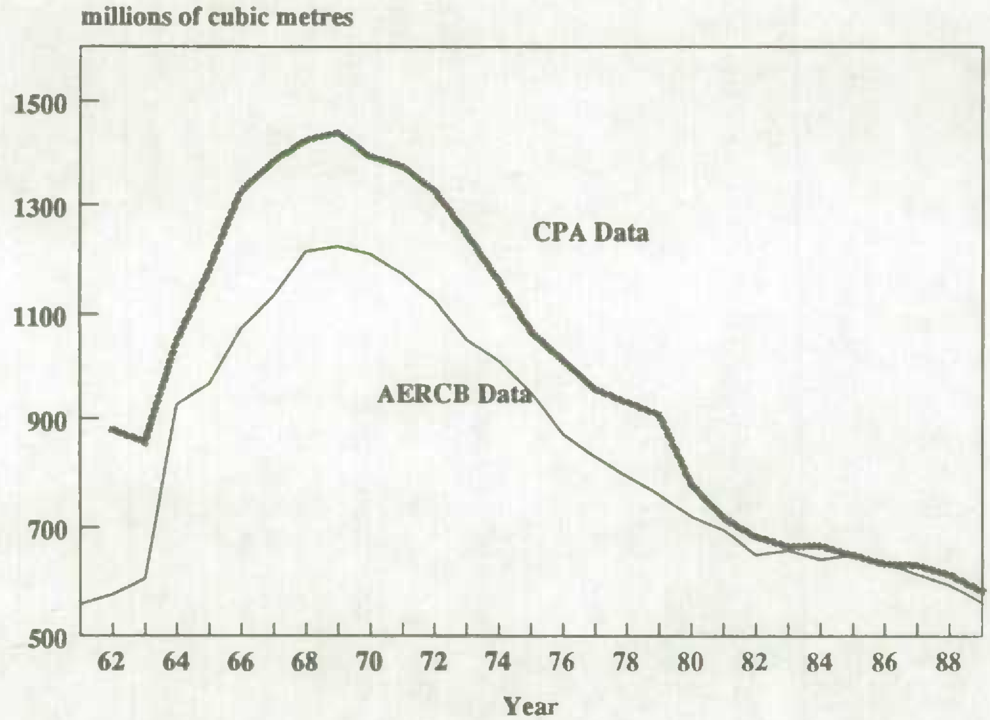
Table 10: Established Reserves of Sulphur from Natural Gas Production in Alberta (millions of tonnes)

Year	Opening Stock	Reserve Additions	Production	Production CPA[1]	Closing Stock
1961	-	-	-	0.4	-
1962	-	-	-	1.0	81.6
1963	-	-	-	1.2	71.9
1964	71.9	0.6	1.4	1.4	71.1
1965	71.1	19.2	1.5	1.6	88.8
1966	88.8	24.1	1.7	1.7	111.2
1967	111.2	8.8	2.1	2.2	117.9
1968	117.9	26.5	3.0	3.0	141.5
1969	141.5	4.4	3.8	3.7	142.1
1970	142.1	23.9	4.3	4.2	161.7
1971	161.7	-3.5	4.6	4.6	153.6
1972	153.6	-1.3	6.6	6.7	145.7
1973	145.7	6.0	7.1	7.1	144.6
1974	144.6	-0.7	6.9	6.8	137.1
1975	137.1	5.5	6.5	6.5	136.0
1976	136.0	-16.6	6.2	6.3	113.3
1977	113.3	2.0	6.5	6.4	108.8
1978	108.8	-1.5	6.3	6.3	101.0
1979	101.0	3.1	5.9	6.1	98.1
1980	98.1	-8.3	5.7	6.0	84.1
1981	84.1	1.2	5.4	5.7	79.9
1982	79.9	7.0	5.0	5.3	81.9
1983	81.9	5.3	5.1	5.5	82.1
1984	82.1	0.4	5.1	5.4	77.4
1985	77.4	0.7	5.0	-	73.1
1986	73.1	1.9	4.9	-	70.1
1987	70.1	18.1	5.0	-	83.2
1988	83.2	5.9	5.1	-	84.0
1989	84.0	7.3	4.7	-	86.6

1. From CPA Statistical Yearbook Section III, Table 11

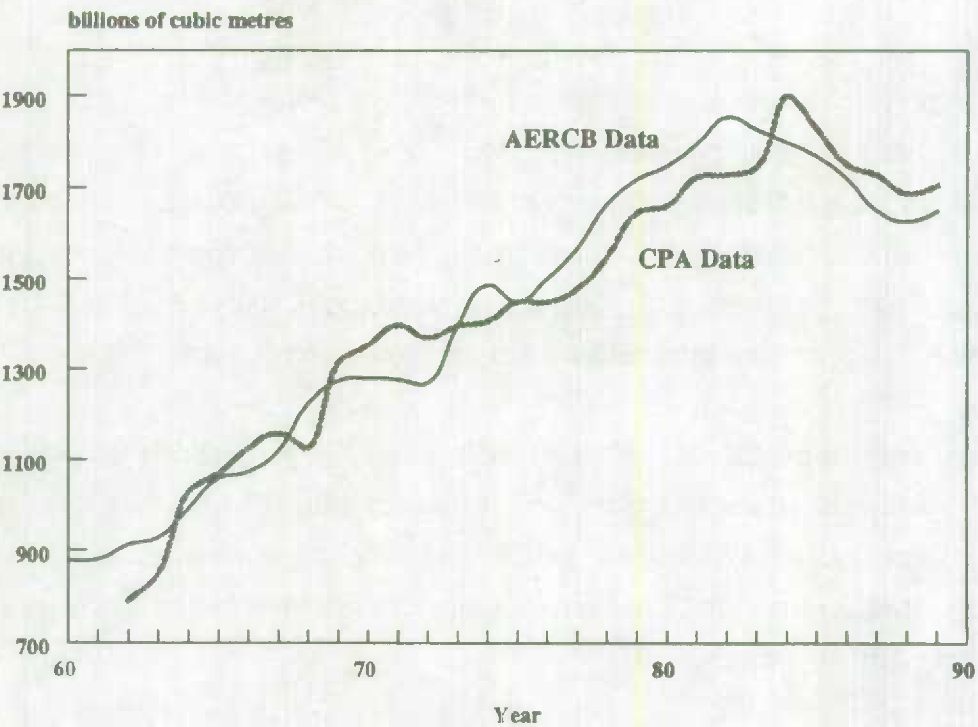
Source: Alberta Energy Resources Conservation Board

Figure 2. Remaining Established Reserves of Crude Oil in Alberta



Source: AERCB and CPA

Figure 3. Remaining Established Reserves of Natural Gas in Alberta



Source: AERCB and CPA

Large increases in the "discoveries" category as reported by the AERCB in the late 1960s and late 1970s reflect increasing oil prices which in turn resulted in increased spending in exploration.[4] Since 1980 reserve additions have increased due to increased emphasis on oil exploration (Tanner, 1986).

The AERCB provides a complete times series of reserves additions, production and remaining reserves on an **established** reserves basis from 1951. The CPA has a break in its series prior to 1962 where it was reporting these categories on a proven basis. Because of the recaps consistent time series and the fact its production data closely match the production volume reported in Statistics Canada, The Crude Petroleum and Natural Gas Industry (Catalogue 26-213), reserve data published by AERCB are used in valuing oil and gas reserves for Alberta.

It should be noted that estimates from the AERCB for oil and gas reserves are used to establish allowable production levels and export availability whereas estimates from the CPA are not subject to these "regulatory pressures". However, the CPA does not have access to all data available to the AERCB. The estimates from the CPA do provide an excellent check for the data from the AERCB and the National Energy Board (NEB).

Reserves data from the AERCB are also used in studies prepared by Eglington and Uffelmann (1983), McLachlan (1990), Pasay (1987) and Uhler and Eglington (1986).

5.0 THE CONCEPT OF ECONOMIC RENT

The concept of economic rent is central to the monetary valuation of natural resources (Repetto et al, 1989). Economic rent constitutes the difference between the international commodity price and all factor costs of extraction, including a normal return to capital but excluding taxes, royalties and other costs that are not part of the cost of physical extraction.

Economic rent from petroleum exploitation is the return accruing to investors over and above those necessary to sustain:

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4. In terms of the McKelvey Box, increased exploration efforts expanded the vertical axis of identified reserves (see Figure 1).

1. ongoing production from existing fields
2. the further development of discovered fields
3. new exploration.

These are the marginal costs necessary to replace the existing stock of the natural resource in the long-run. Measurement of these rents requires knowledge of the costs of finding, developing and operating oil and gas fields, production profiles, oil and natural gas prices and discount rates (Kemp, 1987).

In accounting for non-renewable resources in the extractive industry, it is important to determine the net value-added from the resource. The return to this factor of production is economic rent (Landefeld and Hines, 1985). It is also important to distinguish the value added from the resource from that value added associated with the physical (man-made) capital used to extract the resource. The value added from the resource is defined as the net revenue from the resource less all factor payments including a normal return to capital. That is, the value of the natural resource stock is the discounted present value of the net revenue.[5]

Economic rents from natural resources consist of Hotelling rents (scarcity or exhaustibility) and Ricardian rents (differential or varying quality) as well as locational rents (arising from transportation costs) and rents arising from unexpected price variations. While much of the literature on monetary valuation of natural resource stocks has focussed on aggregate economic rent or Hotelling rents, there is little discussion on how to treat these different rents in the context of developing natural resource accounts. In most models, it is assumed that stocks are homogeneous and that there are no differential or Ricardian rents.

Most of the literature suggests that it is the Hotelling or scarcity rent that should be used to measure depletion of the resource. Treatment of these rents in terms of monetary accounts is discussed below.

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5. The net price should be net of all costs including capital costs so that it can accurately represent the value added of the natural resource (Landefeld and Hines, 1985).

5.1 The Concept of Hotelling Rent

In 1931, Hotelling provided a theoretical model of the behaviour of markets for exhaustible resources. The Hotelling "hypothesis" states that under certainty, in the absence of extraction costs and under competitive market conditions, the price of a natural resources rises at the market rate of interest to preclude arbitrage (Sundarsen, 1984).

The ability of the theory of exhaustible resources to describe and predict actual behaviour of natural resource markets remains an area of considerable debate and with little empirical support. However, several recent studies in natural resource accounting use the Hotelling model as the method of monetary valuation ("the unit value of the total reserve is the same as the current net price") without examining the restrictive assumptions of the Hotelling model. Appendix I provides a theoretical discussion of the Hotelling hypothesis followed by a discussion of its implications in natural resource accounting.

5.2 Value of Oil and Natural Gas Reserves

The value of reserves can be calculated from current prices and costs using the Hotelling model:

$$V_t = (p_t - c_t) R_t$$

where V_t is the value of the reserve stock, R_t is the volume of reserves, and $(p_t - c_t)$ is the net price. This is the basis of the "Net Price" method discussed below.

While determining the value of the Hotelling rent in each year is important in calculating the value of the reserves, using the Hotelling model that assumes the rent increases (under the assumption of increasing commodity prices) at the rate of interest may be incorrect. Merely taking the net price in the current year and ignoring other economic and technological factors may be wholly inappropriate.

6.0 MARKET AND ACCOUNTING VALUATION OF OIL AND GAS RESERVES

The purpose of this section is to present the different market and accounting measures used to value oil and gas properties by the industry. The focus of monetary valuation of sub-soil assets proposed in the UN SNA Handbook (1990) has been on using market valuation or proxies of it. Because oil and gas properties are rarely traded separately, their market values are generally not available. However, oil and gas firms are required to disclose several accounting measures that can be used to determine the monetary value of the firm's oil and gas properties. Several authors have tried to test the consistency of market data with the implications of the theory of exhaustible resources.

6.1 Imputed Market Value

Miller and Upton (1985a, b), Magliolo (1986) and Harris and Ohlson (1987) have tried to determine the relationship between accounting valuation methods and an imputed market value of oil and gas properties. Their goal was to determine whether or not the discounted or undiscounted net present value data, net book values and direct profit measures can measure imputed market values (defined below). The imputed market value is assumed to represent the market participants' estimates of reserve values (Magliolo, 1986). Also, these authors attempt to test the Hotelling valuation model.

Miller and Upton (1985a, b), Magliolo (1986) and Harris and Ohlson (1987) used the firm's equity adjusted for non-oil and gas assets and liabilities as a proxy for the market valuation. This imputed market value of oil and gas properties is:

$$IV = \frac{\text{Value of equity and liabilities - value of non-oil/gas assets}}{\text{Units of equivalent of proved reserves}}$$

Market values were used for marketable debt and equity while book values are used for current liabilities (short-term debt) and for non-oil and gas assets. It should be noted that this market value does not depend on the book value of oil and gas properties. While this imputed market value is used to infer a value of reserves, Landefeld and Hines (1985) suggest that the imputed market value has several problems. There are difficulties in separating the value of the reserves from the value of other assets, the use of both current and historical dollars and that stock prices tend to reflect the overall investment outlook rather the actual value of the company.

In the models presented by Miller and Upton (1985a, b), Magliolo (1986) and Harris and Ohlson (1987), several independent measures are regressed against the imputed market value discussed above. These measures are the net book value, undiscounted and discounted present values and direct profit. Values for these measures can be obtained from annual and SEC 10K reports as well as from J.S. Herold's Oil Industry Comparative Appraisals. Below is a discussion of the definitions of each of these variables.

6.2 Net Book Value

Net book value comprises the cost of properties that are unamortized (i.e. exploration expenditures) and the cost of properties that are amortized less accumulated depletion, depreciation and amortization charges. Net book value of oil and gas reserves is defined as:

$$BV = \frac{\text{net book value}}{\text{units of equivalent of proved reserves}}$$

6.3 Current and Present Value

There are also three current value measures of oil and gas properties reported in company annual and SEC 10K Reports:

6. Units of equivalent of proved reserves are calculated by deflating crude oil and natural gas reserves into a single reserve volume. Crude oil and natural gas reserves are converted on an equivalent energy basis where 1 cubic metre of crude oil is approximately equal to 1000 cubic metres of natural gas. There is some debate in the literature on which conversion factor to use (e.g. price or energy equivalency), however, most studies use an energy conversion.

1. Reserves Recognition Accounting (RRA) Valuation Method (Standardized Present Value of Net Future Cash Flows):

$$PV = \frac{\text{present value of future net cash flows}}{\text{equivalent unit of proved reserves}}$$

where net cash flows are discounted at ten per cent and future net cash flows are computed using year-end prices and costs.

2. Undiscounted Net Future Cash Flows (UNR method):

$$UNR = \frac{\text{net future cash flows}}{\text{equivalent unit of proved reserves}}$$

where net cash flows are the same as in (1) but the discount rate is zero per cent.

3. Direct Profit:

$$DP = \frac{\text{direct profit margin}}{\text{equivalent unit produced in current year}}$$

where direct profit is defined as average sales price less direct lifting costs (operating costs and related overhead expenses).

Harris and Ohlson (1987) suggest that the DP measure is equal to the Hotelling rental value assuming that future profit margins increase at the risk-free rate of return. Similar to the Hotelling world, the DP method excludes development and exploration costs which are included in the RRA and UNR methods.

6.4 Reserves Recognition Accounting (RRA) Valuation

In 1979, the Securities and Exchange Commission (SEC) adopted the requirement that the RRA method be provided as part of supplemental disclosures for oil and gas producers. The RRA is based on a discounted cash flow or present value methodology which assumes the continuation of current oil and gas margins discounted at 10 per cent.[7] The SEC recognizes that the valuations of proved reserves under the RRA method are not the best estimates of the fair market value of a firm's oil and gas properties because of the SEC's restrictions on what type of reserves can be reported, on forecasts of future economic conditions and the discount rate used. However, the RRA method allows for qualitative, quantitative, geographic and temporal characteristics of oil and gas reserves (FASB, 1982).

In the RRA method, current economic conditions and a uniform discount factor are specified in order to achieve uniformity. This approach differs from discounted future net cash flows where estimates for future prices, costs and enterprise-specific discount rates are not held constant. Discounted future net cash flows are calculated by companies for internal purposes and are not publicly reported.[8]

RRA requires that the expected net cash flows from the sales of proved reserves be determined from current prices and extraction costs (including exploration and development expenditures)[9] discounted at a 10 per cent real rate. The RRA reserve value is calculated from:

$$\text{RRA value} = (p_0 - c_0) \sum_{j=1}^{T} \frac{q_j}{1.1^j}$$

where p_o is current price of oil, c_o is current cost of extraction and q_j quantity extracted in period j.[10]

7. Cash flow is the difference between gross current cash income and gross cash expenditures and present value of future development and production costs. Costs include acquisition and exploration costs.
8. One exception is Pancontinental Oil Ltd. where consolidated present value of reserves is reported using projected future commodity prices and 0, 15, 20 percent discount rates.
9. This reporting aspect needs to be clarified. According to the SEC Rules and Regulations (1979), expenses for the period should consist of all costs associated with finding and developing reserves as well as non-productive expenses. Final rules of the SEC Supplemental Disclosures specify that acquisition and development costs may be deferred but must be assessed periodically.

6.5 Hotelling Rents as a Proxy for Imputed Market Values

Several authors (Miller and Upton, 1985a, b; Magliolo, 1986; and Harris and Ohlson, 1987) attempt to determine if there is a correlation between the imputed market value and other current values discussed above. They also assume that UNR and DP measures can be used as proxies for Hotelling rent, that is $p_o - c_o$ can be used to measure IV.

Miller and Upton (1985a) and Magliolo (1986) base the reserve value on Hotelling's model:

where p_o is the wellhead price, c_o is the unit average cost of extraction and R_o is stock of reserves remaining at the end of the current period.[11]

Miller and Upton calculated an Hotelling rent from:

$$HR = \frac{p_t - c_t - c_{DT}}{(1+r)^t}$$

where c_{DT} is the unit exploration costs to arrive at a current market valuation based on RRA and J.S. Herold data discounted at 10 per cent.[12]

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10. The Hotelling Valuation Principle formula derived by Miller and Upton (1985a) is:

$$V_0 = (p_0 - c_0) \sum_{t=0}^{N} q_t = (p_0 - c_0) R_0$$

11. Under conditions of noncontinuous returns to scale and increasing extraction cost with cumulative production, the formula becomes:

$$IV = (p_0 - \bar{c}_0) + K_1 + K_2$$

where c_o is the average cost of extraction, K_1 and K_2 are constants relating to differences between marginal and averages costs and increasing extraction costs.

The Hotelling model assumes constant returns to scale (CRS) where the unit net price of the resource should increase through time at the rate of interest. Under these assumptions, then the marginal cost is the same as the average cost (Miller and Upton, 1985a). The value of the total reserves in any mineral property depends on current price per unit of the mineral net of current extraction costs.

Under the assumptions of constant unit prices and costs, the undiscounted net revenues (UNR) which are disclosed in SEC 10K reports should equal the value of the firm's reserves as in:

$$UNR = \sum_{j=1}^{T} (p_0 q_j - c_0 (q_j))$$

where p_{oj} is total revenue and $c_o(q_j)$ is the total cost to produce q_j and UNR measures the expected gross margin, undiscounted over the life of the reserves. If the unit price or extraction cost varies with the quantity produced, then unless the average price and extraction cost rise at the rate of interest (assuming that the Hotelling rule is valid), the UNR will not generally value the firm's reserves correctly (Magliolo, 1986). If unit extraction cost is constant, the value of the reserves must be as predicted in the Reserve Value or an arbitrage opportunity would exist. However, the reserve value defined by Hotelling is not robust with respect to the introduction of uncertainty where expectations about future prices are not necessarily linked to current prices (Magliolo, 1986).

12. Hartwick (1989) suggests that Miller and Upton's approach is incorrect and the value of the Hotelling rent in period t should be:

$$HR = (p_t - C_{q(t)}) q_t - C_{D(t)} D_t$$

that is the Hotelling rent net of exploration costs where q_t is the quantity of reserves extracted and D_t is the quantity of reserves discovered. It should be noted the Miller and Upton's "HOTEL" variable (which is what Miller and Upton equate to their "Hotelling Valuation Principle") is based on direct profit measures derived from J.S. Herold. DP represent current price net of extraction (operating) costs and does include exploration costs. In their other model, they also use discounted RRA (where exploration and development costs are netted out) and J.S. Herold values to explain IV. It is Hartwick (1989) that has derived the above equation on the assumption that the discounted RRA and J.S. Herold values are equivalent to Hotelling rents.

The RRA value defined above will be less than the Reserve Value because prices and costs are intertemporal constants in the RRA valuation. If the Reserve Value expression is true, the net price (p_o - c_o) increases through time so as to offset exactly the discounting. The RRA value does not allow for the increase in price and thus undervalues the reserves.

While these market valuations are used to measure the firm's value of oil and gas reserves, there is concern that both the left hand side and right hand side variables in the regression equation are measured with error. For example, the imputed value (IV) uses both market and historical values (Lys, 1987). Also there is the implicit assumption that J.S. Herold, DP and UNR measure of net price or economic rent behave in a Hotelling-like manner if they correlate to the imputed market value of the firm's oil and gas reserves.

Miller and Upton (1985a, b) compare the imputed market value to the net price derived from the Hotelling model where the net price data are obtained from J.S. Herold reserve valuation, DP and discounted RRA data. Miller and Upton test the following regressions in order to explain IV:

$$IV = \alpha + \beta (p_i - c_i)$$

$$IV = \alpha + \beta \frac{PV}{S_i}$$

where S_i is the total stock of proven reserves, and

$$IV = \alpha + \beta (p_0 - c_0)$$

In the last equation, $(p_o - c_o)$ represents average net current price derived from *DP* values (average sales price less direct lifting costs) (Harris and Ohlson, 1987). Their results from regressing imputed market values per unit of reserves for oil and gas properties on current wellhead prices net of marginal extraction costs (*DP*) support HVP for the years 1979 to 1981 but fail after 1981.[13]

13. It is not clear whether Miller and Upton extracted the DP directly from 10K Reports or used DP values from Herold reports. It should be noted that exploration and development costs are not included in the DP measure.

Results from another test by Miller and Upton (1985a, b) show that data from J.S. Herold[14] explained better the imputed market value of reserves than the discounted RRA value, PV. But this superiority did not continue from 1981 to 1983 where oil prices were stable compared to the 1979 to 1981 period (Miller and Upton, 1985b and Magliolo, 1987).

Magliolo (1986) constructs a model that links the undiscounted RRA data to the imputed market value of the firm. Magliolo assumes that unit prices and costs do not vary with the quantity extracted. He assumes that $(p_o - c_o)S_o$, a Hotelling value for the reserves, is the same as the undiscounted net revenues (i.e. UNR described above).

Magliolo tests the following regressions under the assumptions of CRS (on an after-tax basis):

$$IV = \alpha + \beta \frac{UNR}{S_i}$$

and

$$IV = \alpha + \beta (p_i - c_i)$$

where S_i is the units of equivalent proven reserves and $(p_i - c_i)$ data are obtained from J.S. Herold.[15] Results from using UNR and values from J.S. Herold as the predicted values of reserves indicate the coefficient values do not behave as predicted and the correlation between IV and UNR on an after-tax basis is poor for the years 1979 to 1983.[16] However, Magliolo obtains similar β coefficients to Miller and Upton (1985a, b) when he restricts the tax coefficients to zero for the regression firm values on oil and gas values based on J.S. Herold data.[17]

14. Herold calculations represent a "discounted cash flow" measure: discounted at 10 percent with estimates of future prices and costs. Unit operating costs reflect the reserve life of each firm (Miller and Upton, 1985a).

15. It is not clear whether or not the data from J.S. Herold is direct profit or discounted cash flow. I assume that it is the former because Magliolo tries to compare his results with Miller and Upton's "HOTEL" variable.

16. Magliolo does not test HVP explicitly (where $(p_i - c_i)$ "evolves" through time at the rate of interest) because it would require a time-series which not possible since RRA data are available from 1979 only. What is important to our project is whether or not UNR or PV are valid measures of the market value of the reserves. Of course, there is the problem of whether or not IV represents the imputed market value of reserves.

17. Magliolo does not conduct a similar regression using IV on UNR values.

Harris and Ohlson (1987) test the relation between IV (dependent variable) and BV, PV, UNR and DP (independent variables) for oil and gas properties in the United States during the years 1979-1983. Their results indicate that BV and to a lesser extent PV values were significant in explaining the imputed market value, IV. The DP and UNR values were not significant. Harris and Ohlson assume that the DP measure represents a Hotelling value for the oil and gas reserves. Their results implicitly suggest that a Hotelling value does not measure the imputed market value of reserves.

While these market valuations are used to measure the firm's value of oil and gas reserves, there is concern that both the left hand and right hand side variables in the regression equations are measured with error. For example, the imputed value (IV) uses both market and historical values (Lys, 1986). Also there is the implicit assumption that J.S. Herold, DP and UNR measure of net price or economic rent behave in a Hotelling-like manner if they correlate to the imputed market value of the firm's oil and gas reserves.

For our purposes, data obtained from company Annual and 10K Reports provide a benchmark from which we can evaluate our results using present value and net price methods to value Canada's oil and gas reserves. It is important to realize we are relying on data from companies reporting to Statistics Canada and the Canadian Petroleum Association. We also use a less conservative definition of reserves than is reported in the standardized discounted net cash flow measure. When companies prepare their RRA valuations, the SEC requires that the level of aggregation used be based on oil and gas fields or other appropriate groupings where it can be reasonably expected to result in comparable price and cost data at a more detailed level (SEC, 1979, p. 57033). Data from RRA valuations should provide a weighted average discounted and undiscounted "net price" for each firm. Calculations from this study provide an average net price for each province at the industry level.

Table 11 compares reserve values derived from the "standardized measure of discounted future net cash flows" and direct profit margins (obtained from company Annual and 10K Reports) with results from the present study.[18] Also, where possible the value of purchased and sold reserves were calculated from company reports. Preliminary results for the period 1983 to 1989 indicate that "standardized" present values and purchase value of reserve per cubic metre determined from

18. The results presented in this table represent, as closely as possible, the accounting methodology used in the RRA value. However, we use actual and moving averages to calculate future income streams for the life of the reserves. These values do not necessarily conform the treatment of expenditures in the CSNA and the monetary accounts that are presented in Section VII.

Table 11: Accounting Disclosures and Market Valuation of Oil and Gas Properties in Canada (current dollars per cubic metre of proven reserves based on oil energy equivalent)[2,3]

	1983	1984	1985	1986	1987	1988	1989
1. Future Net Cash Flow (0% discount rate)							
Dome Petroleum Limited	69.69	67.56	76.23	39.23	35.97	..	..
Tuxedo Canada Inc.	110.35	137.05	147.47	85.48	65.12	56.45	..
Gulf Canada Corporation	62.04	69.91	66.18	31.87	44.03	34.35	44.30
Imperial Oil Limited	117.92	147.32	169.00	63.43	62.31	39.95	72.90
Shell Canada Limited		101.90	116.30	72.13	68.37	58.43	59.15
Amoco Canada Petroleum Company Limited		99.35	120.03	65.11	58.66	41.13	48.58
Canadian Occidental Petroleum Ltd.		73.30	90.55	61.33			
Ranger Oil Limited				66.48	53.07	46.42	
Results from present study (crude oil, Alberta)	88.43	83.31	69.94	63.01	64.99	64.33	70.59
2. Discounted Net Cash Flow (10% discount rate)							
Dome Petroleum Limited	35.49	34.26	34.40	22.63	21.76	..	..
Texaco Canada Inc.	56.88	66.13	68.63	35.75	26.96	25.11	..
Gulf Canada Corporation	38.87	37.46	41.29	22.26	24.81	20.70	26.74
Imperial Oil Limited	44.12	63.52	78.35	32.47	27.74	16.73	33.80
Shell Canada Limited		47.46	56.40	34.20	32.96	28.06	25.21
Amoco Canada Petroleum Company Limited		46.55	57.25	32.35	28.59	22.24	25.63
Canadian Occidental Petroleum Ltd.		39.69	47.17	31.54			
Ranger Oil Limited				32.91	28.85	24.24	
Results from present study (crude oil, Alberta)	52.99	47.61	36.59	28.38	28.95	27.50	31.72
3. Sale of Reserves in Place							
Dome Petroleum Limited	30.51			14.70-21.96[1]			
Gulf Canada Corporation			39.19				29.10
4. Purchase of Reserves in Place							
Dome Petroleum Limited	30.53	32.86					
Texaco Canada Inc.						21.55	
Imperial Oil Limited							28.76
Shell Canada Limited							30.00
5. Net Price - Crude oil [4]							
Dome Petroleum Limited	170.83	181.34	191.34	85.63	113.32		
Texaco Canada Inc.	161.84	165.85	174.39	97.61	120.74	86.07	
Shell Canada Limited	147.17	150.51	159.81	76.94			
Ranger Oil				76.23	104.79	67.37	
Results from present study	138.91	183.79	183.02	86.21	107.87	70.10	89.78
6. Net Price - Natural gas ($/000 cu m) [4]							
Dome Petroleum Limited	93.90	98.49	91.78	76.60	58.60		
Texaco Canada Inc.	56.28	57.69	38.86	45.02	31.31	29.63	
Shell Canada Limited	78.06	78.27	68.90	51.07			
Ranger Oil				56.89	41.19	38.67	
Results from present study							
7. Average extraction costs							
Dome Petroleum Limited	21.52	21.83	24.98	25.11	22.97		
Texaco Canada Inc.	43.72	48.91	59.63	35.46	27.99	27.56	
Shell Canada Limited	25.65	26.93	28.72	31.52			
Amoco Canada	33.98	31.77	34.92	39.01	21.53	30.58	33.84
Ranger Oil Limited - Crude Oil				41.23	29.02	29.89	
- Natural Gas ($/000 cu m)				11.28	11.23	11.50	
Results from present study - Alberta crude oil	15.26	17.40	21.43	22.62	24.56	25.31	31.88
- Canada crude oil and natural gas	22.80	24.06	26.83	27.83	25.22	22.59	25.30

[1] Results from independent market valuations

[2] Based on developed and undeveloped reserves

[3] Based on cashflows before income tax and royalties

[4] average sales price less lifting (operating) costs

Source: Annual Reports and 10 K Reports from selected companies; National accounts and Environment Division Statistics Canada company data are similar to those present values (discounted at 10 per cent) calculated from statistical data reported to Statistics Canada and the Canadian Petroleum Association. Future values (discounted at 0 per cent) and direct profit margins calculated from company data compare closely with net price values determined in this study.

While we have not calculated an imputed market value for reserves (as defined above), these results indicate that our calculations using present value and net price measures are similar to those reported by the petroleum industry in Canada for public disclosure. Models developed by Miller and Upton (1985a, b), Magliolo (1986) and Harris and Ohlson (1987) show conflicting results for explaining the imputed market value of oil and gas reserves. It is concluded that a present value approach allowing for changes in prices and total extraction costs (including exploration and development expenditures) may be the best method of valuing reserves.

7.0 ECONOMIC DEPRECIATION (DEPLETION) OF NATURAL RESOURCES

Literature on natural resource accounting has focussed mainly on the issue of economic depreciation or depletion of the natural resource and its monetary valuation. The main debate is how to treat natural resource depletion in terms of the national accounts. While the depreciation of man-made capital may be deducted from GDP to arrive at an NDP, depletion of our natural resources is not included in the production accounts. Several methods of valuing annual reserve depletion have been proposed in the literature and are discussed here.

Hartwick and Lends (1989) propose that in a competitive economy with homogeneous stocks of a natural resource, Hotelling rents equal the value of economic depreciation or resource depletion. This concept of resource depletion is equivalent to the capital consumption of reproducible or man-made capital. Current Hotelling rents can serve as a measure of economic depreciation of natural resources. They define Hotelling rents as output price minus extraction and discovery costs on the marginal unit times the quantity extracted in period t. These rents comprise income to stock owners in the calculation of national income (GDP) and several authors have suggested that these rents should be netted out of national income to account for economic depreciation of natural resource stocks.

In the case of a homogeneous stock and perfect competition in the economy, the economic depreciation of the stock in period t is that total Hotelling rent on the quantity extracted. With exploration or finding costs the Hotelling rent becomes:

$$HR = (P_t - MC_{qt} - MC^f_{qt})\, q_t$$

where MC^f is the marginal finding cost per unit.

In the case of heterogeneous stocks where costs are increasing with lower qualities of stock then the current rent overstates the current economic depreciation according to Hartwick and Lindsey (1989). The rent on the marginal ton rises at a rate less than the rate of interest r. Therefore, with declining quality of deposits as extraction continues (i.e. increasing extraction costs) the Hotelling rent becomes the upper limit on economic depreciation because the quantity extracted is worth more on average than subsequent quantities removed (Hartwick and Lindsey, 1989).

Assuming a competitive world market, it is the marginal unit extracted for the period which determines the dynamic rent (Hotelling rent less finding costs). The residual rent is the Ricardian rent due to higher quality (with lower extraction and finding costs) of intramarginal tons. In a case involving exhaustion of the stock and the extraction of successively poorer qualities of deposits, the current resource rent is the sum of the Hotelling rent and the Ricardian rent (Hartwick, 1982):

$$p_t - C_t = \left(\frac{1}{1+r}\right)^{n-t} (p_n - C_n) + \sum_{j=t+1}^{n} \left(\frac{1}{(1+r)}\right)^{j-t} C_{sj}$$

where C_t is the marginal cost of extraction related to Q extracted in period t and C_{Sj} is the cost of extraction related to Q extracted from deposit j (Hartwick, 1982, p. 282-285). This suggests that we are measuring the sum of Hotelling and Ricardian rents. Then the problem becomes how do we treat these two different rents in the National Accounts: as part of the value of the natural resource or as part of income.

It appears that the only literature on how natural resource rent should be treated in the National Accounts, that is as income, depreciation (capital consumption) or as wealth is by Hartwick (1982, 1991) and Hamilton (1991).

According to Hartwick, differential rent or Ricardian rent should be treated as income (similarly to land rent) and rent due to exhaustibility should be considered as economic depreciation. It is the economic depreciation that should netted out of consumption and fixed capital formation (see below). Hamilton (1991) states that it is the sum of Hotelling and Ricardian rents that is the correct measure of depletion. There are conceptual difficulties in separating these rents. But in a world where Canada's oil producers are price takers and where operating and finding costs are high (relative to Saudi Arabia), there is little Ricardian rent but rather locational rent (i.e. differential transportation costs). In this study, these locational rents have been deducted by using wellhead or fieldgate prices which are the prices of crude oil or natural gas before transmission charges.

Another proxy for resource quality (e.g. differences in unit costs or Ricardian rent) is well productivity (Watkins and Scarfe, 1985). For example, the Alberta oil royalty formula has a production-sensitive element and price-sensitive element. Thus Ricardian rents will be captured by the provinces through royalty rates that account for differential well productivities. Again, it would be difficult to identify this rent.

Another issue is that some resource costs cannot be directly attributed to individual deposits (e.g. exploration expenditures). What appears to be (Ricardian) rent in the short run may disappear after allowance for exploration cost over the long run.

The separation of the value of Ricardian and Hotelling rents is problematic. While the issue of Ricardian rents has been identified by Hamilton (1991), Gervais (1990), Hartwick (1989) and Bradley (1985), it has been largely ignored for national account purposes because it requires detailed cost data at the oil or gas field or formation level.[19]

With a declining quality of ore as extraction occurs, the current rent becomes the upper bound on economic depreciation as explained above. Hartwick and Lindsey (1989) estimate the upper bound on economic depreciation of oil stock for the United States in 1978. They calculate a Hotelling rent of $US2.96 per barrel which was 16.6 per cent of the price. This yields an economic depreciation of $4.7 billion in 1978. However, Hartwick and Hageman (1991) recalculate the economic depreciation to include reserve additions and revise the value to $20.8 billion.[20]

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19. The issue of Ricardian and Hotelling rents becomes important in a Hotelling model. The model assumes that it is the Hotelling rent that rises at the rate of interest and it is incorrect to assume that Ricardian would behave in the same manner.

Usher (1981) provides an estimate of economic depreciation of oil stocks in Canada for 1973 (Table 12). However, Usher's calculations of Hotelling rents do not include finding costs. Usher suggests that the quantity extracted should be valued at the shadow price of the ore in the ground which is the difference between the world price of the ore and the cost of extraction. The cost of extraction should be net of tax and royalties but inclusive of ongoing public expenditures of assistance to the mineral extracting industry.

El Serafy (1989) presents a method to estimate the "true" income from the proceeds from mineral sales by splitting total receipts into income and capital components. The price of a non-renewable resource, like petroleum should contain a user cost (or capital element) which represents the depletion of the resource. If the marginal cost of extraction was the only cost, then any surplus accruing to the sellers is pure rent and represents the value added that is included in the GDP. El Serafy discards the "depreciation" approach (as used by Hartwick and Lindsey (1989), Hamilton (1989), Repetto et al (1989), Usher (1981), etc.) and develops the "user cost" approach.

Net receipts are divided into a user cost or capital component and value added or true income component:

$$X = R - \frac{R}{(1+r)^{n+1}}$$

where R is total receipts (less extraction costs), X is true income and n the reserve life in years. R - X is the user cost. The discount rate r, reflects the rate of return that could be obtained from investing net receipts from the resource elsewhere. Thus the user cost is the present value of the net receipts from the resource calculated over the expected lifetime of the reserves. Only the user cost portion of the rent should be subtracted from GDP, according to El Serafy. That portion is equal to the part of the resource income which if reinvested would produce a constant perpetual income stream and represents the present value of revenues from resource depletion (Devarajan and Weiner, 1990). The focus of this approach is on the volume of extraction in the accounting period to the total volume of the remaining reserves. While El Serafy suggests that the user cost

20. Economic depreciation is recalculated net of operating and development to $9.74 per barrel ($61.28 per cu m) and the value of reserve additions is the finding (exploration cost) of the reserves.

Table 12: Estimate for Depletion of Crude Oil Reserves in Canada (1973)

	\$ per barrel	\$ per cubic metre
Wellhead Price	11.70	73.62
Cost of extraction	2.00	12.58
Shadow price of oil in the ground	9.70	61.04
Export tax	5.20	32.72
Royalties, income tax and profits	4.50	28.31
Volume of total Canadian oil production	716.5 10^6 bbl	113.9 10^6 cu m
Value of depreciation of oil stock	\$ 6.95 billion	

Source: Usher (1981)

approach is an appropriate measure for accounting for natural resource depletion in the GDP, he offers no method for determining the value of the total remaining reserves and its annual changes in SNA balance sheets or satellite accounts.

Calculations for natural resource depletion by Victor (1990) and El Serafy (1989) do not address that portion of economic depreciation attributable to man-made (reproducible) capital used in the petroleum industry. Depreciation of both man-made and natural resource capital is assumed to be what El Serafy calls a "user cost". El Serafy suggests that it is this capital element that should be set aside (i.e. deducted from GDP) and invested to create a perpetual stream of income. It should be noted in our valuation methods, the net man-made capital stock employed by the petroleum industry is subtracted from gross (and net) operating surplus (i.e. income streams). Thus the distinction between man-made and natural resource capital and depreciation is made in our analysis and conforms to values of fixed capital stock reported in the CNBSA.

Peskin (1989) proposes yet another approach to natural resource depletion and defines physical depreciation terms of value depreciation:

$$V_1 - V_0 = D_p + G$$

or

Value depreciation = physical depreciation minus capital gain or plus capital loss.

where V_o and V_1 are the value of the stock at the beginning and end of the period as determined by the present value of estimated cash flows to be generated over the life of the reserves. In this case the value of physical depreciation of the reserve stock is calculated by the "net price" (unit revenues less unit costs) multiplied by the units extracted in the year. Capital gains or losses are determined by the difference between (V_1 - V_o) and physical depreciation. Peskin (1989) does not explicitly discuss how value depreciation should be incorporated in national accounts or the GDP. In his presentation of the Tanzanian accounts, physical depreciation is equated with value depreciation which assumes that capital gains/losses are zero.

Several methods of monetary valuation of natural resource depreciation have been presented above. The methods employed by Hartwick, Hartwick and Lindsey and Repetto et al are used in this project with some modifications. The "depreciation" approach can be easily linked to the physical accounts of reserves and identifies changes to the value of reserves due to price changes and reserve appreciation.

Table 13 presents preliminary calculations of the physical and monetary accounts for conventional oil reserves in Alberta. The framework of the table is modelled after Repetto et al (1989).[21] The purpose of the table is to illustrate the impact of price changes, revisions to reserve quantities and economic depreciation on the opening and closing stocks. The values show that there were significant capital gains and losses caused by large price changes from 1980 to 1989. Peskin (1989) suggests that with the Repetto presentation, depreciation should be the sum of physical depreciation and capital gains and losses.

8.0 RESOURCE RENTS: RENTAL VALUE OF THE RESOURCE IN THE GROUND OR A MEASURE OF RESOURCE SCARCITY

Conceptually, resource rent is the most appropriate measure of resource scarcity. Resource rents incorporate the effects of technological change and substitution possibilities (Hartwick and Olewiler 1986). However, there are some problems involved when resource rents are used as a measure of scarcity. Rents are affected by government policies as well as market imperfections. For example, large increases in rents earned by oil producers in the 1970s cannot be attributed only to growing scarcity in the ground but rather to the restriction of supply which led to changes in prices. The non-competitive behaviour of OPEC strongly affects resource rent.

Several authors have used the cost of discovering new deposits as a proxy for resource rent. The argument is that exploration dollars will be spent (on the margin) as long as the expected gain from finding the resource equals the marginal cost of exploration (Hartwick and Olewiler, 1986). The expected discovery value of the resource stock is the present value of its expected rents. The advantage of using exploration costs is that they are available. The disadvantage is that most

21. The "net price" calculated in this table, while including all exploration, development and operating costs, does not follow the treatment of these costs used by the CSNA. In the table all costs are expensed in the year incurred.

Table 13 : Summary of Established Remaining Reserve Stock of Crude Oil in Alberta

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
PHYSICAL ACCOUNTS (millions of cu metres)										
Opening Stocks	760.2	719.9	696.0	649.4	657.8	640.7	648.5	634.7	613.8	592.9
Additions										
Discoveries	9.0	15.0	16.8	21.4	29.1	32.7	28.7	20.9	17.7	17.0
Development and Re-evaluation	5.1	7.2	-16.5	24.8	-12.0	9.7	-14.1	1.6	2.5	-3.5
Enhanced Recovery	8.6	10.4	6.6	17.9	24.1	21.6	24.6	10.5	16.5	7.8
Depletion	63.2	56.5	53.6	55.0	59.2	56.2	53.2	53.9	57.2	53.8
Net Change	-40.3	-23.9	-46.6	8.4	-17.1	7.8	-13.8	-20.9	-20.9	-32.4
Closing Stock	719.9	696.0	649.4	657.8	640.7	648.5	634.7	613.8	592.9	560.5
UNIT VALUES (Cdn$/cubic metre)										
Average Wellhead Price [1]	97.7	118.2	161.51	200.12	209.96	214.33	117.86	142.03	105.38	n.a.
Average Wellhead Price [2]	97.9	119.4	164.19	201.63	212.87	229.49	117.82	145.58	106.43	127.74
Production Costs	38.5	41.4	46.29	52.54	58.93	73.73	66.58	65.07		
67.25	62.30									
Rent (Net Price)	59.4	78.0	117.90	149.09	153.94	155.76	51.25	80.51	39.18	65.44
MONETARY ACCOUNTS (million $)										
Opening Stock	42989	42766	54276	76564	98072	98629	101010	32526	49419	23232
Additions										
Discoveries	535	1170	1981	3191	4480	5093	1471	1683	694	1113
Development and Re-evaluation	303	561	-1945	3697	-1847	1511	-723	129	98	-229
Enhanced Recovery	511	811	778	2669	3710	3364	1261	845	647	510
Depletion	3754	4406	6319	8200	9113	8754	2726	4340	2241	3521
Net Change	-2394	-1864	-5494	1252	-2632	1215	-707	-1683	-819	-2120
Revaluation	2170	13374	27782	20256	3189	1166	-67777	18576	-25369	15569
Closing Stock	42766	54276	76564	98072	98629	101010	32526	49419	23232	

[1] Actual average wellhead prices reported in CPA Statistical Yearbook

[2] Average wellhead price determined by total value of crude oil production divided by quantity of annual production

Source: National Accounts and Environment Division, Statistics Canada

estimates are average not marginal costs and will incorporate distortions that exist in the exploration process. For example, in Canada exploration for oil and gas is influenced by tax policies/incentives.

Results of average real exploration costs for oil and gas in the United States from 1947 to 1971 show an upward trend (Hartwick and Olewiler, 1986). Finding costs for oil and gas reserves in Alberta for the period 1947 to 1975 indicate that they rose also (Uhler, 1979). Discovery costs calculated over the period 1961 to 1989 in this study indicate that they have declined for crude oil and natural gas since 1982, although costs for natural gas discoveries have increased since 1985.

8.1 Replacement Cost Approach

Consumption of a unit of a resource today will have a **direct** cost (labour and capital inputs) and an **indirect** cost (the value of future consumption foregone). According to Fisher (1979), the net price of extractive output does not capture the indirect component. He defines the resource price as the sum of the marginal cost of current extraction plus the marginal user cost (e.g. Hotelling rent). However, rent has the property of decreasing as the resource stock decreases where marginal costs increase at a greater rate than resource prices. While Fisher deems this decrease in rent an inappropriate measure of resource scarcity, it may represent an appropriate measure of a nation's decreasing natural wealth. This raises the question of whether petroleum resources are becoming scarcer as more reserves are being discovered.[22]

The optimal depletion of a resource stock also involves the allocation of effort to find new sources. Fisher extrapolates that the rent of a unit extracted today will not reflect the loss in future income from that unit but rather the cost today of finding another unit to replace it. As a result of exploration and the addition of reserves, an exhaustible resource behaves like a renewable resource. The measure of scarcity becomes a measure of the effort made to obtain the resource. The stock can be increased by exploration and decreased by extraction as follows:

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22. Halvorsen and Smith (1984) show that resource scarcity as measured by the shadow price of unextracted ore for the Canadian metal mining industry has decreased from 1956 to 1974. The shadow price is obtained from estimating a "reproducible" (or replacement?) cost function.

$$\frac{dX}{dt} = f^d(E^d, t) - f^e(E^e, X, t)$$

where X is the value of the stock, f^d represents discoveries measured in physical units of the resource, E^d is the exploratory effort and $f^e(E^e, X, t.)$ is the extraction production function where f^e is the quantity extracted. The firm maximizes the discounted present value of profits which includes the marginal cost of exploration and the marginal cost of extraction. Fisher substitutes the marginal cost of exploration for the value of the Hotelling rent or marginal user cost discussed above. Thus exploration costs represent an approximation for the marginal user cost or rent.

The behaviour of rent when the resource stock can be indefinitely renewed by exploration makes the relationship between rent and depletion no longer important. Rent on a mineral resource can be estimated by the marginal replacement cost (the cost of discovering new deposits). Fisher proposes that this measure of scarcity of the resource reflects the sacrifices to obtain the resource.

Lasserre (1985) shows that it is the sum of marginal cost of discovery and the rent received on exploration prospects (not discovery costs alone) that represents an approximation for resource rent. His "full marginal discovery cost" (FMDC) equals the present value of exploration and development expenditures and land bonus payments which are interpreted as rent on exploration prospects. Lasserre (1985) uses the empirical data from the Eglington and Uffelmann (1983) study for oil and gas reserves in Alberta to derive values for the FMDC.[23] These approaches are similar to the "Replacement Value Approach" (as suggested by Gervais (1990)) discussed in Section 7.3.

But as Soloday (1980) states, costs of acquisition (exploration and development costs) are not an appropriate measure of the value of reserve additions to wealth because acquisition capital gains (i.e. the difference between the value and acquisition cost) may be considerable and should be included in a measure of the petroleum industry's income and product. It is the present value of additional reserves that should be considered investment. That is, the replacement cost approach does not incorporate unrealized capital gains or losses due to price changes.[24]

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23. We modify the Eglington and Uffelmann model to derive estimates for the replacement cost of the reserves.

24. The United Nations has suggested that changes in the value of natural resource stocks from additions, price changes and depletion should be excluded from the income accounts (Repetto et al, 1989).

9.0 NORMAL RETURN TO MAN-MADE CAPITAL AND ECONOMIC RENT

As previously stated, economic rent is defined as the international commodity price less all factor costs incurred in extraction (exploration, development, operating and transportation costs), including a normal return to capital but excluding taxes, duties and royalties (Repetto et al, 1989). Landefeld and Hines (1985) also suggest that the "net price" should be net of all capital costs. The UN *Statistical Handbook on Integrated Environmental and Economic Accounting* (p. 144, 1990) states that the discounted value of future net returns should be future market price minus all exploitation cost including a normal rent of capital.[25] But these authors do not make these terms operational.

Gervais (1990) suggests that net price should exclude return on capital when determining a "Hotelling" value for the natural resource. Also the treatment of the return on capital is a key issue for present value calculations (Gervais, 1990). As suggested by Landefeld and Hines (1985) and Gervais (1990), the value of man-made capital assets should be deducted from estimates of the total natural resource value in order to avoid double counting of man-made capital assets in the wealth accounts.

In present value calculations by Landefeld and Hines (1985), they define the average "net price" per unit of resource as the total price per unit less unit costs of extraction, development and exploration (p.9), even though the suggest that "in theory the net price should be net of all costs including capital costs".[26] Landefeld and Hines (1985) do not define or subtract any rent to physical capital. In their "net price" approach, they define net price as above, however apply a different definition in the actual net price procedure where operating costs a re subtracted from total revenue and the value of the natural component is determined by subtracting the current replacement value of the net physical capital stock from the total value of reserves (p. 15).

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25. The normal rent of capital refers to the produced assets which have been used for the exploitation of the natural resource (e.g. drilling equipment).

26. Capital cost are interpreted to represent the cost of capital since the value added from a gas well includes a return to the gas field as well as a return to the associated physical capital (p. 4, Landefeld and Hines, 1985). In accounting for non-renewable resources in mining industries, it is important to identify the net value added from the resource itself (that is economic rent). This rental value is equal to the total revenue from the resource less all factor payments including a normal return to physical capital.

Smith (1991) defines economic rent for crude oil and natural gas reserves in Alberta as the average wellhead price less exploration, development and operating cost (but not including royalties and land costs) as well as a normal return to the required physical and financial capital. This return to capital is defined as the cost of equity - 7 per cent plus the inflation rate in each year with the equity investment in oil and gas wells.

Bowers and Kutney (1990) state that the costs of capital employed are included in their estimation of marginal supply costs through the use of discounting. They suggest a real rate of 15 per cent for all capital employed (before taxes, royalties and land costs) approximates the hurdle rate used by investors.

As Ward (1982) suggests, a normal charge on the actual physical capital employed, reflecting the current average return on productive capital is the going rate of interest on long-term loans (Paragraph 79). "Normal" capital return on new investment in resource exploitation should comprise the following elements to ensure that the economic activity is maintained: reward to cover the cost of riskless capital, premium to cover risk and uncertainty in exploration and development, overall long-term risk premium to cover price volatility and inflation. Economic rent is the income over and above these normal investment returns and represents the available producers surplus that can be taxed without discouraging future investment. If it can be shown that the annual internal rate of return in mining is higher than the going or expected market return then it will be employed in that activity. A firm will normally produce if the internal rate of return exceeds the current rate of interest on existing riskless capital. The gross operating surplus is the normal return to capital and land plus the extra return for special risk and includes the value of the natural commodity. However, there is a fundamental problem of separating revenue between that part of the income flow with is attributable to the physical capital employed and that element of the income which should be discounted and allocated to the value of the resource (Ward, 1982).

Copithorne (1979), in his calculation of natural resource rents defines the opportunity cost of capital (i.e. normal rate of return on man-made capital) as:

$$\text{opportunity cost of capital} = r_t\,(K_t) + D_t$$

where r_t is the average yield on industrial bonds which represents the normal return to capital, K_t is net capital stock and D_t is depreciation of the capital stock. In theory, the net price should be net of all costs including capital costs so that it can accurately represent the value added associated with the natural resource. The real user cost of capital or implicit rental value for the use of capital or implicit rental value of the use of capital equipment includes both depreciation charge and interest cost (Branson, 1972).[27]

For the monetary valuation of oil and natural gas reserves presented below, we have calculated a return to man-made capital based on the methodology outlined by Branson (1972) and Copithorne (1979) using the replacement cost value of the net capital stock in structures, machinery and equipment, depreciation on that capital stock and the average yield on long-term corporate bonds reported in the *Bank of Canada Review*.

10. DISCOUNT RATE

The choice of the appropriate discount rate for calculating the present value of reserves is problematic in terms of choosing a private or a social discount rate. There are considerations of intergenerational equity, the social opportunity cost of capital related to productivity of (man-made) capital and social time preference. The discussion below addresses some of these issues briefly and relates the choice of discount rates used in studies.

There are two reasons for positive discount rates: (i) social time preference and (ii) productivity of

27. Since there is no direct measure of the "value of capital services" or user cost of capital, a measurement of the user cost is imputed based on economic theory. The imputed nominal user cost of a capital good to its owner is given by:

$$C = rK_I + \delta K_I - \frac{dK_I}{dt}$$

where C is the nominal user cost of capital, r is the rate of interest, δ is the economic depreciation rate and K_I is the value of the capital stock. The last term in the equation is the capital gain or loss. The above equation can be rewritten as:

$$C = K_I(r - \dot{P}_I + \delta)$$

where the "real" rate of interest is $(r - P_I)$, discounting the nominal interest rates by the expected rate of inflation.

capital (i.e. diverting resources for investment rather than consumption). However, discounting appears to be inconsistent with the concept of sustainable development since the higher the discount rate, the lower the importance attached to the future and the conserving of the natural capital stock (Pearce and Turner, 1990). While some environmentalists argue that the only proper discount rate is a zero discount rate, Pearce and Turner (1990) suggest that a choice between zero per cent and 12 per cent. However, this does not solve the problem of by how much the discount rate should be lowered.

Although high interest rates may shift the cost burdens forward to future generations, they also decrease the rate of investment in exploration and development as well as in other types of investment. Since natural resources are required for investment, the demand for natural resources is generally less during periods of high discount rates.

Adelman (1986b) focussed on what rate to discount the flow of revenues from petroleum-producing assets in order to calculate a present value of the resource. The national or "social" discount rate on oil and gas properties owned or taxed by an industrialized country should not be more than 10 per cent (for the 1972-1982 period). But a nation with a highly diversified portfolio, the discount rate cannot be much lower. Below are some examples of the cost of capital from different sources:

Discount Rates in the Oil and Gas Sector

Source	Years	Rate
Watkins (1986): private oil and gas producers' discount rate	1972 1982	9.6% (real) 9.3% (real)
Bank of Canada: long-term corporate bond rate	1972 1982	6.4% (real) 8.9% (real)
AERCB: weighted average cost of capital, 30/70 debt/equity ratio	1989	22% (nominal) 17% (real)

Adelman (1986b) suggests discounting future income streams at about 10 per cent (i.e. 2 percent riskless and 8 per cent premium) since the capital market would supply no equity funds at a lower rate. Adelman (1986b, p.324) relates the issue of discount rates to the Hotelling principle.[28]: "the discounted net return from extracting a mineral unit from a given deposit in any year must equal that in any other year, which in then equals ***any*** return from a holding with equal risk." The Hotelling principle does not require that paradigm of net prices rising at all, at any rate. Mineral scarcity is the result of conflicting forces: diminishing returns versus increasing knowledge. Therefore, the discount rate for the mineral industries which incorporates price risk should be in the normal commercial range.

When considering intergenerational equity when determining the rate of depletion on a non-renewable asset, a zero discount rate of time preference is considered the more appropriate discount rate rather than the sue of today's rate of time preference or the rate of interest used in the capital markets. However, for most applications to various government energy agencies there are no inter-generational considerations since most production profiles are 10 to 15 years (AERCB, 1990). If one views Alberta's Heritage Savings Trust Fund (AHSTF) as one of creating man-made assets funded by the depletion of energy resources, one could view the fund as a source of tangible assets for future generations. The average yield on the assets in the fund might represent a good approximation of Alberta's social discount rate. The average real rate of return for the AHSTF over the 1978 to 1989 period yielded 4.8 per cent. (Smith, 1991).

Since government expenditures are financed by taxes levied on corporations and individuals, government expenditures displace private investment and private consumption. The value of public investment should be at least as valuable as alternative expenditures that are foregone in the private sector. Funds raised by the government under its own taxation laws is about a 50/50 split between corporate-sourced and consumer-sourced public revenues. This suggests an implicit weighted average "social discount (nominal) rate" of 13 per cent in 1988-89.

But should interest rates reflect the opportunity cost of (both man-made and natural) capital? Long-term corporate bond rates have been used extensively in other studies (Copithorne, 1979; Eglington and Uhler, 1986; and McLachlan, 1990). The discount rate should reflect the return from alternative investments and not necessarily the social discount rate. It is the use of private discount rates rather than social discount rate which govern investment decisions. Several real rates of discount are used in this study including constant rates of 0 and 10 per cent and a long-term corporate bond rate.

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28. Mineral prices less extraction costs must rise at the relevant rate of interest which is assumed to be at riskless discount rates.

11.0 CURRENT AND PROPOSED TREATMENT OF NATURAL ASSETS IN THE CNBSA

Several methods of monetary valuation of oil and gas reserves have been proposed in the literature. In the United Nation's SNA Handbook on Integrated Environmental and Economic Accounting (1990), opening and closing stocks of proven reserves are valued by discounting future net returns (p. 149). **Market** values are the discounted flow of future market prices less exploitation costs.

In the present accounts of the United Nation's SNA, when an exploitable resource such as oil is extracted and sold, only the direct cost associated with its extraction, including labour, are deducted from its market value and the difference is treated as the gross operating surplus. Net operating surplus is less depreciation of man-made capital.

11.1Valuation of Tangible Produced Assets

In the CSNA, assets are normally taken into account if they have a market value. This market value is either the actual market value of an asset or the present value of future returns. In economic terms, the market value of capital goods should reflect the market's assessment of relative present values of future net income streams (Statistics Canada, A User Guide, Catalogue 13-589, 1989). However, because of data limitations market values are difficult to obtain for most of the non-financial assets in the Canadian National Balance Sheet Accounts (CNBSA). Various methods are used to serve as a proxy for market value such as the perpetual inventory method to calculate the value of machinery and equipment and structures and consumer durables or imputations for non-agricultural land. The calculation of capital consumption is based on the straight-line method of depreciation.[29]

11.2 Treatment of Expenditures for the Petroleum Industry in the CSNA

This section describes specifically types of expenditures reported by the petroleum industry in Canada and their current treatment in the CSNA.

29. Revisions to the SNA (United Nations, 1991) recommend the straight-line method because of its simplicity and because in the discounted present value of the remaining future earnings from the use of the asset in production may be expected to be approximately constant from period to period in many cases.

The following expenditures are considered part of capital formation in the CSNA and represent the fixed capital stock for the petroleum industry in Canada:

- exploration drilling
- development drilling
- production facilities
- non-production facilities
- enhanced recovery projects
- natural gas processing plants
- other expenditures
- capital expenditures by drilling contractors

Detailed descriptions of these expenditures are presented in Statistics Canada, Exploration, Development and Capital Expenditures from Mining and Petroleum and Natural Gas Wells (Catalogue 61-216).

Other expenditures reported by the petroleum industry are:

- geological and geophysical expenditures
- land acquisition and rental costs
- royalties
- operating expenses

Data for these expenditures used in this study were obtained from Statistics Canada, The Crude Petroleum and Natural Gas Industry (Catalogue 26-213). The current treatment in the National Accounts of these expenditures is reported below.[30]

Geological and geophysical expenditures are not considered part of capital formation in the National Accounts.[31] In the calculation of corporate profits before taxes for the NIEA (i.e. "base profits"), these expenditures are charged to current operations.

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30. For this study we calculate the value of economic rent (corporation profits) using the data from the Statistics Canada publications already cited. Since 1965, the NIEA obtains corporation profits and adjustments to those profits from Corporation Financial Statistics (Catalogue 61-207) and Corporation Taxation Statistics (Catalogue 61-208).

31. These costs are excluded from capital formation in National Accounts since these costs do not give rise to tangible assets.

Land acquisition and rental costs in the CPA Statistical Yearbook and Statistics Canada, The Crude Oil and Natural Gas Industry (Catalogue 26-213) include payment to the Alberta Government for the acquisition rights to explore for oil and gas and to develop reserves, and rental fees are payments made annually by the industry to continue production. According to Eglington and Uffelmann (1983), these rental fees should be netted out because they relate to production and as such are considered operating expenses.[32] Exploration and production rights are acquired by bidding for them. Exploration rights may also be transferred into production rights without bidding. These bonus payments represent part of the economic rent on the natural resource (Eglington and Uffelmann, 1983). The economic cost of a resource from society's point of view is the opportunity cost of using that resource (in this case, land containing subsoil assets) in an alternative activity. Land used in petroleum activities does not have an opportunity cost because there are alternative uses for the land while mineral production occurs (e.g. agriculture). Therefore, land acquisition costs do not represent "social costs" and should be considered part of economic rent, Eglington argues.

In the CNBSA, the land category (1800) includes resource rights (Statistics Canada, Financial Flow and National Balance Sheet Accounts, Catalogue 13-214). There is some debate on how resource rights should be treated in the accounts: as an operating expense, as an intangible asset or as part of the economic rent that is mostly captured by governments. In the development of integrated environmental accounts by Bartelmus et al (1991), they suggest that the framework should measure the implication of environmental factors for production, value-added, expenditures and tangible wealth. They treat exploitation rights as intangible assets and are excluded from their environmental accounts. Landefeld and Hines (1985) also suggest that bonus payments should be treated as an investment and be depreciated over the life of the well.

Land costs and rentals are treated in two ways: as an intangible asset or as part of the economic rent. The appropriate method of valuing bonus and rental payments when they are treated as an intangible asset has not been included in this study. An intangible asset approach may be appropriate for the one-time bonus payments but rental payments which represent a stream of rent (income) to governments should probably be treated in a similar way to royalties and not as an intangible asset. For simplicity, we have treated both bonus and rental payments together. Table 14 shows the values of the bonus and rental payments in Alberta.

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32. Rental fees and royalties associated with leases may also be considered rental incomes to the owner of the leased land. Bonuses are treated as the purchase of an asset of "land".

Table 14: Land Acquisition Cost and Rentals in Alberta (millions of dollars)

Year	1. Statistics Canada Retention Costs[1]	Land Sites	Land Acquistion[2]	Total Expenditure[3]	2. CPA Bonuses	Land Rentals	Total Land Costs
1947	..	..	..	..	0.0	7.5	7.5
1948	..	..	..	..	3.1	8.9	12.0
1949	..	..	..	..	19.8	12.2	32.0
1950	..	..	..	..	36.2	15.8	52.0
1951	..	..	..	..	15.1	17.4	32.5
1952	..	..	..	..	22.4	21.1	43.5
1953	..	..	..	..	22.8	24.2	47.0
1954	..	..	..	..	64.9	29.1	94.0
1955	..	..	..	..	62.4	30.6	93.0
1956	..	..	..	..	72.6	29.9	102.5
1957	..	..	..	..	70.3	34.2	104.5
1958	..	..	..	..	75.6	12.4	88.0
1959	..	..	..	..	73.9	35.1	109.0
1960	..	..	..	..	55.9	35.1	91.0
1961	40.5	0.0	44.9	85.4	45.8	41.7	87.5
1962	48.6	0.0	33.2	81.8	41.7	42.3	84.0
1963	42.9	0.0	46.9	89.8	54.9	37.1	92.0
1964	46.1	0.0	85.7	131.8	95.2	39.8	135.0
1965	71.1	0.6	122.0	193.7	141.7	56.0	197.7
1966	70.1	1.2	99.9	171.2	114.6	55.4	170.0
1967	72.1	0.8	88.7	161.6	102.7	64.3	167.0
1968	71.6	0.8	93.8	166.2	106.8	67.4	174.2
1969	77.0	1.5	102.5	181.1	119.4	60.2	179.6
1970	90.7	0.9	25.9	117.6	36.9	79.7	116.6
1971	101.2	0.4	24.7	126.2	47.9	78.0	125.9
1972	60.3	1.3	64.1	125.6	53.7	70.7	124.4
1973	61.8	1.1	82.5	145.4	76.3	68.0	144.3
1974	64.3	1.4	93.0	158.6	84.1	73.2	157.3
1975	77.4	2.0	130.4	209.9	106.0	101.9	207.9
1976	83.1	0.5	172.4	256.0	160.2	95.3	255.5
1977	89.4	2.2	590.5	682.0	579.8	100.1	679.9
1978	90.2	8.8	650.3	749.2	603.2	137.3	740.5
1979	106.9	8.3	1037.8	1153.0	996.7	147.8	1144.5
1980	161.0	5.1	1063.5	1229.6	1004.9	171.6	1176.5
1981	132.0	14.8	589.3	736.1	588.5	132.8	721.3
1982	131.7	0.0	334.0	465.6	334.0	131.6	465.6
1983				565.1	429.5	135.6	565.1
1984				790.2	624.2	166.0	790.2
1985				1021.1	796.2	224.9	1021.1
1986				447.3	250.9	196.4	447.3
1987				841.1	688.7	152.4	841.1
1988				676.5	522.8	153.7	676.5
1989				551.7	360.6	191.1	551.7
1990				614.1			

1. Includes producing and non-producing acreage retention costs, bonuses paid for acquisition of freeholder's mineral rights; land department salaries and overhead
2. Permit fees and acquisition costs; includes bonuses, legal fees and filing fees
3. After 1983 data is aggregated

Source: Statistics Canada: The Crude Petroleum and Natural Gas Industry, Catalogue 26-213; and Canadian Petroleum Association Statistical Yearbook

The data for revenues, exploration and development expenditures and operating costs are compiled from Statistics Canada, Exploration, Development and Capital Expenditures for Mining and Petroleum and Natural Gas Wells (Catalogue 61-216) and Statistics Canada, The Crude Petroleum and Natural Gas Industry (Catalogue 26-213). Although the expenditures are similar in both publications, differences occur due to reporting on a calendar or fiscal year and the fact that Catalogue 61-216 does not report geological and geophysical expenditures). Table 15 compares the data from the two sources.

Exploration and development expenditures are reported for both oil and gas reserves. Allocation of expenditures for each year was done by calculating exploration oil intent and development intent ratios based on the number of successful metres drilled. Operating costs are allocated to oil and gas production on the basis of the number of operating oil or gas wells to the total number of operating wells.

11.3 Asset Balances of Net Tangible Assets

The UN SNA Handbook (1990) has developed the following method of deriving the monetary value of economically non-produced natural assets, namely proven subsoil assets. The basic formula for the value of subsoil assets from year to year is:

$$\text{closing stock} = \text{opening stock} + \text{exploration costs} + \text{volume changes due to extraction and reserve additions} + \text{market price changes}$$

All components are valued at market price (i.e. discounted value of future net returns from future market prices less exploitation costs) except for the treatment of exploration costs and natural resource depletion. Depletion of subsoil assets is estimated at current market values, that is current market price less "exploitation costs". Table 16 provides an outline of a proposed treatment of monetary accounts for subsoil assets (UN SNA Handbook, 1990). While the treatment of certain expenditures does not conform to the CSNA, the table provides an outline for reporting subsoil asset values. Some of these differences are discussed below.

Table 15: Exploration and Development Capital Expenditures in the Petroleum and Natural Gas Industry in Alberta (millions of dollars)

	1986	1987	1988	1989
Exploration Drilling				
STC 61-216	1031.9	911.7	1097.3	817.2
STC 26-213	1021.3	1010.8	1089.4	838.0
Development Drilling				
STC 61-216	982.1	964.6	1150.3	754.0
STC 26-213	983.1	883.1	1164.9	686.5
Production Facilities				
STC 61-216	719.1	696.3	860.4	902.8
STC 26-213	773.7	679.6	912.1	942.0
Non-Production Facilities				
STC 61-216	83.6	x	78.5	106.3
STC 26-213	79.3	88.8	93.1	81.4
Enhanced Recovery Projects				
STC 61-216	305.9	258.9	355.7	339.1
STC 26-213	229.4	223.3	351.2	345.2
Natural Gas Plants				
STC 61-216	178.5	134.1	223.5	300.8
STC 26-213	181.0	162.3	207.8	363.5
Other Expenditures				
STC 61-216	--	x	0.0	26.7
Oil and Gas Drilling Contractors	19.5	9.8	12.7	10.4
STC 61-216				
TOTAL				
STC 61-216	3301.1	3041.0	3,765.7	3,246.9
STC 26-213	3267.7	3048.0	3818.5	3256.6

x confidential -- too small to be shown

Source: Statistics Canada: Exploration, Development and Capital Expenditures for Mining and Petroleum and Natural Gas Wells, Catalogue 61-216; Statistics Canada: The Crude Petroleum and Natural Gas Industry, Catalogue 26-213.

Table 16. Asset Balances of Net Tangible Assets

	Total	Economically Non-produced Natural Assets						
		Economically Produced Assets	Economic Non-produced Biological Assets	**Land (Landscape, Ecosystems)**				
				Cultivated	Uncultivated	Subsoil Assets	Water	Air
[1] Opening stocks (market values)						x		
[2] Net capital formation (use of products, market values)						x		
[2.1] Gross capital formation								
[2.2] Consumption of fixed capital						x		
[3] Volume change of natural assets due to economic use (market values)						x		
[3.1] Ecological valuation								
[3.1.1] Quantitative depletion						x		
[3.1.2] Degradation of land (except residuals)								
[3.1.3] Degradation by residuals								
[3.2] Adjustment due to market valuation								
[3.1.1] Quantitative depletion								
[3.2.2] Land use (except by residuals)								
[3.1.3] Degradation by residuals								
[3.3] Other volume changes (change of land use, new finds, new estimates, etc.)						x		
[4] Volume change by natural or multiple causes (market valuation)								
[5] Revaluation due to market price changes						x		
[6] Closing stocks (market values) [1 + 2 + 3 + 4 + 5]						x		

Source: modified after SNA Handbook on Integrated Environment and Economic Accounting (1990)

According to the UN's document (1990, p. 52), exploitation costs should exclude exploration costs. Exploration costs are included as part of "gross capital formation" in Table 16. Gross capital formation normally leads to an increase of produced assets. Exceptions are the "development (exploration, etc.) of subsoil assets". These economic activities are connected with services which should be treated as capital formation of the non-produced natural assets and included as part of the value of the subsoil asset. It is not clear whether or not all exploration and development expenditures should be included as part of the capital formation and why they are included as part of the value of the non-produced subsoil assets.

There appears to be double counting in this treatment of exploration costs, however. If exploitation costs do not contain exploration costs, this suggests that exploration costs are included in the stream of future returns. But exploration costs are also included as part of the value of the non-produced subsoil assets under capital formation. Exploration, development and operating costs should be subtracted from the market price in order to derive the rental value of the resource. Exploration and development expenditures are generally treated as fixed capital formation except for geological and geophysical costs in the CSNA. Whether these costs represent tangible or intangible assets, expenses or whether they represent part of the value of the non-produced subsoil asset is a matter of further discussion.

Monetary values for opening and closing stocks are derived by the discounted value of net returns (future market prices minus all exploitation costs, including a normal rent of capital[33]). Market valuation is also applied to volume and price changes. However, an ecological valuation is used to estimate the value of extraction (or depletion) of these assets and then adjusted to market values. The ecological valuation could comprise the costs for maintaining the level of natural capital (e.g. through substitution) or the level of total capital (e.g. man-made and natural capital). This method of valuation appears to be similar to the "user cost" approach suggested by El Serafy (1989). The market value for the depletion of the asset reflects the net price of the depleted assets (current price minus exploitation costs). This suggests that the depletion of the asset is valued at its current net price (that is, its "ecological value" adjusted to is market value) while opening and closing stocks and volume and price changes are valued at the discounted value of net returns (Bartelmus et al, 1991).

33. The normal rent of capital refers to the man-made assets which are used for the exploitation of the natural asset (e.g. drilling equipment).

In this study, reconciliation tables are developed similar to those developed by Repetto et al (1989) for petroleum resources in Indonesia (see Section VIII). While Repetto et al use a net price approach to value the reserves, the UN approach is based on a discounted value with various methods of valuing depletion.

12.0 THE VALUATION OF OIL RESERVES IN ALBERTA

The focus of this study is to derive a methodology to value oil and gas reserves in Canada. The results from different methods of valuation tabulated for conventional oil and natural gas reserves in Alberta are presented. These results are preliminary and require further refinement in order to incorporate these values into CNBSA.

The three methods of valuation presented below are:

1. Net Price Method
2. Present Value Method
3. Replacement Cost Method

12.1 Net Price Method

The net price method is based on the assumption that the net price (average price less the (marginal) costs of extraction, development and exploration, including physical capital costs) will rise at a rate equal to the rate of return on alternative investments (rate of interest) as explained by the "Hotelling r-per cent" rule (Landefeld and Hines, 1985). The net price method is a special case of the present value where on average long-run market equilibrium will occur (i.e. the net price will rise at the rate of alternative investments) and the rise of the net price will exactly offset the discount rate. The implications of this assumption has been discussed in an earlier section and are discussed by Gervais (1990).

The net price value is calculated by the method outlined by Landefeld and Hines (1985): the total revenue from extraction, less the variable (operating) cost and dividing the difference by the total quantity produced in period t. This net price per unit is multiplied by the quantity of remaining reserves to obtain an estimate of the total value of oil and gas reserves. The "natural resource" component of the total value is derived by subtracting the current replacement cost value of net physical capital stock employed in the extraction of oil and gas. Both Landefeld and Hines (1985) and the Japanese values of subsoil assets (Blades, 1980) estimate the gross operating surplus and deduct the net value of the fixed assets of the industry.

Also the net price is calculated from revenues less operating costs and the opportunity cost of man-made capital (i.e. return to capital and depreciation charge). This is consistent with the definition of the opportunity cost of capital outlined by Branson (1972) and Copithorne (1979), already discussed in a earlier section.

Repetto et al (1989) also use the net price method to calculate the value of petroleum reserves in Indonesia. Factor costs of developing, extracting and transporting the oil are estimated for the period by dividing the total annual expenditures for exploration and development by total production.[34] The net price or resource rent is the difference between unit revenues and costs.

Smith (1991) has calculated estimates for crude oil and natural gas reserves in Alberta using the net price method which is similar to Repetto et al. The net rent per unit is the difference between the average wellhead price less the "cost of production". This cost includes exploration, development and operating costs, including a normal return to the required physical and financial capital. Since marginal costs are not generally available Smith (1991) also conducts a sensitivity analysis where it is assumed that the marginal cost is equal to 1.33 times of the average cost. The normal return to capital is calculated as the cost of equity (7 per cent plus the inflation rate in each year times equity investment in oil and gas wells).[35]

It should be noted that these methods differ from those discussed above in that fixed capital expenditures are not capitalized but expensed. The net price method outlined by Landefeld and Hines (1985) conforms most closely to the treatment of expenditures in the CSNA.

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34. Operating costs appear to have not been included. Exploration costs are treated as current production costs. It is assumed that development costs are treated in the same manner although Repetto et al do not state it.

35. Smith (1991) uses the equity investment reported in Statistics Canada, Corporation Financial Statistics (Catalogue 61-207). These data are reported at the corporation level, not the establishment level, therefore include downstream operations. These data are reported on a national basis, not provincially.

Tables 17 a and b present the value of oil and natural gas reserves in Alberta using the net price method. Two values have been calculated: including and excluding land acquisition costs as a variable cost. Variable costs are defined as operating costs and geological and geophysical costs, including/excluding land acquisition costs. In National Accounts, land costs are not considered part of capital formation as discussed above. Eglington and Uffelmann (1983) argue that these costs are part of the economic rent and do not represent social costs, therefore should be part of the net price. These costs are not considered part of the physical costs of exploration and development of oil and gas reserves but rather a component of oil and gas revenues (transfer payments) to government (Helliwell et al, 1989; Adelman, 1986). Again, the treatment of land costs is a issue for discussion.[36]

The values in Table 17 a and b reflect decreasing quantities of remaining established crude oil reserves in Alberta since 1974 and significant increases in oil prices since 1973 with the collapse of oil prices in 1986. The reserve value for natural gas has decreased since 1982, again reflecting decreasing stock and the collapse of natural gas prices in 1986.

12.2 Present Value Method

As discussed above, the preferred method of valuing natural resources is to estimate the present value of future net income expected from the extraction of the natural resource. The Securities and Exchange Commission and Canadian Securities Commissions require that companies report the present value of future net cash flows from estimated production of proved reserves. The United Nation's Statistical Office has suggested using this method of valuation. The present discounted value method is outlined by Landefeld and Hines (1985) and by Soloday (1980) for oil and gas reserves in the United States. Japan and Hungary have reported present values of their subsoil assets (Blades, 1980). Uhler and Eglington (1986) provide reserve prices based on a present value approach.

The present value of oil reserves is calculated from the equation below:

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36. At present Category 1800 in the CNBSA does not include these costs and intangible assets are not included in the CNBSA.

Table 17a : Monetary Value of Remaining Established Reserves of Crude Oil in Alberta Based on the Net Price Method (millions of dollars)

Year	[1]	[2]	[3]
1961	5259.5	3241.0	..
1962	5095.4	2946.0	1636.0
1963	6016.9	3574.0	1310.0
1964	10154.1	5464.0	2429.0.
1965	10447.3	5176.0	2414.0
1966	11586.9	5210.0	2708.0
1967	11514.3	4962.0	263.0
1968	13219.3	6168.0	599.0
1969	13503.6	6414.0	1630.0
1970	14653.3	8465.0	5537.0
1971	15575.3	10009.0	7314.0
1972	15305.9	11033.0	8015.0
1973	18212.2	15202.0	12432.0
1974	31267.0	27074.0	23956.0
1975	36756.9	30874.0	25586.0
1976	38939.5	32735.0	22216.0
1977	45726.2	39832.0	26445.0
1978	51902.1	45674.0	24874.0
1979	52894.6	47147.0	33166.0
1980	57440.8	48600.0	38906.0
1981	67984.4	53025.0	27796.0
1982	84083.1	66916.0	47884.0
1983	111124.8	95985.0	80508.0
1984	111460.9	95955.0	85659.0
1985	112727.8	95218.0	75514.0
1986	43286.0	25489.0	16662.0
1987	55879.4	36911.0	33957.0
1988	27454.1	9471.0	6819.0
1989	34652.8	15548.0	..

[1] Based on methodology by Landefeld and Hines (1985): based on gross operating surplus, net fixed capital stock valued at replacement cost with total land costs included as part of economic rent
[2] Net price equals revenue less operating costs, return on capital and depreciation charge
[3] Results from Smith (1991)

Source: National Accounts and Environment Division, Statistics Canada

Table 17b :Estimates of the Economic Value of Natural Gas Reserves in Alberta Based on the Net Price Method (millions of dollars)

Year	[1]	[2]	[3]
1961	1887.4	-1207.2	..
1962	2777.8	415.4	-238.0
1963	5044.0	2604.1	-161.0
1964	5865.9	3265.0	463.0
1965	6645.9	3590.5	641.0
1966	7022.0	3485.7	573.0
1967	8416.3	4181.0	-93.0
1968	9377.1	4190.0	225.0
1969	8127.7	3056.7	1273.0
1970	7389.3	1965.9	-189.0
1971	6271.0	814.1	-363.0
1972	6714.9	992.9	0.0
1973	10227.2	2353.1	-196.0
1974	23729.9	12599.6	2982.0
1975	42859.5	29443.7	17645.0
1976	62715.9	46055.3	33772.0
1977	77265.1	58313.1	47261.0
1978	81401.1	57839.0	51444.0
1979	104369.9	71056.2	45784.0
1980	157923.4	99381.0	82593.0
1981	161582.3	93411.3	54829.0
1982	210824.7	129447.9	71694.0
1983	186351.1	108127.8	88898.0
1984	193509.5	124553.1	99934.0
1985	177658.7	117586.6	84650.0
1986	115848.8	52674.9	45850.0
1987	81655.9	17177.4	20491.0
1988	55118.7	8240.3	13606.0
1989	55232.8	1126.2	..

[1] based on methodology by Landefeld and Hines (1985): based on gross operating surplus, net fixed capital stock valued at replacement cost with total land costs included as part of economic rent

[2] Net price equals revenue less operating costs, return on capital and depreciation charge

[3] Results from Smith (1990)

Source: National Accounts and Environment Division, Statistics Canada

$$PV_0 = \sum_{t=0}^{T} \frac{N_t Q_t}{(1+r)^t}$$

where N_tQ_t is the expected future income flow generated by the asset (i.e. gross (or net) operating surplus) which is discounted at nominal or real interest rates, r, for the life of the asset, T. Landefeld and Hines (1985) define N_t as total per unit less unit costs of extraction, development and exploration over period t.

In our analysis, the net present value has been calculated several ways. Generally, the methods employed have tried to conform with the national accounting procedures used in the CSNA as well as employing other accounting procedures used in other studies. The present value of oil and natural gas reserves is calculated from the equation presented above where N_t is defined as the average wellhead/field gate price less operating costs and geological and geophysical expenditures, depreciation on man-made capital and "normal return to capital" on K_t, the net capital stock of the exploration drilling and total development expenditures valued at its replacement cost.

Also from the literature, the net present value has been calculated by treating capital formation as intermediate inputs instead as capital stock, in similar manner as Repetto et al (1989) and Landefeld and Hines (1985).

Discount rates of 0 and 10 per cent and a long-term corporate bond rates in real terms have been used to calculate various present values. Landefeld and Hines (1985) use a constant real 10 per cent discount rate because it represents the rate of return on private investment before taxes and after inflation. The National Energy Board (NEB) employs a 15 per cent real rate before taxes, royalties and land costs to approximate the "hurdle rate" used by investors (Bowers and Kutney, 1990). Long-term bond rates are used by Eglington and Uffelmann (1983) and McLachlan (1991) in determining the present value of replacement costs of oil and gas reserves in Alberta. The appropriate discount rate is the subject of much debate in the literature as previously discussed in Section 10.

The method of calculation follows closely the method used in the Reserves Recognition Accounting method where year-end prices and costs (in real terms) are assumed over the life of the remaining reserves. The estimated operating surpluses expected over the life of the remaining reserves are converted to present~~s~~ values using difference discount rates.

Also, the present value of reserves were calculated using "perfect knowledge' of revenue and cost data. However, price, operating cost and annual production forecasts for crude oil were calculated from a 4-year moving average projected to 1998 in order to forecast future income streams. In recent years, annual production rates in Alberta have remained relatively stable so estimating future annual production is relatively certain. However, world prices and operating costs are more volatile and present a problem in our calculations. For natural gas, projections were made to 2007 using a 4-year moving average of the operating surplus.

Tables 18 a and b present the present value of oil and natural gas reserves discounted at real long-term corporate bond rates using various approaches. In the case of real discount rates, a GDP price deflator ~~defaulter~~ was used to convert the data to 1986 dollars. Deflating the "gross/net operating surplus" presents a problem in the petroleum industry. Capital stock price indices indicate that prices for fixed capital increased at a rate higher than inflation of the economy while the raw material price index for crude oil was decreasing below the rate of inflation of the economy in the late 1980s. Because we are using "net income" to value crude oil reserves, a GDP deflator was chosen.

12.3 Replacement Cost Approach

In the CNBSA, reproducible fixed assets are valued at ***current market values*** rather than book values or acquisition costs. In economic terms, the relative market valuations of capital goods reflect the market's assessment of the relative present values of future net income streams (Statistics Canada, <u>A User Guide to the CSNA</u>, Catalogue 13-589, 1989). In a perfect market, present values would equal the replacement cost value which would equal the market value. Markets for many capital goods are restricted because they are not frequently traded where prices are being determined. Thus, it is necessary to use alternative measures to derive current valuations. The most common method is the perpetual inventory method at replacement cost.

Table 18a : Estimates of the Economic Value of Crude Oil Reserves in Alberta Based on the Present Value Method (millions of dollars)

Year	[1]	[2]	[3]
1961	1882.2	1873.1	2885.0
1962	1741.5	1845.4	3317.4
1963	2144.9	1937.3	3951.6
1964	2708.3	2418.8	8414.9
1965	2546.7	2513.4	9694.6
1966	2443.3	2487.6	12622.3
1967	2258.7	2485.6	13956.8
1968	2544.1	2433.8	14243.4
1969	2719.4	2537.5	14988.6
1970	3847.9	3400.0	15984.8
1971	5088.2	4339.2	18201.7
1972	6658.3	6154.6	21495.4
1973	10900.1	8792.2	26186.6
1974	20159.2	12121.8	31909.4
1975	20002.5	13735.3	30138.0
1976	21336.9	17341.8	32786.0
1977	25964.9	20919.4	34664.3
1978	29669.2	24079.6	35721.1
1979	35675.5	31479.2	41220.4
1980	33991.2	28910.1	38545.7
1981	32237.5	24785.1	34485.1
1982	40049.8	28367.6	33383.0
1983	59311.6	43454.4	34351.1
1984	55531.1	48493.0	26032.8
1985	57094.9	55280.7	21103.0
1986	16068.8	43293.5	16579.4
1987	26323.9	33902.5	16147.4
1988	6961.6	15173.5	12447.7
1989	11424.6	12167.5	12261.8

[1] Discounted at real long-term corporate bond rate based on year-en prices and costs

[2] Same as [1] except based on a 4-year moving average

[3] Based on "perfect knowledge" of production, prices and costs (until 1980), discounted at real long-term corporate bond rate

Source: National Accounts and Environment Division, Statistics Canada

Table 18b : Estimates of the Economic Value of Natural Gas Reserves in Alberta Based on the Present Value (millions of dollars)

Year	[1]	[2]	[3]
1961	-302.3	-546.3	3313.2
1962	143.2	-355.1	3740.4
1963	1010.2	81.7	4561.6
1964	1305.7	623.3	5218.8
1965	1446.8	1118.6	6209.5
1966	1400.9	1410.2	7145.6
1967	1557.2	1445.3	7273.5
1968	1362.2	1338.5	7147.1
1969	1110.2	1289.4	7557.3
1970	718.6	1149.8	8034.5
1971	359.4	986.3	9330.8
1972	499.2	876.1	11294.8
1973	1231.3	1081.1	14264.5
1974	7034.8	3552.6	18210.1
1975	14484.6	6946.4	18457.8
1976	21588.8	13756.8	20394.0
1977	27718.4	21741.3	21200.7
1978	26981.9	27603.2	21390.7
1979	40063.4	46460.8	24481.6
1980	46587.2	44181.3	23486.9
1981	36981.5	36815.7	20873.0
1982	44084.2	40483.5	19369.6
1983	41913.2	46045.1	17378.0
1984	41607.9	38824.5	13504.8
1985	46488.1	47979.6	10636.2
1986	22997.8	48995.1	7364.0
1987	9195.9	52551.6	7042.9
1988	5018.4	34911.8	7024.3
1989	662.8	14453.6	7474.6

[1] Discounted at real long-term bond corporate bond rate based on year-end prices and costs
[2] Same as [1] except based on a 4-year moving average
[3] Based on "perfect knowledge" of production, prices and costs discounted at real long-term corporate bond rate

Source: National Accounts and Environment Division, Statistics Canada

McLachlan (1990) identifies two distinct concepts for replacement costs for oil and natural gas reserves in Alberta: 1. the first approach matches exploration and development expenditures in a particular year with reserves additions booked in that year and 2. the second approach matches exploration and development expenditure profile related to reserves discovered in a particular year with fully appreciated reserves from that discovery.

Eglington and Uhler (1983) use a "booked reserves" approach (which is similar to McLachlan's first approach) to analyse exploration and development costs in Alberta's oil and gas industry suggesting that this method corresponds more closely to overall economics of reserves creation (i.e. the cost of establishing reserves). The focus of their study is to estimate incremental annual unit costs of adding reserves to a reserves base. Observed costs of replacing oil in the ground include geological and geophysical costs, exploration drilling and development costs.[37] These costs also include the foregone interest on the money invested from the times these various expenditures were made to the date that the (established developed) reserves were booked (Uffelmann, 1985). Eglington and Uffelmann (1983) distinguish between social and private marginal supply costs where private costs include land costs plus the interest foregone on the money invested. Social supply costs exclude land costs since land costs are considered to be part of the economic rent not part of the replacement cost.

While the method of calculating replacement costs using appreciated reserves has been used for natural gas for part of the time series in this present study, it is an area of further research.

Gervais (1990) suggests that acquisition costs may serve as a proxy for the value of natural resources. These costs include exploration and development costs plus land acquisition costs. Gervais suggests also including royalties.

Table 19 presents the results for the value of conventional oil and natural reserves based on replacement costs. In the first calculation, land acquisition costs attributed to exploration and development are included:

37. In the CSNA, geological and geophysical costs are treated as operating expenses. This conceptual difference will not allow direct comparisons of replacement costs with the other methods of valuation.

$$TCBR = LC_{t-3}(1+r_{t-3})^3 + XGG_{t-2}(1+r_{t-2})^2 + XD_{t-1}(1+r_{t-1}) + DC$$

where:
- $TCBR$ = total cost of booked reserves
- XGG = geological and geophysical expenditures
- XD = exploration drilling expenditures
- DC = development costs
- LC = land acquisition and rental costs
- r = long-term bond rate

Total cost of booked reserves is divided by the total number of reserves additions in period t (i.e. discoveries, development and revisions and enhanced oil recovery) to yield a replacement cost per cubic metre of oil reserve added. Then a 5-year moving average is used to average the costs and the booked reserves. A 5-year moving average is also used by Eglington and Uffelmann (1983) and by McLachlan (1990). The unit cost of booked reserves is multiplied by the number of remaining established reserves of crude oil to obtain an economic value of the oil reserves.

Table 19 presents a summary of the estimates of the economic value of crude oil reserves in Alberta derived from the different methods discussed above.

12.4 Discussion

Three methods of monetary valuation are presented in this section. However, each method can be calculated in a number of ways. Table 20 presents the various accounting procedures that are used in various studies on natural resource accounting.

The main issues common to both the net price and present value methods are: (1) capitalizing or expensing some or all of exploration and development expenditures; (2) including or excluding the value of land acquisition cost and rental fees as part of the value of the subsoil asset; (3) using a gross or net "operating surplus"; and (4) including or excluding a return on capital from the value of the subsoil asset. In the case of present value calculations, the choice of a discount rate is important.

Table 19: Estimates of the Economic Value of Crude Oil and Natural Gas Reserves in Alberta Based on Replacement Cost Value

	Crude Oil Reserves		Natural Gas Reserves				
Year	Replacement Cost $per cu m[1]	Total Value millions of $	Replacement Cost $/000 cu m	Replacement Cost $/000 cu m[3]	Total Value millions of $	Replacement Cost $/000 cu m[4]	Total Value millions of $
1963	3.84	2323.6	4.65	2.25	2089.3	..	..
1964	3.34	3097.0	4.81	2.42	2396.0	..	..
1965	3.12	3017.4	4.91	2.51	2649.9	..	..
1966	2.88	3094.3	3.38	2.64	2833.4	..	..
1967	2.74	3106.3	3.50	3.00	3358.4	..	..
1968	2.41	2921.3	2.73	2.84	3471.0	..	..
1969	3.54	4331.5	3.39	3.12	3970.5	..	..
1970	4.07	4916.7	5.47	3.72	4753.3	..	..
1971	6.32	7417.1	7.73	5.18	6609.0	..	..
1972	7.88	8874.1	10.45	6.02	7643.2	..	..
1973	12.47	13114.8	11.19	6.26	8742.5	..	..
1974	14.24	14401.2	12.93	7.38	10972.5	11.16	16592.0
1975	21.79	20720.9	19.46	8.14	11816.0	12.13	17604.2
1976	17.67	15395.0	19.85	8.65	12982.8	11.28	16936.1
1977	18.78	15585.4	18.16	9.34	14654.7	12.51	19623.6
1978	16.36	12996.6	20.49	10.83	18036.0	14.22	23685.1
1979	22.27	16928.2	24.92	14.20	24402.3	19.89	34183.8
1980	28.40	20442.4	23.47	19.51	34081.8	24.62	43013.5
1981	47.42	33004.4	28.83	25.18	45199.3	35.77	64221.9
1982	108.55	70491.9	35.66	29.72	55072.2	54.66	101096.7
1983	109.77	72205.5	49.80	30.45	55604.7	61.13	111634.5
1984	118.45	75888.8	60.94	30.86	55503.2	62.39	112196.5
1985	113.42	73588.8	62.80	33.76	59702.3	63.78	112787.9
1986	114.32	72559.8	73.17	34.16	58754.0	54.83	94320.3
1987	67.41	41374.3	[2]	42.42	70068.1	40.97	67675.1
1988	77.22	45784.0		50.98	82979.3	33.81	55038.1
1989	86.58	48529.4		53.50	88258.0	..	..

[1] Includes all exploration and development expenditures and land bonuses; data is time-lagged and a 5-year moving average is used; unit costs are derived from booked reserves

[2] Replacement cost is infinite because gross reserve additions are 0 for 1987

[3] same as [1] except unit costs are divided by 3-year moving average of reserve additions

[4] same as [1] except unit costs are divided by "fully appreciated reserves" (after McLachlan, 1990)

.. not available

Source: National Accounts and Environment Division, Statistics Canada

Table 20. Proposed methods for estimating the monetary value of crude oil and natural gas reserves.

1. Net Price

a) expense all capital costs (e.g. exploration and development) during the period incurred (after Repetto et al, 1989; and Smith, 1991)

or

capitalize exploration and development expenditures and subtract gross/net capital stock to derive value of the natural resource (after Landefeld and Hines, 1985)

b) use gross "operating surplus" to determine the total value of the reserves (similar to Repetto et al, 1985)

or

use net "operating surplus" (i.e. G.O.S. less depreciation on man-made capital and return on capital) as suggested by Ward (1982) and Bartelmus et al (1991)

c) include land acquisition costs and rental fees as part of economic rent

or

exclude land acquisition costs and rental fees and treat these costs as an intangible asset

2. Net Present Value

a) all of the above choices apply to the calculation of net present value

b) discount rate: 0, 5, 10, 15% real rates, constant over the remaining life of the reserves and over the time series; using constant dollar income streams to calculate present value

or

nominal long-term corporate bond rates (with or without a 40% premium), constant over the remaining life of the reserves but changing in each year of the time series; using current dollar income stream

c) forecast future expected income streams using a 3- or 4-year moving average of operating profit

or

for natural gas, use a 3-year moving average of net income per unit times the 4-year moving average of production

3. Replacement Cost

a) present value 5-year moving average of time-lagged exploration and development costs over booked reserve additions in the year costs are incurred (after McLachlan (1990) and Eglington and Uffelmann (1983)

or

present value 5-year moving average of time-lagged exploration and development costs over "fully appreciated" reserve additions (after McLachlan (1990) and Pasay (1987)

b) marginal/average finding costs from models developed by Helliwell et al (1989), Livernois (1988), Devarajan and Fisher (1982) and Lasserre (1985)

There is some debate whether or not replacement costs (i.e. discovery cost +/- rent on exploratory prospects) represent a good approximation for rent. Table 20 outlines the different models presented in the literature. Especially important are those studies for the replacement costs calculated for oil and natural gas reserves in Alberta. The use of the moving averages and time-lagged data divided by booked or fully appreciated reserves are compared to other models presented in the literature. It was found that the former provided the most reliable time series.

13.0 RECONCILIATION TABLES

Reconciliation tables for both the physical and monetary accounts for oil and natural gas are presented in Table 21 based on the net price methods, net present value method and the replacement cost method. The tables also include the net price per unit calculated by Smith (1991) for oil and natural gas reserves in Alberta.[38]

Our reconciliation accounts follow the accounts developed by Repetto et al (1989) for the Indonesian petroleum resources with opening and closing stock, net changes (additions/re-evaluation less depletion of the stock) and revaluation in the monetary accounts due to market price changes ((np_1-np_o) x opening stock where np is the "net price").

Table 22 presents the Asset Balances for subsoil assets in monetary units developed in the *UN SNA Handbook on Integrated Environment and Economic Accounting* (1990) and Bartelmus et al (1991). It differs from the tables presented above in the following ways:

(1) opening and closing stocks and volume changes due to reserve additions/revisions are valued at market values (i.e. discounted value of future market prices less exploitation costs); (2) depletion of resources are valued at some imputed ecological value and adjusted to a current (not discounted) market value; and (3) net capital formation (i.e. exploration costs) are included as part of the value of the non-produced natural asset. Details of the asset balances have been presented in the previous section.[39]

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38. There are several differences in methodology between Smith's and our calculations. For example, Smith uses physical data from the CPA and allocates production and capital costs between oil and gas based on share of value of sales and fieldgate price for natural gas.

Table 21. Summary Physical and Monetary Accounts for Established Reserve Stocks for Crude Oil and Natural Gas in Alberta

	CRUDE OIL RESERVES	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
	PHYSICAL ACCOUNTS (millions of cubic metres)														
[1]	Opening Stocks	525.0	557.6	575.6	605.4	926.7	965.7	1074.2	1132.9	1212.8	1222.6	1207.9	1173.6	1126.0	1052.0
[2]	Additions														
[3]	Discoveries	1.7	2.9	14.6	9.5	28.8	89.1	57.2	62.0	40.5	8.4	14.0	10.6	5.1	4.3
[4]	Development and Reevaluation	31.5	21.8	12.6	88.2	42.8	13.5	15.7	14.8	−44.5	−7.8	8.7	−5.8	−6.0	3.3
[5]	Enhanced Oil Recovery	24.5	19.9	29.2	250.8	−2.4	38.3	22.2	42.9	58.5	36.1	−0.8	14.6	10.2	30.8
[6]	Depletion	25.1	26.2	26.8	27.9	29.2	32.0	36.6	39.8	44.4	51.7	56.4	67.4	83.3	79.0
[7]	Net Change	32.6	18.4	29.6	320.6	39.6	108.9	58.5	79.9	10.1	−14.6	−34.5	−47.4	−74.0	−40.6
[8]	Closing Stock	557.6	575.6	605.4	926.7	965.7	1074.2	1132.9	1212.8	1222.6	1207.9	1173.6	1126.0	1052.0	1011.5
	UNIT VALUES ($/cubic metre)														
[9]	Average Wellhead Price	14.82	14.28	15.81	16.09	16.14	16.27	16.06	16.14	16.00	16.27	17.84	17.92	21.83	36.33
[10]	Production and Capital Costs	9.01	9.16	9.91	10.19	10.78	11.42	11.70	11.05	10.75	9.26	9.31	8.12	7.38	9.56
[11]	Net Price	5.81	5.12	5.90	5.90	5.36	4.85	4.36	5.09	5.25	7.01	8.53	9.80	14.45	28.77
	MONETARY ACCOUNTS (millions of $)														
[12]	Opening Stocks		3240	2947	3572	5468	5178	5210	4939	6173	6420	8467	10011	11035	15201
[13]	Additions														
[14]	Discoveries		15	86	56	153	432	249	316	213	59	119	106	74	115
[15]	Development and Reevaluation		112	74	520	228	65	68	75	−234	−53	74	−55	−87	88
[16]	Enhanced Oil Recovery		102	172	1480	−13	186	97	216	307	253	−7	145	147	625
[17]	Depletion		134	158	165	157	155	160	203	233	362	481	661	1204	2115
[18]	Net Change		94	175	1892	212	528	255	407	53	−104	−294	−465	−1089	−1087
[19]	Revaluation		−365	449	0	−500	−493	−526	827	194	2152	1838	1490	5238	12961
[20]	Closing Stock	3240	2947	3572	5468	5178	5210	4939	6173	6420	8467	10011	11035	15201	27078
	NATURAL GAS RESERVES	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
	PHYSICAL ACCOUNTS (billions of cubic metres)														
[21]	Opening Stocks	878.6	879.9	912.1	928.2	992.0	1057.6	1072.6	1119.1	1223.6	1273.4	1279.4	1278.3	1269.1	1396.6
[22]	Additions														
[23]	Discoveries	9.6	6.9	3.1	7.2	11.3	2.1	24.3	15.3	18.6	7.6	4.8	12.5	7.8	6.6
[24]	Development and Reevaluation	3.7	41.0	32.7	78.7	78.4	38.6	49.6	119.3	68.9	38.7	40.6	32.8	175.6	138.4
[25]	Depletion	11.9	17.6	19.6	22.1	24.2	25.5	27.5	30.0	37.8	40.1	48.5	52.4	56.0	57.0
[26]	Net Change	1.4	32.3	16.2	63.8	65.5	15.2	46.4	104.6	49.7	6.2	−3.1	−7.1	127.4	90.0
[27]	Closing Stock	879.9	912.1	928.2	992.0	1057.6	1072.6	1119.1	1223.6	1273.4	1279.4	1276.3	1269.1	1396.6	1486.5
	UNIT VALUES ($/000 cubic metres)														
[28]	Average Composite Wellhead Price	6.08	6.63	8.53	9.14	9.59	10.56	11.71	12.21	10.35	10.64	9.70	10.86	13.16	23.37
[29]	Production and Capital Costs	7.45	6.17	5.72	5.85	6.20	7.31	7.97	8.79	7.95	9.10	9.06	10.08	11.50	14.89
[30]	Net Price	−1.37	0.46	2.81	3.29	3.39	3.25	3.74	3.42	2.40	1.54	0.64	0.78	1.66	8.48
	MONETARY ACCOUNTS (millions of $)														
[31]	Opening Stocks		−1205	420	2608	3264	3585	3486	4185	4185	3056	1970	817	990	2346
[32]	Additions														
[33]	Discoveries		4	9	24	38	7	91	52	45	12	3	10	13	73
[34]	Development and Reevaluation		19	92	259	266	125	186	408	165	60	26	26	295	1174
[35]	Depletion		8	55	73	82	83	103	103	91	62	31	41	94	483
[36]	Net Change		15	46	210	222	49	174	358	119	10	−2	−6	214	763
[37]	Revaluation		1610	2143	446	99	−148	526	−358	−1248	−1095	−1151	179	1142	9497
[38]	Closing Stock	−1205	420	2608	3264	3585	3486	4185	4185	3056	1970	817	990	2346	12600

Source: National Accounts and Environment Division, Statistics Canada

Table 21. Summary Physical and Monetary Accounts for Established Reserve Stocks for Crude Oil and Natural Gas in Alberta

CRUDE OIL RESERVES	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
PHYSICAL ACCOUNTS (millions of cubic metres)															
[1] Opening Stocks	1011.5	950.9	871.3	830.0	794.5	760.2	719.9	696.0	649.4	657.6	640.7	648.5	634.7	613.8	592.9
[2] Additions															
[3] Discoveries	1.6	2.5	4.8	24.9	19.2	9.0	15.0	16.8	21.4	29.1	32.7	28.6	20.9	17.7	17.0
[4] Development and Reevaluation	2.1	5.9	5.1	−1.9	10.3	5.1	7.2	−16.5	24.8	−12.0	9.7	−14.1	1.8	2.5	−3.4
[5] Enhanced Oil Recovery	3.3	−27.0	9.2	1.4	4.8	8.6	10.4	6.6	17.9	24.1	21.6	24.6	10.5	16.5	7.8
[6] Depletion	67.5	61.0	60.4	60.0	68.5	63.2	56.5	53.6	55.0	59.2	56.2	53.2	53.9	57.2	53.8
[7] Net Change	−60.5	−79.6	−41.3	−35.6	−34.2	−40.5	−23.9	−46.7	9.1	−16.0	7.6	−14.1	−20.9	−20.5	−32.4
[8] Closing Stock	950.9	871.3	830.0	794.5	760.2	719.9	696.0	649.4	657.6	640.7	648.5	634.7	613.8	592.9	560.5
UNIT VALUES ($/cubic metre)															
[9] Average Wellhead Price	45.79	53.73	64.40	76.77	82.97	97.75	119.36	157.64	201.29	212.44	220.07	117.58	145.35	104.92	127.74
[10] Production and Capital Costs	13.32	16.16	16.41	19.28	20.95	30.24	43.17	54.60	55.37	62.67	73.24	77.42	85.21	88.95	100.00
[11] Net Price	32.47	37.57	47.99	57.49	62.02	67.51	76.19	103.04	145.92	149.77	146.83	40.16	60.14	15.97	27.74
MONETARY ACCOUNTS (millions of $)															
[12] Opening Stocks	27078	30676	32735	39832	45676	47147	48600	53025	66916	95985	95955	95216	25489	36911	9471
[13] Additions															
[14] Discoveries	52	94	230	1431	1191	608	1143	1731	3123	4358	4801	1149	1257	283	472
[15] Development and Reevaluation	68	222	245	−108	639	344	549	−1700	3619	−1797	1424	−566	96	40	−94
[16] Enhanced Oil Recovery	107	−1014	442	80	298	581	792	680	2612	3609	3171	988	631	264	218
[17] Depletion	2192	2292	2899	3449	4248	4267	4304	5523	8026	8866	8252	2136	3241	914	1492
[18] Net Change	−1965	−2990	−1962	−2047	−2120	−2734	−1820	−4812	1328	−2896	1144	−565	−1257	−327	−896
[19] Revaluation	5768	4852	9079	7883	3600	4174	6246	18693	27843	2531	−1882	−69175	12679	−27106	6976
[20] Closing Stock	30676	32735	39832	45676	47147	48600	53025	66916	95985	95955	95216	25489	36911	9471	15548

NATURAL GAS RESERVES	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
PHYSICAL ACCOUNTS (billions of cubic metres)															
[21] Opening Stocks	1486.5	1450.8	1501.7	1568.3	1665.2	1718.4	1747.0	1795.3	1853.1	1826.2	1798.4	1768.3	1720.1	1651.7	1627.7
[22] Additions															
[23] Discoveries	0.8	6.9	6.6	24.4	16.4	30.0	28.9	10.6	16.3	9.6	11.5	9.2	8.9	13.9	19.0
[24] Development and Reevaluation	20.0	98.7	120.9	138.9	106.8	82.5	88.1	108.1	22.7	30.9	31.1	12.6	−8.9	50.7	68.8
[25] Depletion	56.6	54.6	61.0	66.4	70.0	83.8	68.6	60.9	66.0	68.3	72.8	69.9	68.4	88.6	65.8
[26] Net Change	−35.8	51.0	66.5	96.9	53.2	28.7	48.4	57.8	−27.0	−27.8	−30.2	−48.1	−68.4	−24.0	22.0
[27] Closing Stock	1450.8	1501.7	1568.3	1665.2	1718.4	1747.0	1795.3	1853.1	1826.2	1798.4	1768.3	1720.1	1651.7	1627.7	1649.7
UNIT VALUES ($/000 cubic metres)															
[28] Average Composite Wellhead Price	38.83	54.76	64.25	66.70	80.82	117.66	117.40	146.60	135.26	144.50	138.79	107.13	92.35	73.97	76.57
[29] Production and Capital Costs	18.54	24.09	27.07	31.97	39.47	60.77	65.37	76.75	76.05	75.24	72.29	76.51	81.95	68.91	75.69
[30] Net Price	20.29	30.67	37.18	34.73	41.35	56.89	52.03	69.85	59.21	69.26	66.50	30.62	10.40	5.06	0.88
MONETARY ACCOUNTS (millions of $)															
[31] Opening Stocks	12600	29444	46055	58313	57839	71056	99381	93411	129448	108128	124553	117587	52675	17177	8240
[32] Additions															
[33] Discoveries	18	212	245	848	678	1707	1504	740	965	665	765	282	93	70	13
[34] Development and Reevaluation	408	3027	4495	4825	4418	3556	4564	7551	1344	2140	2068	386	−93	257	60
[35] Depletion	1148	1675	2268	2306	2895	3630	3569	4254	3908	4730	4841	2140	711	448	58
[36] Net Change	−726	1564	2472	3367	2200	1633	2518	4037	−1599	−1925	−2008	−1473	−711	−121	15
[37] Revaluation	17569	15051	9781	−3840	11017	26696	−8490	31992	−19717	18353	−4964	−63447	−34780	−8820	−7129
[38] Closing Stock	29444	46055	58313	57839	71056	99381	93411	129448	108128	124553	117587	52675	17177	8240	1126

Source: National Accounts and Environment Division, Statistics Canada

Table 22: Asset Balances of Net Tangible Assets (Subsoil assets) in Monetary Units

	Economically Non-produced Natural Assets: Subsoil Assets
[1] Opening stocks (market values)	-proven (developed and undeveloped) reserves -valued at discounted value of future net returns
[2] Net capital formation (market values)	
[2.1] Gross capital formation	-exploration expenditures
[2.2] Consumption of fixed capital	
[3] Volume change of natural assets due to economic use (market values)	
[3.1] Ecological valuation	
Quantitative depletion	-reflect future scarcity of assets -valued at net operating surplus, "user cost", net price -estimated at "ecological value": costs for maintaining level of natural capital or total capital (man-made and natural)
[3.2] Adjustment due to market valuation	
Quanitative depletion	-adjustment to market values (net price of depleted assets: current market price minus exploitation costs)
[3.3] Volume changes due to discoveries, development and revisions, etc.	-valued at discounted flow of future market prices and exploitation costs
[4] Revaluation due to market price changes	
[5] Closing stocks (market values)	
'([1]+[2]+[3]+[4])	-proven (developed and undeveloped) reserves -valued at discounted value of future net returns

Source: SNA Handbook on Integrated Environment and Economic Accounting, UN (1990)

While we have presented monetary values of the opening/closing stocks in Tables 17 to 19, the issue of how to value depletion appropriately in the reconciliation accounts has not been resolved. As explained above, depletion (that is resource depletion) could be valued at a current net price or the discounted value per unit when using a present value approach.[40]

13.1 Sectoring

Complete accounts for all institutional sectors have not (yet) been developed in the United Nation's System of Environmental and Economic Accounting (SEEA) (Bartelmus, 1991). The main emphasis has been on the development of accounts that measure the tangible wealth of natural resources. Transactions related to income distribution and those concerning intangible assets, including exploitation rights are excluded from the SEEA. A more comprehensive analysis of the interrelationship between the economy and the environment would require a further expansion of all institutional accounts.

This case study for crude oil and natural gas reserves in Alberta makes no attempt to apportion the value of the reserves to various institutional sectors of the Balance Sheet. There has been no serious attempts in dealing with this issue in the literature but the following discussion presents some of the concepts introduced by the SNA Revisions (United Nations, 1990) and by other studies.

Table 23 presents integrated balance sheet and accumulation accounts for all sectors.[41] Table 24 present the current Canadian Balance Sheet Matrix for comparison. The Revised SNA suggests that the development of *key sectors* and *key activities* (United Nations, 1990). For example, when key activities are based on natural non-renewable resources like subsoil assets, the sector accounts (e.g. oil and mining industries and governments (as owners of the resources)) have to record the changes in these resources. The difficulty lies in the distribution of "income" between the

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39. It is assumed that exploration costs (geological and geophysical expenditures in the case of the CSNA) represent intangible assets and therefore are included as part of the value of the non-produced subsoil asset. Other exploration and development expenditures are treated as produced tangible assets and exploitation rights (land acquisition and rental costs in the CSNA) are excluded from the Bartelmus et al model.
40. Of course, this does not present a problem when the net price approach is used.
41. While this section focussed on the issue of sectoring, the table shows detailed classification of assets. Of importance to the sectoring of the value of subsoil assets is the treatment of mineral exploration costs and rights to exploit subsoil assets. It is proposed that the former be treated as an intangible non-produced asset and the later be treated as an intangible non-produced asset. These treatments differ from those used in the CSNA.

Table 23. Integrated Balance Sheet and Accumulation Accounts (for the Nation and for Sectors)

ASSETS, LIABILITITES AND NET WORTH	Opening Balance Sheet	Capital and Financial Accounts[3]	Other Changes in Volume of Assets Account	Revaluation Account	Closing Balance Sheet	Environmental Account
ASSETS						
Non-financial assets						
Produced assets						
Inventories[4]						
Fixed assets						
Tangible fixed produced assets						
Machinery and equipment						
Construction						
Intangible fixed produced assets						
Mineral exploration related to subsoil resources[1]						
Non-produced assets						
Tangible non-produced assets						
Land						
Subsoil assets						
Coal, oil and natural gas reserves						
Metallic mineral reserves						
Non-metallic mineral reserves						
Historical monuments, antiques, art objects						
Intangible non-produced assets[2]						
Financial Assets						
LIABILITIES						
NET WORTH						

[1] capitalized mineral exploration costs
[2] includes rights to exploit subsoil assets or mineral deposits
[3] includes gross fixed capital formation and capital consumption
[4] Levin (1991 a,b) suggests treating subsoil assets as inventories

Source: National Accounts and Environment Division, Statistics Canada; United Nations Revised System of National Accounts, Volumes I–IV (1990)
Levin (1991 a,b)

Table 24. Canadian National Balance Sheet Account Matrix

Category	Sectors: I and II Persons and Unincorporated Business	III Non-financial Private Corporations	IV Non-financial Government Enterprises	V Monetary Authorities	VI-VIII Banks and Financial Institutions	IX Public Financial Institutions	X-XI Federal and Other Levels of Government	XII Social Security Funds	XIII Rest of the World
Total Assets									
Non-financial Assets									
Residential Structures									
Non-residential Structures									
Machinery and Equipment									
Consumer Durables									
Inventories									
Land									
Financial Assets									
Liabilities and Net Worth									
Liabilities									
Net Worth									

Source: National Accounts and Environment Division, Statistics Canada

government sector and the petroleum and mining subsectors. As government bodies often own and control the use of a substantial part of mineral assets of their country, the government sector requires the classification of non-reproducible tangible assets into its accounts (United Nations, 1977). However, subsoil assets are crucial to the activities of the petroleum; and mining industries.

Levin (1991) suggests treating natural resources as "imports" from an "environmental" account added to the capital account, registering additions to reserves at a stage involved in economic activities. One can view mineral wealth as having a balance sheet in the previous period or at the opening of the accounts with no addition to the production or income accounts symmetrical to subsequent subtraction. Levin (1991) recognizes the environment as a separate sector or account similar to the rest-of-the-world account. The national economy may be viewed as importing natural resources from the environment through discovery or development. These "imports" would enter the capital account as an addition to inventories or as fixed capital paid for by a corresponding transfer from the environment. Like other capital assets, natural resources may be considered as additions to capital at the time they enter the economic system and as subtractions from capital in the later periods when they are used.

Table 25 presents the Balance Sheet for both economic and environmental assets, modified after the Mexican study completed by van Tongeren et al (1991). The concept of capital formation is changed to a new concept of capital accumulation which takes into account not only changes in produced assets as a result of depreciation, but also changes in the stock of non-produced assets resulting from new discoveries of non-produced assets.

In the Balance Sheet account developed for Mexico, two additional columns are added to it. The first additional column refers to non-produced assets that are directly "used" in economic activities together with produced assets. The second additional column refers to assets that are only "affected" by economic activities, that is non-produced environmental assets. Table 25 illustrates these new concepts with the 1989 values of crude oil reserves in Alberta and produced fixed capital stock.

Table 25. Balance Sheet and Reconciliation Accounts for Produced and Non-produced Economic and Environmental Assets including Crude Oil Reserves in Alberta based on the Net Price Method (in millions of dollars)

	A. Economic Assets									B. Environmental Assets
	1. Fixed Assets					2. Stocks				
		Net Capital Accumulation					Changes in Stocks			
Sectors	Opening Balance Fixed Assets	Gross Fixed Capital Formation	Consumption of Fixed Capital	Reconciliation	Closing Balance Fixed Assets	Opening Balance Stocks	Produced Assets	Non-produced Assets	Closing Balance Stocks	Non-produced Environment Asset
Total										
Produced Assets										
Non-produced Assets										
Agriculture										
Forestry										
Fishing										
Petroleum										
Produced Assets:	17546.9	1766.4	(1616.8)	214.8	17911.3					
Non-produced Assets:										
Total reserve additions								593.6		(593.6)
Depletion								(1492.4)		
Revaluation of reserves								6976.1		
Sub-total						9470.9			15548.1	
Mining										
Other Industries										
Manufacturing										
Construction										
Services, etc...										

Source: National Accounts and Environment Division, Statistics Canada; modified from van Tongeren et al (1991) and Levin (1991).

Economic assets are used as production factors in the generation of output while environmental assets are not considered as production factors and their contribution to the generation of output reflects the non-availability of information on asset balances (van Tongeren et al, 1991). Therefore, new discoveries of oil represent an addition to non-produced economic assets and reduction in the quantity of environmental assets.[42]

In summary, no attempts have been made in the literature to apportion the value of natural resources among the institutional sectors in the Balance Sheet. In the United Nation's SNA Revisions, it is suggested that key activities and key sectors be used in treating the value of natural resource. In earlier UN publication, it is recognized that governments are the owners of subsoil assets and that subsoil assets are an important part of the mining industry's assets, but no attempt is made to separate the value. Levin (1991) and van Tongeren et al (1991) suggest creating an environmental sector or environmental assets in which reserve additions are "imported" into the capital accounts and economic asset categories, respectively.

14.0 ANALYSIS AND SUMMARY

Most monetary values for oil and natural gas reserves in the current literature are based on the net price approach which is based on the Hotelling model. In Alberta, with the collapse of world oil and natural gas prices since 1986 along with increasing extraction costs, the value of resource rents have decreased significantly. Analysis of the data in this study find that the assumptions of the Hotelling model are too restrictive. It appears that the current net price is not appropriate for valuing future production. The net price approach seems to have overvalued future production in the early 1980s in light of the price collapse in 1986 and increasing extraction costs. However, the net price provides a basis for comparison with other studies and accounting procedures are similar to the net present value approach. Results from this study indicate that in 1989, the value of oil reserves ranged from \$15.5 billion to \$34.7 billion and the value for natural gas reserves, \$1.1 billion to \$55.2 billion using various net price approaches.

42. This classification of non-produced assets relates to the value of EDP (environmental NDP) which is GDP less the value of oil depletion and not net accumulation of reserves, as done in other studies.

The net present value approach or discounted value of future net returns has been proposed by the UN SNA *Handbook on Integrated Environment and Economic Accounting* and Bartelmus et al (1991) as the most appropriate method of monetary valuation of the opening and closing stocks and changes to the stock due volume and price changes. Soloday (1980), Ward (1982) and Landefeld and Hines (1985) as well as Japan and Hungary have also used the present value approach. Discounted cash flow analysis is the standard approach used by companies to value properties and is used in Annual and SEC 10K Reports. While we have calculated several values using this approach, we present only some these results. Values presented in this study show that in 1989, the value of oil reserves varied from $11.4 billion to $12.3 billion and the value of natural gas reserves ranged from $0.6 billion to $14.4 billion. Present value estimates vary considerably depending on the assumptions made. Several assumptions relating to this method such as the appropriate discount rate and the calculation of a normal return to capital, etc. need to be chosen in order to produce reliable results.

The replacement cost approach has been presented in the literature as a method of measuring resource scarcity and as an alternative to approximating the value of rent. The replacement cost (or perpetual inventory approach) is used to value some non-financial assets in the CNBSA. Several models of deriving replacement costs for crude oil and natural gas have been published in the literature. The methodology outlined by Eglingtion and Uffelmann (1983) and McLachlan (1990) are presented here. Results for the value of crude oil was $48.5 billion and $88.3 billion for natural gas in 1989. Unit replacement costs for crude oil have decreased since 1987 while these costs have increased for natural gas.

The focus of this study is to determine an appropriate method of natural resource valuation. While the development of the physical accounts is based on the definition of established reserves, the monetary accounts require further evaluation in order to incorporate monetary values into the CNBSA. The present value approach appears to conform most closely to the development of wealth accounts. This approach allows us to separate the value of man-made capital employed by the industry from the value of the natural resource itself and identify capital gains and losses due to price changes.

This paper makes no attempt to apportion the value of oil and gas reserves by sector. This will be addressed in a later paper. The issue of land rent and its place in the valuation of oil and gas assets will need to be further explained, also.

APPENDIX 1. The Hotelling Model

The Hotelling hypothesis (Hotelling, 1931) states that under certainty, in the absence of extraction costs and under competitive market conditions, the price of a natural resource rises at the market rate of interest (e.g. the riskless rate) to preclude arbitrage (Sundaresan, 1984). This is the basic underlying concept of Hotelling's "r per cent rule". Whether or not this hypothesis holds true in "real world" situations or under conditions of inhomogeneous natural stock, incomplete exhaustion, increasing exploration and extraction costs, etc. is the subject of considerable debate in the literature. The ability of the theory of exhaustible resources to describe and predict the actual behaviour of resource markets is questionable (Halvorsen and Smith, 1991). As Adelman (1991) states, removing the assumption about fixed resource stocks and assuming an inventory, does not make the Hotelling theory wrong. The true measure of resource scarcity is the present value of the mineral reserve to be extracted. Prices need not rise over time - decreases are usual and increases are rare.

A competitive firm with a nonrenewable resource requires that:

$$p = MC + \text{opportunity cost of depletion}$$

where p is the price of the resource and MC is the marginal cost. The opportunity cost is the value of the unextracted resource or the *resource rent*. This resource rent represents the rate of return to the mine. When there is a positive discount rate, the rent is positive and rises in nominal value as depletion occurs. To have mineral extraction, the value of the resource rent must increase at the same rate as that of alternative assets (Hartwick and Olewiler, 1986). For efficient extraction of a mineral, the present value of a unit of a homogeneous stock of the mineral must be identical regardless of when it is extracted. If the value of the rent increased at a rate greater than the interest rate, mine owners would hold on to the reserves rather than sell them as the value will be higher at a later date. If rents rose more slowly than r, mine owners would tend to produce the natural resource[1], as they would maximize their return by liquidating the resource as soon as possible.[2]

1. While the Hotelling model is based on efficient resource depletion, as El Serafy (1989) points out accounting methods do not indicate an *ex ante* optimal rate of depletion, but use an *ex post* value based on the resource owners' decision about liquidating the natural resource. This rate of extraction is based on a number of factors including expectations about future prices.

The net benefit of the marginal unit extracted is the resource rent and the present value of the rent on the margin in each period must be equal in a Hotelling model:

$$p_t - c = (p_{t+1} - c)\left(\frac{1}{1+r}\right)$$

where p_t is current average unit price, c is current unit cost extraction and r is the (market) rate of interest. In such a case, there should be a declining rate of extraction of the resource over time periods as the producer would maximize his income.

A variation of the Hotelling r-per cent rule that allows extraction costs to increase (change) can be written as:

$$(p_t - c_t) = (p_0 - c_0)\,(1+r)^t$$

$$t = 0.....\mathrm{N}$$

where the *real* price of the resource net of marginal extraction costs grows over time at a rate equal to the real rate of interest (Miller and Upton, 1985a). Extending the "Hotelling Principle", as done by Miller and Upton (1985a) and Landefeld and Hines (1985), the value of remaining reserves in situ derived from:

$$V_0 = (p_0 - c_0)\sum_{t=0}^{T} q = (p_0 - c_0)\,R_0$$

where V_o is the value of the reserves, R_o is the quantity of remaining reserves and q_t is the quantity extracted in each period. This valuation method assumes that marginal costs are equal to average costs, so that the present value of the net price on any unit must be the same, regardless of when it is extracted (Miller and Upton, 1985a).

The equation for the shadow price or rent of a natural resource, *HR*, shows that rent need not rise at the ratio of interest as a resource is depleted. The rate of change of rent, $\dot{HR}/HR$ is defined as :

2. The Hotelling rule equates the equilibrium rate of increase in the value with the rate of interest. However, this approach ignores the role of capital in exploration, development and extraction. While a higher discount rate encourages resource use, it also increases the cost of capital services, thus increasing marginal cost (Stollery, 1990).

$$\frac{\dot{HR}}{HR} = r + \left(1 - \frac{p}{HR}\right) q_R$$

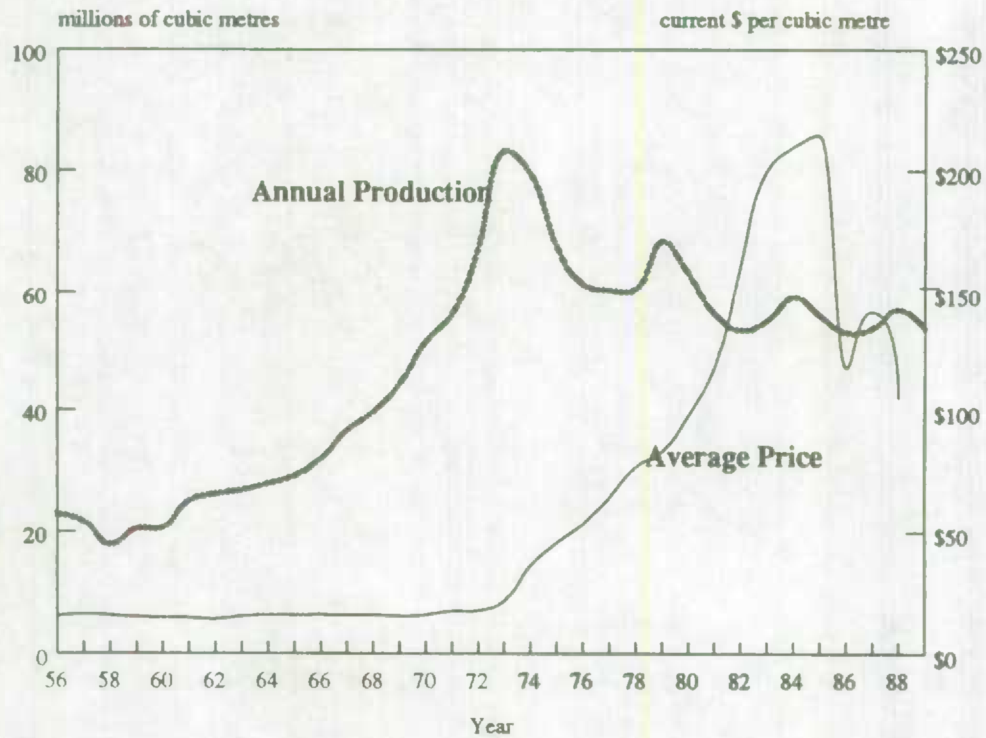
where p is the price of the resource and q_R is the extractive output of the resource stock R. The rate of change of rent is equal to the rate of interest r when $q_R=0$ or $p=HR$ (i.e. there is no marginal extraction cost). These conditions do not generally occur and assuming $q_R>0$ and $p>HR$ then $\dot{HR}/HR<r$ (Fisher, 1979). Thus, the return to holding a unit of the resource in the stock over a short interval, $\dot{HR}/HR$ is less than the return on an alternative investment, r. As Fisher points out not only is $\dot{HR}/HR<r$ but it may become negative. These results are counter to Hotelling's model that rent or the shadow price of an exhaustible resource increases over time at precisely the same rate of interest as the resource is depleted.

Actual price paths of oil and natural gas are quite different from the Hotelling price path. Figures 4 and 5 present the price and annual production of oil and natural gas in Alberta for 1957-1989. While prices have increased up to 1985, the period from 1986 to 1989 has been a time of decreasing resource prices. The assumption of certainty in the Hotelling model appears to restrict its predicative power. But models that include uncertainty make measurement or quantification almost impossible so that the price paths are difficult to predict. Hartwick and Olewiler (1986) suggest that with finite stocks and positive demand at any price, prices will eventually rise in a Hotelling-like fashion, but there may be periods of declining prices before a final rise due to the finiteness of the stock (Figure 6, after Hartwick and Olewiler, 1986).

Adelman (1990) also identifies the "failure of the rising-price" paradigm in a Hotelling world. Rents are directly determined by the crude oil price. Price for oil on world markets has decreased in real terms. Worldwide stability of development costs shows that oil has not become scarcer since 1955 (Adelman, 1990).[3],[4] The belief that oil prices must rise in the long run is based on diminishing returns (i.e. increasing development and exploration costs), not on the exhaustibility of resources (economic exhaustion before physical exhaustion). As marginal cost rises over time,

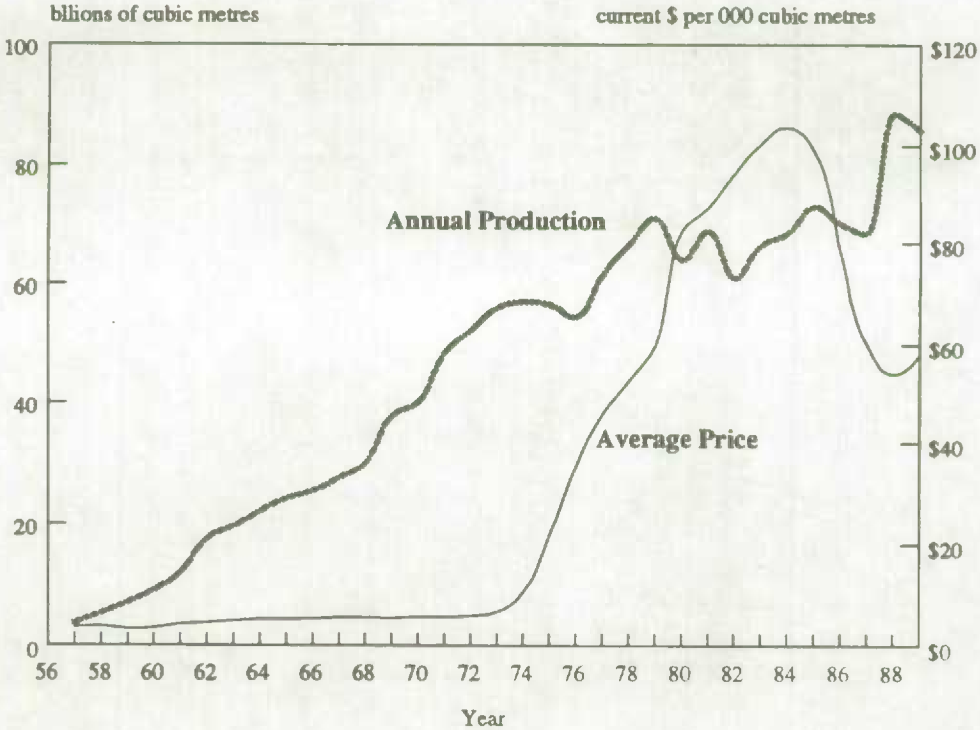
3. Development investment per unit of reserves added can be used as an indicator of crude oil resource scarcity.
4. World reserves of crude oil have increased from 86 billion cubic metres in 1969 to 161 billion cubic metres in 1989. Most of the increase was in the Middle East (BP Statistical Review of World Energy, 1990).

Figure 4. Production and and Average Wellhead Price for Crude Oil in Alberta



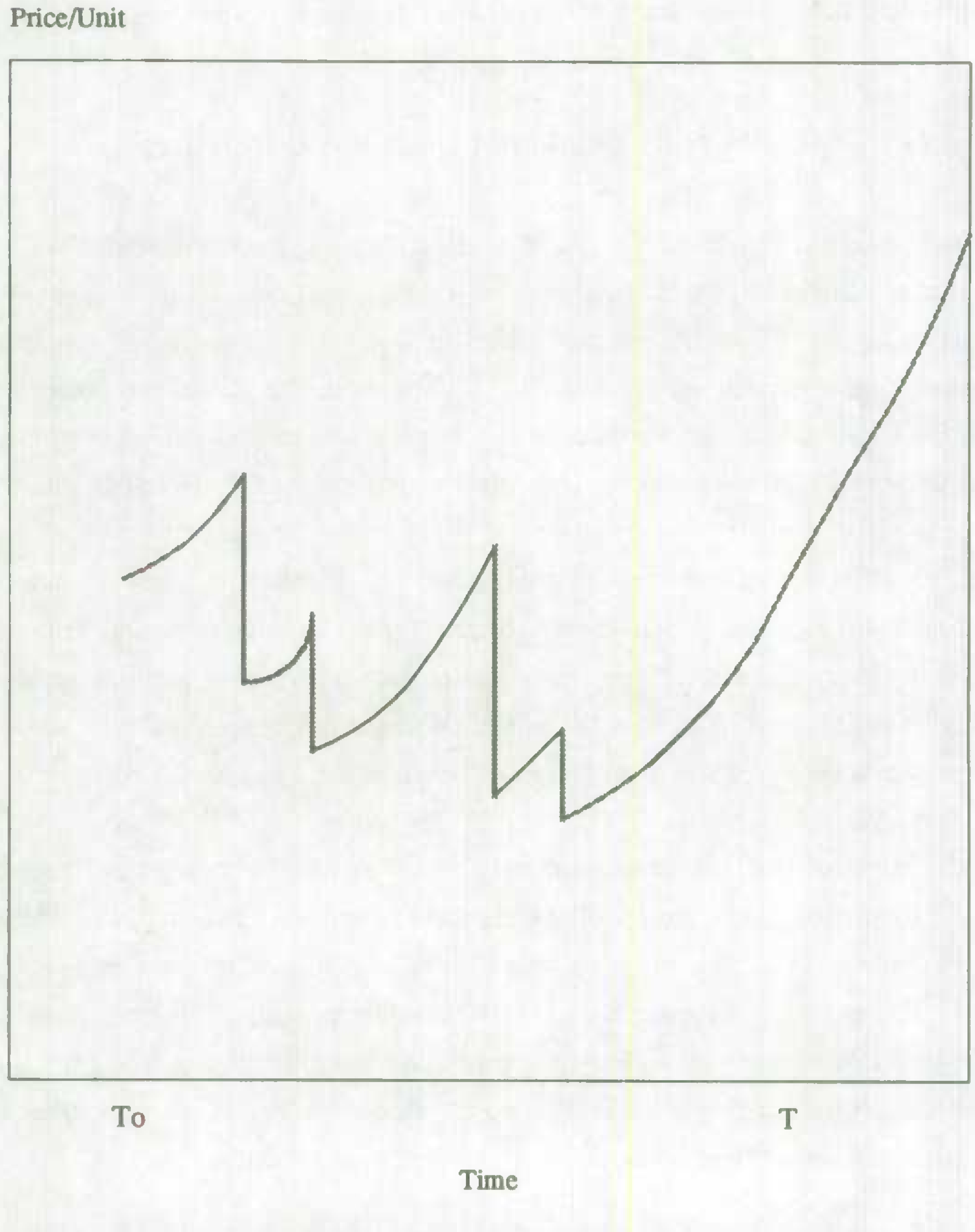
Source: CPA, ERCB and Statistics Canada

Figure 5. Production and and Average Fieldgate Price for Natural Gas in Alberta



Source: CPA, ERCB and Statistics Canada

Figure 6. Trends in observed prices



The trend in observed prices can decline over long periods if new discoveries ofore are made which were not anticipated. Finiteness of the stock implies that prices must ultimately rise.
Source: Hartwick and Olewiler (1987)

so does the market price. Yet, as Adelman notes, real prices for most minerals have declined. This suggests that diminishing returns are opposed by increasing knowledge of where additional reserves are located and improved methods of extraction (Adelman, 1987).

Below is a discussion of how diminishing returns and technological changes can still yield increasing Hotelling rents under conditions of changing resource prices.

The Effect of Technology and Quality of the Natural Resource

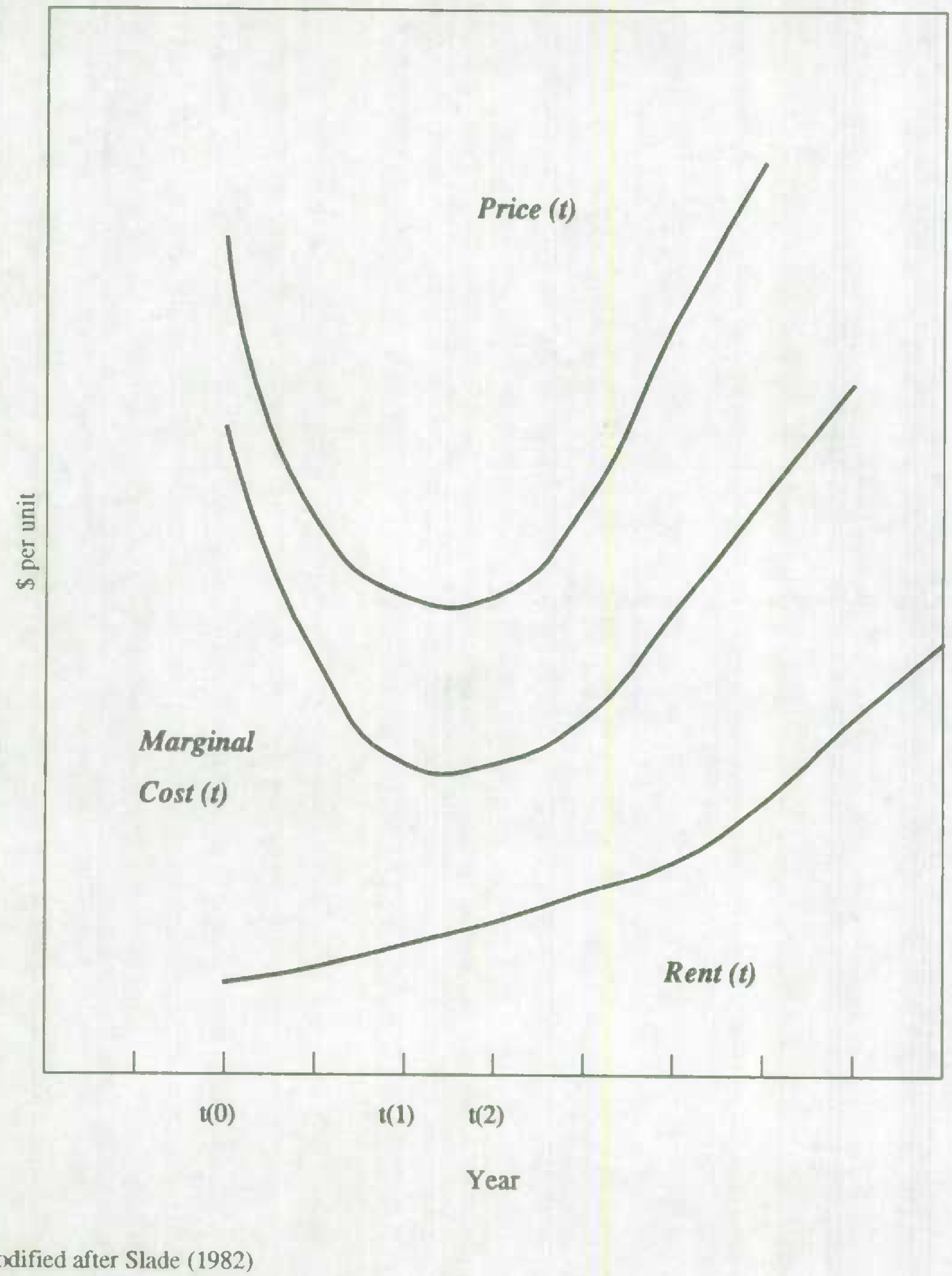
Slade (1982) modifies the Hotelling model to incorporate assumptions about ore grade and technological advances. Figure 7 illustrates that marginal cost depends on the rate of technical change and ore grade. Prices (P_t) and marginal costs (MC) initially decrease because the rate of technological change offsets ore grade decline. Then technological change cannot offset cost increases due to decreasing ore grades, and as a result prices increase. However, rents R_t (the difference between P_t and MC) over time are increasing as stated in the Hotelling rule.

However, it is difficult to determine where the oil and gas industry in Alberta is in terms of the price, marginal cost and mineral rent curves. Technological improvements appear to have offset increases in discovery (exploration) costs whereas operating costs have been increasing as lower quality (higher cost) reservoirs are being exploited. With increasing marginal costs and fluctuating (decreasing) world oil prices, the industry seems to be between t(1) and t(2) in Figure 7.

While discovery costs per unit have decreased since 1981, unit operating costs have increased significantly for oil and natural gas in Alberta. Figure 8 shows the trends in prices, marginal costs and rent for crude oil in Alberta. The resource rents appear to have increased in a Hotelling-type trend until 1985, but with increasing marginal costs and decreasing prices, rents have decreased. Decreasing rents may represent a short-run phenomena and the fact that world prices have not responded to resource scarcity or increasing costs. Because Canada is a price taker with high marginal costs, it does not have control over the amount of mineral rent obtained.

Slade's version of the Hotelling model appears to be independent of mineral rents increasing at the rate of interest. Hotelling rents increase because of changes in resource prices, resource quality and technology.

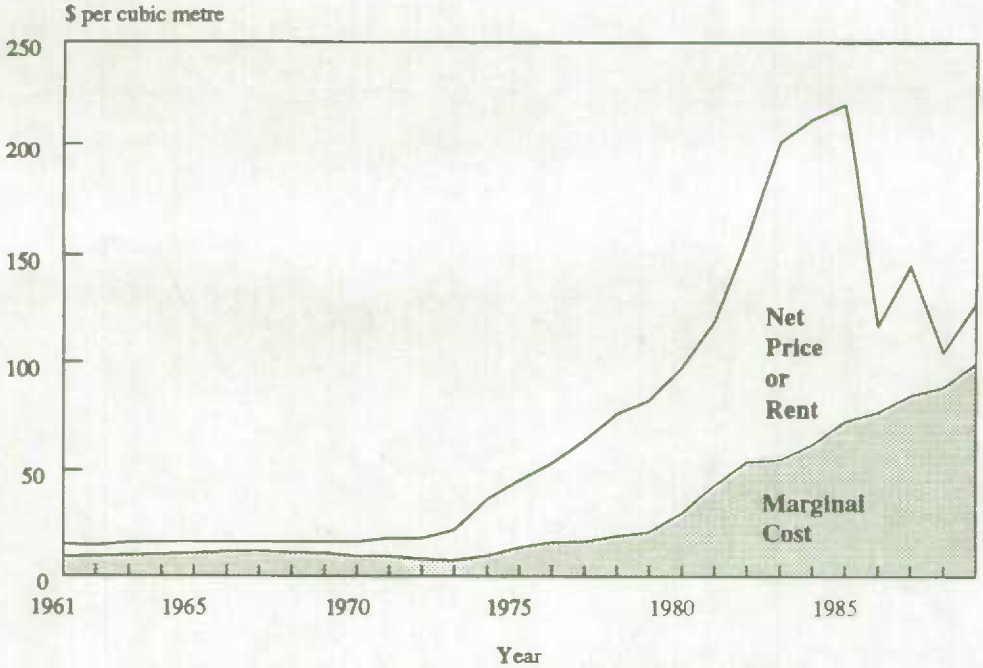
Figure 7. Marginal Cost, Price and Mineral Rent over Time



Source: modified after Slade (1982)

Figure 8. Marginal Cost and Rent for Crude Oil in Alberta

(in $ per cubic metre)



Source: National Accounts and Environment Division, Statistics Canada

As Adelman (1986b) states "the discounted net return from extracting a mineral unit from a given deposit in any year must equal that in any other year, which in turn equals any return from a holding with equal risk" (p. 324). This suggests that net prices do not necessarily have to rise but rather change at the rate of return on alternative investments.[5]

The Hotelling rule assumes that current net prices reflect long-run equilibrium. As suggested by Gervais (1990), this implies oil and gas prices should be steadily increasing through time. However, historically prices have fluctuated greatly. While the Hotelling r% rule provides a simple tool for calculating the value of reserves, its assumptions may be too simplified and the present value approach using historical price and cost data to determine the Hotelling rent in each year may be more appropriate.

5. There are many interpretations in the literature of what the rate of increase of the price or net price is. For example Sundaresan (1984) states that the price of a natural resource (in a Hotelling world) must rise at the market rate of interest (i.e. the risk-free rate) to preclude arbitrage.

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