C

NORTH CANADIAN OILS LIMITED

Year Ended December 31, 1992

ANNUAL INFORMATION FORM

February 22, 1993

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ABBREVIATIONS

The following standard oil and gas abbreviations have been used throughout this document:

bbl – barrel
bpd – barrels per day
mbbls – thousand barrels
mmbbls – million barrels
mcf – thousand cubic feet
mcfe – thousand cubic feet equivalent *
mmcf – million cubic feet
mmcfd – million cubic feet per day
bcf – billion cubic feet
bcfe – billion cubic feet equivalent *
tcf – trillion cubic feet
NGLs – natural gas liquids

* Converted at 1 bbl = 10 mcf

EXCHANGE RATES

In this document, dollar amounts are expressed in Canadian dollars unless otherwise indicated. The following table sets forth the range of spot prices for the Canadian dollar in United States dollars (rounded to the nearest cent) as reported by the Royal Bank of Canada for the periods indicated.

	First Quarter		Second Quarter		Third Quarter		Fourth Quarter	
	High	Low	High	Low	High	Low	High	Low
1988	0.81	0.77	0.83	0.82	0.84	0.81	0.84	0.81
1989	0.85	0.83	0.85	0.83	0.86	0.84	0.87	0.85
1990	0.85	0.84	0.86	0.85	0.87	0.87	0.86	0.86
1991	0.87	0.86	0.88	0.86	0.88	0.86	0.89	0.86
1992	0.88	0.83	0.85	0.83	0.85	0.80	0.81	0.78

On January 29, 1993, the noon buying rate in New York, New York for the Canadian dollar, as reported by the Royal Bank of Canada, was U.S.$0.79.

Item 1: NAME AND INCORPORATION OF THE COMPANY

North Canadian Oils Limited is a Canadian company incorporated under the laws of Alberta on July 25, 1947, by Certificate of Incorporation and continued under the laws of Canada on June 20, 1983. Effective July 1, 1986, North Canadian Oils Limited and Merland Explorations Limited ("Merland") amalgamated pursuant to the provisions of the Canada Business Corporations Act and pursuant to an Amalgamation Agreement dated May 1, 1986, to continue as one corporation under the name of North Canadian Oils Limited ("NCO"). Prior to this, Merland was a 53 percent subsidiary of Bankeno Mines Limited, which in turn was an 86 percent subsidiary of NCO. Subsequently, Bankeno Mines Limited was amalgamated with its 100 percent subsidiary Bankeno Resources Limited to continue as one corporation called Bankeno Resources Limited ("Bankeno"). Effective January 1, 1991, NCO amalgamated with its wholly-owned subsidiary Bankeno. The Company's principal and head office is located at Suite 700, 112 - 4th Avenue S.W. Calgary, Alberta, T2P 4B2. In this document, North Canadian Oils Limited and its subsidiaries are collectively referred to as the Company or NCO as the context may indicate.

Item 2: RECENT DEVELOPMENTS

Under an agreement dated December 18, 1992, Norcen Energy Resources Limited ("Norcen") agreed to acquire the combined 50.5 percent common share interest in NCO owned by Noranda Inc. ("Noranda") and Daal Energy Holdings Inc. in consideration for 0.67 subordinate voting ordinary shares of Norcen for each NCO common share. The agreement is subject to certain conditions precedent including the approval of Norcen shareholders. Norcen currently intends to seek the required shareholder approval at a meeting to be held in early April. Norcen has indicated its intention to propose to NCO a subsequent combination of Norcen and NCO pursuant to which the holders of other common shares of NCO would also receive shares of Norcen on the same basis as Noranda and holders of preferred shares of NCO would receive, at the determination of Norcen, cash or preferred shares of Norcen having the same attributes as the NCO preferred shares. Norcen has also announced, in connection with these matters, that it is authorized to submit a proposal to its shareholders to amend its share capital changing its multiple voting and subordinate voting ordinary shares into common shares on a one-for-one basis.

The Board of Directors of NCO has appointed a special committee consisting of Mr. Paul J. Hill, Mr. Marshall A. Jacobs and Mr. H. Earl Joudrie, to consider the Norcen proposal to combine Norcen and NCO following the acquisition of the 50.5 percent combined share interest by Norcen. The special committee has retained independent legal counsel and has engaged an independent financial advisor to assist it in its deliberations.

Item 3: BUSINESS AND PROPERTY

NCO is an oil and gas exploration, production, marketing and power cogeneration company. Exploration and production activities are concentrated in the Western Canadian Sedimentary Basin while marketing and cogeneration activities have a North American focus. The Company also owns a 25 percent royalty interest in a major lead and zinc mine located in the Canadian Arctic and a portfolio of investments with a book value of $159.9 million.

In recent years, NCO has emphasized asset growth and diversification within the oil and gas industry by focusing on the exploration, production, acquisition and direct marketing of natural gas. NCO has integrated and diversified its natural gas business by participating in power cogeneration projects. Projects are being pursued throughout North America but to date have only been developed in the United States. NCO also owns two pipelines which are located in Alberta, one transports natural gas to industrial customers and the other ceased operations in 1992.

General Development of Business from 1988 to 1992

Since 1987, NCO's assets have grown through its business development and diversification activities. The following is a summary of the major events during this period.

Oil and Gas Assets

During the past five years, NCO has increased its crude oil and natural gas base primarily through acquisitions. Cash generated from operations, after the payment of dividends on common and preferred shares, has been reinvested annually in the Company's capital expenditures program.

Effective April 1, 1988, Bankeno acquired the oil and gas assets, and natural gas marketing business of Brenda Mines Limited ("Brenda") for $31.5 million. Following the acquisition, Bankeno established a separate management and operations group and terminated a previously existing management agreement with NCO for those services. Effective June 30, 1990, pursuant to an offer to the minority interest shareholders of Bankeno, NCO acquired all the remaining outstanding common shares of Bankeno for a cash consideration of $39.9 million. Bankeno was amalgamated with NCO effective January 1, 1991.

Pursuant to a January 30, 1990 agreement, NCO acquired 47 percent of the common share equity, a $20.0 million secured convertible debenture, and $12.7 million of unsecured convertible debentures of Coseka Resources Limited ("Coseka") from Bramalea Limited, a related company, in consideration for the issuance of 900,000 NCO common shares valued at $20 per share. Coseka was a publicly listed oil and gas company with primarily mature oil and gas properties located in western Canada.

Due to the financial difficulties of Coseka, NCO, with the approval of an independent committee of the Board of Directors of Coseka, began negotiations with Coseka's lenders to reorganize and restructure Coseka's affairs. These negotiations led to the joint filing of a Plan of Arrangement ("the Plan") by NCO and Coseka with the Alberta Court of Queen's Bench in October 1990. Under the Plan, which received the prerequisite shareholder, creditor and court approval effective January 10, 1991, NCO paid approximately $107.2 million for Coseka's lender debt and outstanding common shares. NCO then transferred Coseka's common shares to 158152 Canada Inc., a wholly-owned subsidiary of NCO, which was in turn amalgamated with Coseka. The restructured debt of Coseka was assumed by NCO Acquisition Limited, a wholly-owned subsidiary of NCO.

On November 20, 1991, the Company announced a downward revision to its constant price case proven reserves of 189 bcf of natural gas and 0.8 mmbbls of crude oil and NGLs. These negative revisions were required after it was determined by NCO engineers that the lower of three zones, in a major natural gas producing area located in Saskatchewan, was not contributing to production. Economic and performance related problems in several other properties also contributed to the negative revision.

In 1992, the Company separated its properties into core and non-core categories. The non-core properties are generally properties with small working interests, low cash flows, high operating costs and/or are located in areas where the Company does not plan future activities. These properties are managed separately from the core properties with the objective of either enhancing their value or disposing of them. During 1992, the Company disposed of $18.7 million in non-core properties and plans to dispose of additional properties over the next several years at market prices. Proceeds from the sale of non-core properties will be reinvested in the acquisition, exploration and development activities in core areas.

In September 1992, the Company completed the acquisition of Shell Canada Limited's ("Shell") interest in the Progress area of northern Alberta for $75 million. The Progress property is located near NCO's Knopcik facility, an area where the Company has been active for many years, and provides the Company with a strategic base of proven reserves in a core focus area where it has expertise. The acquisition provides NCO with upside potential from an exploration, exploitation and marketing perspective.

Marketing and Power Cogeneration

NCO's marketing activities commenced in Canada shortly after deregulation of the natural gas industry in 1986 to enable the Company to secure adequate markets and returns for its natural gas production. NCO's Canadian marketing operations grew through acquisition in 1988 when NCO merged its existing marketing group with that of Brenda upon its acquisition of Brenda's marketing business. These activities were expanded over time to include the use of strategic transportation space and third party natural gas production to satisfy direct sales contracts in excess of the Company's production capability.

Expansion of the Company's natural gas marketing activities into the United States commenced with the acquisition of certain strategic assets. In January 1988, NCO acquired 51 percent of the outstanding common shares of Trigen Resources Corporation ("Trigen"), a California corporation, for a total consideration of $1.3 million. Effective July 31, 1990, the Company purchased the minority shareholder's 49 percent interest for approximately $6.9 million. Subsequent to year end 1990, Trigen was renamed North Canadian Marketing Corporation and was merged with NCO's mid-west United States marketing operations to carry out marketing operations as one wholly-owned subsidiary of NCO in the United States. Prior to this merger, Trigen's investment in its wholly-owned subsidiary, Trigen Power Company, later renamed Ada Power Company, was transferred to North Canadian Power Incorporated, a wholly-owned subsidiary of NCO.

In 1990, NCO also became involved in the development, ownership and operation of power cogeneration projects which are expected to offer both an acceptable rate-of-return on investment and additional long term markets for natural gas. Power cogeneration is the sequential production of electrical and thermal energy from a single fuel source, generally natural gas. The Company owns equity investments in five cogeneration projects located in the United States. Three of these projects are operational and two are currently under construction.

Shareholder Capital

During the past five years, a number of financial events have impacted the Company's Balance Sheet.

- On August 3, 1989, the Company issued 4.5 million common shares under a prospectus for net proceeds of $96.5 million.
- In September 1989, the holders of the Class B Preferred Shares, Series 3, converted their shares into 3.2 million common shares prior to the expiration of the conversion rights attached to these shares.
- The conversion rights attached to the Class B Preferred Shares, Series 7 and 6, expired on June 30, 1990, and December 31, 1990, respectively.

Pursuant to the terms and conditions attached to the Class B Preferred Shares, Series 6, the Company is obligated to purchase for cancellation in the open market, in each calendar quarter commencing January 1, 1991, three-quarters of one percent of the Class B Preferred Shares, Series 6, outstanding at December 31, 1990. Pursuant to this obligation, the Company repurchased 42,300 (1991 – 39,300) Class B Preferred Shares, Series 6, during 1992 at a total cost of $1.0 million (1991 – $0.8 million).

The Company considers it prudent to repurchase its common shares in the open market when the shares are trading below certain levels. Accordingly, during 1991, the Company repurchased 229,200 common shares for a total consideration of $3.3 million under a Normal Course Issuer Bid which expired on December 14, 1991. NCO reinstated its Normal Course Issuer Bid on February 21, 1992, but did not repurchase any common shares under this Bid during 1992. The Normal Course Issuer Bid expired on February 19, 1993.

At December 31, 1992, the Company and its subsidiaries had a combined total of 443 employees.

Integrated Operations of NCO

Deregulation of the Canadian oil and gas industry, which commenced in 1986, focused on changing major aspects of the natural gas business including the move toward market sensitive pricing, easing of export restrictions, and a realignment of the pipeline infrastructure to allow buyers and sellers to transact directly. Prior to deregulation, gas prices were set by the Government of Canada and pipeline access was limited due to the monopoly position of traditional transporters.

In today's deregulated marketplace, companies can choose to either sell their natural gas production to the large system aggregators including Western Gas Marketing Limited ("WGML"), Pan-Alberta Gas Limited ("PAG"), and Alberta and Southern Gas Limited ("A & S"), sell directly to end-users, or sell to a marketer who resells to the end-user. When a company contracts its production to an aggregator, the producer receives the netback value of the aggregator's pooled sales. Contracts with aggregators generally have seasonal fluctuations in take levels. For a producer this means that although they have had to commit reserves and deliverability the aggregator has first call on the deliverability, leaving the producer little ability to effectively market gas which is not taken by the aggregator.

A company choosing the direct market approach can gain greater control over pricing within the constraints of the marketplace because it can decide what percentage of sales should go to short, medium, or long term markets, which geographical markets it should concentrate on, but most importantly, how to maximize the value of its particular reserve base and transportation portfolio. While the company must incur the administrative costs associated with direct marketing, it is also the primary beneficiary of those marketing efforts.

Although many Canadian producers direct market their own production, few have followed NCO's strategy to create its own cogeneration markets by building the in-house expertise to develop, finance and operate natural gas-fired cogeneration projects. Cogeneration projects generally have high year round load factors and attractive long term pricing. As these projects can be financed on a non-recourse basis, NCO has an opportunity to create additional natural gas sales markets for an equity investment that will itself earn a return.

NCO believes the synergy created by integrating its oil and gas, marketing and cogeneration operations enhances the value of the combined activities over that of the individual activities. The economics of exploration and acquisition activities are improved when efforts can be focused on securing reserves to satisfy attractive long term contracts. The Company's ability to negotiate long term gas contracts is also enhanced by a large, secure reserve base while the high take levels on cogeneration contracts, allows the Company to convert its reserves into cash flow much faster. This in turn can provide the Company with funds it can reinvest for the exploration and production of more reserves.

Oil and Gas Activities

Risks and Strategic Analysis

Approximately 43 percent of NCO's natural gas production is derived from shallow plays in southern Alberta and southern Saskatchewan where the Company has considerable expertise. However, these shallow gas plays are mature and are not compatible with the Company's marketing and cogeneration activities which benefit from higher deliverability and longer life reserves to support long term sales contracts. Consequently, the Company has made an effort over the past few years to focus its exploration activities in areas where multi-zone, larger reserve potentials exist. This exploration activity is generally of higher risk than the shallow gas plays, but NCO believes this risk is manageable as it will focus on areas where it has expertise, can maximize the results of drilling activities and keep costs as low as possible. The Company believes that exploration efforts must be driven by the economics of individual plays.

The current market of depressed product prices and asset rationalizations has provided an opportunity to acquire producing properties at reasonable prices. At year end 1991, NCO formed an acquisition group to actively seek out and purchase properties that would add reserves at acceptable costs. During 1992, NCO acquired Shell's interests in the Progress area of northern Alberta for $75 million which provides a strategic fit with NCO's existing asset base.

NCO also formed an asset rationalization group with the mandate to either sell or minimize the operating costs of the Company's non-core properties. These properties are generally small working interests which produce only moderate cash flows, have higher operating costs or are in non-focus areas. This structure allows the main operating group to concentrate on core properties which provide a larger return to the Company. To date, NCO has sold a number of its non-core properties and the funds are being reinvested to acquire reserves or for exploration and development activities which should enhance the Company's reserve base. During 1992, NCO disposed of 34 non-core properties for a total of $18.7 million.

Certain risks are inherent to the operation of oil and gas assets including exploration, environmental and governmental risks. Exploration risks pertain to the capital intensive nature of the industry which requires that a large portion of the free cash flow generated from operations be reinvested to replace produced reserves. A lack of success in exploration efforts can seriously impact the production capability and reserve positions of a company. As NCO is focusing its exploration efforts in the mature Western Canadian Sedimentary Basin, exploration success will continue to become more difficult.

The oil and gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on a release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires the well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and breach of such requirements may result in the imposition of material fines and penalties.

A distinct characteristic of the oil and gas industry is its relationship with the various governments who share industry profits through crown royalties. As government deficits continue to rise, the pressure to increase government revenues could have a large impact on the cash flows of oil and gas companies. While governments have been cognizant of the problems faced by the industry and have reduced royalty rates in recent years, an upturn in the industry may attract higher royalty levels from governments.

The oil and gas industry is highly competitive and companies compete for prospective exploration and semi-proven acreage, and the acquisition of proven reserves. The success of a company depends, to a significant degree, on its ability to maximize the cash flow from existing and newly found natural gas and crude oil reserves in order to maintain or increase its relative position within the industry. The achievement of this objective is contingent upon, but not limited to, factors such as a company's success in finding or acquiring commercial reserves, developing and placing these reserves on production, product prices, demand for natural gas and crude oil versus alternative forms of energy, adequate production and transportation facilities, the ability to market production and various government policies. Some of these factors are often beyond the control of a company and are influenced by both domestic and world economic and political pressures that can have a significant impact on the business of a company.

Natural Gas Production

The following table shows NCO's total production (before royalties) and revenues (after royalties), derived from the sale of natural gas, and the average netback.

	Years Ended December 31	
	1992	1991
Production (mmcf)	86,872	85,528
Production per day (mmcfd)	237.4	234.3
Revenues ($ millions)	98.3	99.3
Average price ($/mcf)	1.31	1.41
Average royalty ($/mcf)	0.17	0.25
Average lifting cost ($/mcf)	0.37	0.36
Netback ($/mcf)	0.77	0.80

Natural gas production averaged 237.4 mmcfd in 1992, a one percent increase over 1991 production levels. The increase was due primarily to the addition of production from the Progress area (8.3 mmcfd for the full year) beginning in July 1992, and higher production from the Lashburn/Poundmaker and Cactus Lake areas of Saskatchewan. These increases were partially offset by property divestments and pipeline restrictions during 1992. The average wellhead price of $1.31 per mcf was seven percent lower than the 1991 average price of $1.41 per mcf and resulted from the further softening of gas markets in eastern Canada as a result of surplus supply in western Canada. The negative effects of the excess supply situation were partially offset by increased exports to the U.S. and increased demand in western Canada and the northwest U.S. due to severe cold weather late in the year.

NCO's natural gas netback was $0.77 per mcf in 1992, four percent lower than the 1991 netback of $0.80 per mcf. The previously mentioned drop in natural gas prices was offset by a 32 percent drop in per mcf royalty rates. Higher Alberta government crown royalty deductions and lower Saskatchewan crown royalty rates were the major causes of declines in Crown royalties.

Natural Gas Production by Area

	1992	1991
	(mmcfd)	
Saskatchewan		
Hatton (Horsham)	74.5	81.9
Sand Hills/Maple Creek	12.4	14.9
Lashburn/Poundmaker (St. Walburg)	12.0	8.4
Cactus Lake	4.3	0.7
Other	5.7	5.4
	108.9	111.3
Alberta		
Birch Wavy	26.9	25.8
Medicine Hat	15.0	20.5
Knopcik	14.0	15.5
Liege/Saleski	11.2	11.7
Progress	8.3	–
Greater Cache	6.2	4.8
Kaybob	5.3	7.5
Delia	4.2	3.8
Rochester/Westlock	2.7	4.7
Medicine Lodge	2.6	–
Whitecourt	2.6	3.6
Bear River	2.2	2.3
Other	26.6	20.7
Thunder Creek, British Columbia	0.7	2.1
	128.5	123.0
Total	237.4	234.3

The majority of NCO's natural gas production in the Province of Saskatchewan comes from the Hatton and Sand Hills/Maple Creek areas in the southwestern part of the Province where the Company holds a working interest in excess of 90 percent. Saskatchewan production was 108.9 mmcfd in 1992, a decline of 2.4 mmcfd over 1991 levels due mainly to reduced deliverability from the Hatton properties which was partially offset by new production from Cactus Lake and increased deliverability at Lashburn/Poundmaker. A new five mmcfd facility at Tangleflags came on production late in 1992. Sales within Saskatchewan were to SaskEnergy Incorporated ("SaskEnergy") and various other consumers, primarily on short term contracts, with the remainder sold to consumers in eastern Canada at varied volumes and prices. Long term natural gas contracts sourced from Saskatchewan include those with Midland Cogeneration Gas Company and Consumers Power Company for contract periods of 10 to 12 years. The average take for these contracts was 12.0 mmcfd in 1992 (1991 – 12.3 mmcfd).

NCO's natural gas production in the Province of Alberta increased by 5.5 mmcfd in 1992 primarily as a result of the Progress acquisition which added 8.3 mmcfd to the full year's production levels (19 mmcfd for five months). This production increase was partially offset by volume reductions resulting from pipeline restrictions, shut-in production at Thunder Creek due to a workover, and the divestment of non-core properties. Declining deliverability from the Company's more mature properties, particularly in the Medicine Hat area, caused further reductions to production.

Approximately 39 percent of the Company's Alberta natural gas production was sold to major aggregators in 1992. A total of 33 mmcfd (1991 – 33 mmcfd) of the Company's production was sold to WGML under a number of contracts which extend over the life of the reserves and/or take-or-pay contracts. NCO's other major gas purchaser in Alberta is PAG, with sales of 17 mmcfd in 1992 which is consistent with the 1991 figure of 18 mmcfd. The remainder of the Company's Alberta production was sold directly to consumers in eastern Canada and the United States, the majority at short term and spot market prices.

Crude Oil and NGLs Production

The following table shows NCO's total production (before royalties) and revenues (after royalties), derived from the sale of crude oil and NGLs, and the average netback.

	Years Ended December 31	
	1992	1991
Production (mbbls)	2,242.7	2,390.3
Production (bpd)	6,128	6,549
Revenues ($ millions)	36.6	35.9
Average price ($/bbl)	19.07	17.94
Average royalty ($/bbl)	2.75	2.92
Average lifting cost ($/bbl)	4.75	4.66
Netback ($/bbl)	11.57	10.36

Crude oil and NGLs production averaged 6,128 bpd in 1992, a six percent decline from 1991 levels. New production from wells in the Little Bow South, Long Coulee, West Pembina and Progress areas was offset by declining deliverability from some of the Company's more mature fields, particularly Rainbow and Shekilie, and the divestment of non-core producing properties. Pipeline shipping restrictions during 1992 also had a negative impact on production.

The netback for crude oil and NGLs increased 12 percent from $10.36 per barrel in 1991 to $11.57 per barrel in 1992 due primarily to the narrowing of differentials between light and medium crudes and the weakening of the Canadian dollar. The netback was positively affected by a six percent reduction in per barrel crude oil and NGLs royalty rates. Operating costs, on a per barrel basis, increased by two percent from 1991 to 1992, while total operating costs declined by four percent in 1992.

Crude Oil and NGLs Production by Area

	1992	1991
	(bpd)	
Saskatchewan		
Inglenook	250	301
Plato	242	312
Other	31	119
	523	732
Alberta		
Rainbow	822	941
Little Bow South	658	635
Taber North	630	620
Knopcik	572	605
Grassy Lake	435	486
Progress	356	–
Long Coulee	274	227
Shekilie	250	412
Mitsue	180	166
West Pembina	150	70
Clear Hills	89	48
Other	1,189	1,607
	5,605	5,817
Total	6,128	6,549

The Company sells its crude oil at the plant gate to refiners and/or marketers. The buyer's prices are tied to an industry posted price in Edmonton which is adjusted for quality. The value of the monthly Edmonton posting is driven by the netback value of West Texas Intermediate crude oil at Cushing, Oklahoma. NGLs are sold on the basis of industry posted prices in Edmonton.

Exploration and Development

Petroleum and Natural Gas Reserves

The following tables show the Company's petroleum and natural gas reserves at January 1, 1993. NCO's core reserves were evaluated by Sproule Associates Limited ("Sproule"), independent engineering consultants of Calgary, Alberta, and non-core reserves were evaluated internally by NCO's engineers. Core properties accounted for approximately 84 percent of total proven reserves at January 1, 1993. See Note 16 to the Consolidated Financial Statements for certain additional constant price case reserve information.

The reserve information that follows is presented in two cases. The constant price case is prepared using constant year end 1992 prices and cost assumptions adjusted for future fixed price contracts currently held by the Company, while the escalating price case uses future price forecasts and cost assumptions. The forecast of future prices is based on the assumptions of Sproule adjusted for future fixed priced contracts held by the Company. The differences between the two cases arise from the improved economics of the escalated dollar case.

In addition, the following tables set forth certain information relating to the estimated future net revenues, including Alberta Royalty Tax Credit ("Royalty Tax Credits"), of the Company's natural gas, crude oil and NGLs reserves. The estimated future net revenue information is based upon a report ("Sproule Report"), dated January 26, 1993, and prepared by Sproule and a separate report prepared internally by NCO's engineers ("NCO Report"). Assumptions and qualifications contained in the Sproule Report relating to prices, costs and inflation are set forth in the notes following the tables. The NCO Report is based on Sproule's price forecasts and cost inflation schedules. All evaluations have been stated prior to any provision for income taxes, interest costs or general and administrative costs and after deduction of estimated future capital expenditures. **It should not be assumed that the estimated future net production revenues represent the fair market value of the reserves of the Company.**

Constant Price Case

	Gross Reserves (1)		Net Reserves (1)	
	Crude Oil & NGLs (mmbbls)	Natural Gas (bcf)	Crude Oil & NGLs (mmbbls)	Natural Gas (bcf)
Proven reserves (2)				
Developed producing (3)	13.8	593.2	11.2	501.4
Developed non-producing (4)	0.7	123.0	0.5	104.0
Undeveloped (5)	1.4	222.1	1.1	188.6
Total proven	15.9	938.3	12.8	794.0
Probable additional (6)	1.4	54.7	1.2	45.6
Total	17.3	993.0	14.0	839.6

Escalated Price Case

	Gross Reserves (1)		Net Reserves (1)	
	Crude Oil & NGLs (mmbbls)	Natural Gas (bcf)	Crude Oil & NGLs (mmbbls)	Natural Gas (bcf)
Proven reserves (2)				
Developed producing (3)	14.1	634.9	11.4	523.8
Developed non-producing (4)	0.7	125.3	0.5	100.8
Undeveloped (5)	1.5	225.7	1.1	184.7
Total proven	16.3	985.9	13.0	809.3
Probable additional (6)	1.1	58.5	0.9	47.2
Total	17.4	1,044.4	13.9	856.5

Present Worth of Future Net Cash Flow Before Income Taxes Based on Escalating Price Assumptions

	Undiscounted	10% Discounted	15% Discounted	20% Discounted
		($ millions)		
Proven reserves (2)				
Developed producing (3)	1,231.0	575.0	454.5	377.1
Developed non-producing (4)	217.2	68.3	45.8	32.6
Undeveloped (5)	411.6	137.5	88.9	59.9
Total proven	1,859.8	780.8	589.2	469.6
Probable additional (6)	136.1	38.9	26.5	19.2
	1,995.9	819.7	615.7	488.8
Royalty tax credits	27.7	13.7	10.5	8.3
Total	2,023.6	833.4	626.2	497.1

Notes

(1) "Gross reserves" are defined as the Company's working interest share of recoverable hydrocarbons before the deduction of any royalties. "Net reserves" are gross reserves less any and all royalties payable to outside parties.

(2) "Proven reserves" are considered to be those reserves estimated as recoverable, under current technology and, in the constant price case, existing economic conditions, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir.

(3) "Proven developed producing reserves" are those proven reserves that are actually on production or, if not producing, could be recovered from existing wells or facilities and where the reasons for the current non-producing status is the choice of the owner rather than the lack of markets or some other reasons. An illustration of such a situation is where a well or zone is capable but is shut-in because its deliverability is not required to meet contract commitments.

(4) "Proven developed non-producing reserves" are those proven reserves that are not currently producing either due to a lack of facilities and/or markets.

(5) "Proven undeveloped reserves" are proven non-producing wells which are expected to be recovered from new wells to be drilled or from existing wells where a major expenditure is required for workover operations, completions or surface facilities.

(6) "Probable additional reserves" means those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proven under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes are calculated as the increased recovery, over and above those that are estimated as proven reserves, which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

(7) The escalating price assumptions assume the continuation of existing federal and provincial laws and regulations, give effect to forecast changes in wellhead selling prices and take into account inflation with respect to future operating and capital costs. The natural gas, natural gas liquids and crude oil prices used in the Sproule and NCO Reports are based on the wellhead prices set forth below.

Average Price Forecasts

Years	Natural Gas ($/mcf)	Crude Oil ($/bbl)	NGLs ($/bbl)
1993	1.33	20.26	17.39
1994	1.42	21.20	18.36
1995	1.54	22.46	19.60
1996	1.72	23.92	20.89
1997	2.00	25.48	22.14
1998	2.29	27.04	23.45
1999	2.55	28.85	24.90
2000	2.81	30.79	26.51
2001	3.06	32.86	27.91
2002	3.29	35.17	29.60
2003	3.49	37.63	31.23
2004	3.71	39.56	32.52
2005	3.92	41.29	33.77
Escalated thereafter at	4.5%	4.0%	4.0%

In preparation of the Sproule and NCO Reports, the following escalations, originally supplied by Sproule, were applied to the actual costs and capital at the end of 1992.

	Escalation Factors Costs & Capital
1993	3.0%
1994	3.5%
Thereafter	4.0%

The following table shows the changes to the Company's gross proven reserves in 1992.

	Constant Price Case 1992		Escalated Price Case 1992	
	Crude Oil & NGLs (mmbbls)	Natural Gas (bcf)	Crude Oil & NGLs (mmbbls)	Natural Gas (bcf)
Beginning of year	14.2	991.0	14.3	996.9
Revisions of previous estimates	0.1	(47.9)	0.4	(6.2)
Purchase of minerals-in-place	4.8	110.8	4.8	110.8
Sale of minerals-in-place	(1.8)	(42.5)	(1.8)	(42.5)
Extensions and discoveries	0.8	13.8	0.8	13.8
Production	(2.2)	(86.9)	(2.2)	(86.9)
End of year	15.9	938.3	16.3	985.9

Proven crude oil and NGLs reserves additions from extensions and discoveries were composed solely of crude oil and totalled 0.8 mmbbls during 1992. Crude oil additions were mainly in the Little Bow and West Pembina areas of Alberta. Proven natural gas reserve additions from extensions and discoveries were 13.8 bcf, primarily from the Hatton, and Sand Hills areas of Saskatchewan and Liege in Alberta.

The acquisition of the Progress property in northern Alberta resulted in the addition of 109.9 bcf of proven natural gas and 4.5 mmbbls of proven crude oil and NGLs to the Company's reserve base.

As a result of the Company's asset rationalization program, 1.8 mmbbls of crude oil and NGLs and 42.5 bcf of proven natural gas reserves were sold during 1992. These dispositions involved 34 properties with only three of the transactions valued at over $2 million. The most notable disposition was the Delia property in south central Alberta where the Company sold 9.5 bcf of natural gas for $6.5 million late in 1992.

Proven natural gas reserves, on a constant dollar basis, were revised downward by 47.9 bcf in the fourth quarter of 1992 as a result of the year end evaluation performed by Sproule and NCO's engineers. The downward revision was primarily in the BirchWavy area of central Alberta and certain shallow gas areas of Saskatchewan as a result of constant pricing assumptions which caused reserves at the end of their production life to become uneconomic to produce. Under the escalated price evaluation, long life, low deliverability reserves become more economic and account for the large difference in revisions under the escalated as opposed to constant price evaluation.

Land Position

During 1992, NCO acquired 67,100 gross (59,200 net) acres of land at Crown land sales and from freehold lease owners at an aggregate cost of $2.7 million. In 1991, land purchases involved 266,100 gross (178,500 net) acres of land for a total cost of $11.6 million. Average prices paid were $46 per acre in Alberta and $40 per acre in Saskatchewan, as compared to $68 per acre and $56 per acre respectively in 1991. The net undeveloped acreage indicated below, contains 550,000 acres in core exploration areas, including 128,000 acres related to a major land farm-in by the Company during 1992.

	Land Holdings as of December 31, 1992			
	Developed Acres (1)		Undeveloped Acres (2)	
	Gross (3)	Net (4)	Gross (3)	Net (4)
Alberta	1,738,110	678,781	1,882,488	861,144
Saskatchewan	538,934	305,335	628,399	384,189
British Columbia	40,743	14,655	64,861	40,628
Total	2,317,787	998,771	2,575,748	1,285,961

(1) "Developed acres" are those defined by the drilling spacing unit or by acreage to which recoverable reserves have been assigned.
(2) "Undeveloped acres" means exploratory acreage or acreage to which no recoverable reserves have been assigned.
(3) "Gross acres" means the total acres in which the Company has a working interest.
(4) "Net acres" means the aggregate of the Company's interest in each gross acre.

Crude Oil and Natural Gas Wells

The following table summarizes NCO's interests as at December 31, 1992, in crude oil and natural gas wells which were producing or which the Company considers to be capable of production. All wells included in this table that were not producing were shut-in natural gas wells which are located within 25 miles of transmission facilities.

	Natural Gas Wells		Crude Oil Wells	
	Gross (1)	Net (2)	Gross (1)	Net (2)
Alberta	3,045	1,536	419	168
Saskatchewan	1,427	1,033	227	167
British Columbia	19	7	39	2
Total	4,491	2,576	685	337

(1) "Gross wells" means the total wells in which the Company has a working interest.
(2) "Net wells" means the aggregate of the Company's percentage interest in each gross well.

Drilling

NCO continued its policy of assuming the role of operator wherever possible and at December 31, 1992, operated 84 percent and 85 percent of its natural gas and crude oil and NGLs production respectively. The Company participated in the drilling of 97 gross (62.0 net) wells during 1992 compared to 211 gross (114.2 net) during 1991. Exploration and development drilling expenditures totalled $22.7 million (1991 – $27.5 million) while seismic costs totalled $3.2 million (1991 – $8.3 million). Drilling costs on a per well basis during 1992 increased over 1991 as a result of the shift from shallow wells to deeper wells which is consistent with NCO's strategy to find longer life, higher deliverability reserve pools. The following table shows the Company's drilling results for 1992 and 1991.

Exploratory Drilling

	Years Ended December 31			
	1992		1991	
	Gross	Net	Gross	Net
Natural gas wells	18	13.5	47	29.4
Crude oil wells	11	7.6	13	6.7
Dry and abandoned	10	6.6	38	21.0
Total	39	27.7	98	57.1
Success ratio		76%		63%

Development Drilling

	Years Ended December 31			
	1992		1991	
	Gross	Net	Gross	Net
Natural gas wells	50	30.3	100	54.1
Crude oil wells	5	3.0	7	1.5
Dry and abandoned	3	1.0	6	1.5
Total	58	34.3	113	57.1
Success ratio		97%		97%
Overall success ratio (1)		88%		80%

(1) The high overall success ratio is due to the high success of the development drilling programs and the fact several exploration wells were cased in late December 1992, yet no reserves were assigned by Sproule as the wells had not been tested.

To January 31, 1993, the Company had drilled an aggregate four gross (2.3 net) wells, all located in Alberta.

Capital Expenditures

Costs incurred for oil and gas property acquisitions, exploration, development and facilities for the years ended December 31, are shown below.

	1992	1991
	($ millions)	
Acquisition of proven properties	76.9	2.6
Divestitures	(18.7)	(0.8)
Exploration	20.7	31.8
Development	18.0	25.1
Acquisition of unproven properties	2.7	15.3
	99.6	74.0

Marketing Activities

Risks and Strategic Analysis

NCO, through its wholly-owned subsidiaries, purchases, transports and direct markets both corporate and third party natural gas throughout North America. Marketing activities continue to diversify and expand in response to NCO's needs and changes in the marketplace. Marketing activities are carried out from the Company's head office in Calgary and from regional offices located in Toronto, Ontario; Regina, Saskatchewan; Orange, California; and Houston, Texas.

The Company negotiates and administers natural gas contracts with system aggregators and direct buyers. It controls a secure and extensive natural gas supply portfolio and holds firm transportation on several major North American pipeline systems. NCO's current supply portfolio includes contractual arrangements with over 60 independent producers, marketers and several large multinational energy companies.

Over the past five years, NCO has developed a portfolio of natural gas sales contracts and transportation capacity which has given the Company a presence in the natural gas marketing business. While the fundamental purpose of the Company's marketing activities is to enhance the value of its natural gas reserve base, the strategy required to meet this objective is a forward looking approach to establish markets for future, as well as current production. This long term perspective of the North American marketplace is the Company's basis for decisions on issues such as the decontracting of production from system aggregators in favour of direct marketing, or the contracting of strategic transportation space.

NCO's approach is to hold markets which exceed current corporate production capabilities through the use of third party gas in order to secure markets for future corporate production. During 1992, the Company's sales to direct markets exceeded the amount of corporate natural gas available to those markets by 336 mmcfd and the Company purchased natural gas from third parties in order to supply these markets. NCO's strategy is, in general, to secure natural gas supply to match its delivery obligations in order to secure a profit margin and minimize the risk around fluctuations in the price of natural gas purchased on a spot basis. However, the Company has left certain delivery obligations exposed to the spot market in order to allow for operational flexibility within its sales and supply portfolio. As a result of this exposure to the spot market, losses occurred late in 1992 and into 1993 due to large increases in natural gas prices which occurred during this time frame. (See Item 5 of this document for related information.)

In conjunction with the management of natural gas supply and demand, the Company holds firm transportation capacity on various natural gas pipelines in North America. (See "Transportation Agreements".) The Company is obligated to pay for this capacity regardless of utilization. Should the dynamics of the marketplace change, making it undesirable to buy natural gas from one location and transport it to another for sale, the Company would still be obligated to pay for its firm transportation capacity. At the present time, NCO has some long term contracts to utilize a portion of its transportation portfolio, however, a portion of the Company's firm transportation capacity has the potential of not being fully utilized. The Company currently believes these risks are an inherent part of pursuing its stated strategies and are manageable on an ongoing basis.

Based on the January 1, 1993 reserve evaluations, the Company currently possesses the corporate production capability to meet all of its long term contractual obligations.

Regulatory Environment

On October 31, 1985, the Government of Canada and the Governments of Alberta, British Columbia and Saskatchewan reached a new Agreement on Natural Gas Markets and Prices ("Agreement"). As set out in the Agreement, the prices for natural gas are to be determined by negotiation between buyers and sellers. Suppliers are free to market natural gas directly to end-users. Direct sales of natural gas exported from Alberta require a Removal Permit issued by the Energy Resources Conservation Board, and Saskatchewan exports require a Removal Permit issued by Saskatchewan Energy and Mines. With regard to exports from Canada, the National Energy Board's ("NEB") role in considering applications to export natural gas from Canada continues to be amended. Long term exports are presently scrutinized by the NEB through a process called the Market Based Procedure ("MBP") which focuses on the commercial terms and conditions associated with prospective export contracts. The NEB presumes that gas contracts entered into on an arms length basis are in both the public and private interest.

The MBP is generally intended to permit the market to operate freely, however, the NEB reserves the right to intervene if it believes increased exports could cause imminent difficulty in meeting Canadian gas requirements. The complaints procedure exists to ensure that Canadians are able to obtain additional gas supplies on contractual terms and conditions similar to those in an export proposal. Furthermore, the NEB examines whether a proposed export will likely cause Canadians difficulty in meeting their energy requirements at fair market prices. For short term exports of natural gas (two years or less), there are no volumetric limitations, although an order is required from the NEB. Short term approvals are routinely issued by the NEB and in practice, the NEB does not review pricing information in respect thereof.

However, the NEB recently announced various interim measures to prevent short term exports from potentially displacing exports under long term contracts to northern California. The interim measures are likely to remain in place until the A&S restructuring is complete.

In the United States, the Federal Energy Regulatory Commission ("FERC") issued Order 636 during 1992. Order 636 represents a fundamental restructuring of the natural gas industry in the U.S. and is intended to improve the competitive structure of the natural gas industry. FERC believes this goal can be achieved by separating, or unbundling, an interstate pipeline's sales service from its transportation service. The effect will be to substantially reduce the traditional merchant function of an interstate pipeline. The interstate will no longer sell gas, and will no longer need to purchase substantial supplies of gas. The impact on the Canadian natural gas industry of this fundamental change in the U.S. is uncertain.

Natural Gas Pricing Environment

As a result of deregulation, the Company's natural gas production is sold to three basic markets: 1) traditional system aggregators; 2) direct end-use markets and; 3) sales made on behalf of the Company by third party property operators. Within the category of traditional system aggregators, the Company's three major purchasers are WGML and PAG in Alberta, and SaskEnergy in Saskatchewan.

Effective November 1, 1986, WGML negotiated the Netback Pricing Agreement with its suppliers. Under the terms of this Agreement, the price that producers receive for natural gas reflects the price WGML receives minus certain costs primarily being transportation costs, take-or-pay costs and a WGML marketing, operating and administration fee. The Netback Pricing Agreement expired in 1988. The Company has negotiated a new Netback Pricing Agreement with WGML following similar terms as the previous agreement which remains in effect for the life of the contracted reserves.

Effective November 1, 1986, PAG negotiated the Market Sensitive Pricing Agreement with its suppliers. Under the terms of this Agreement, the price that producers receive reflects the price that PAG receives less transportation costs and a return for PAG. This Agreement expired November 1, 1988. Since then, the Company has entered into three amendments to the Market Sensitive Pricing Agreement with pricing provisions similar to the original agreement, the most recent of which will expire on October 31, 1993. As the reserves produced under the Market Sensitive Pricing Agreement are dedicated to PAG, the Company will continue to renegotiate this Agreement to the end of the life of the dedicated reserves.

NCO sales to SaskEnergy are currently subject to a fixed price agreement for a two year period ending October 31, 1993. NCO will be offered a new pricing agreement and has the right to initiate an arbitration process if the offered price is deemed unacceptable. The reserves produced under SaskEnergy contracts are fully dedicated, therefore this process will continue to the end of the economic life of the dedicated reserves.

As a result of NCO's efforts in the area of natural gas marketing, approximately 49 percent of the Company's natural gas production was sold to direct end-users in 1992 with a mix of short, medium and long term contracts. The end-users of this natural gas production are industrial consumers, local distribution companies, eastern Canadian core market purchasers and power cogeneration facilities. Pricing is determined through an arms length negotiation and is in part a result of the contract duration, supply and demand conditions, and the financial strength of the respective parties in relation to one another.

Sales made on behalf of NCO by third party operators, occur in situations where NCO has a minority working interest in a natural gas property, but elects not to market its share of the production. The sales made by these third party operators would be to a combination of direct and traditional markets. The volumes sold by third party operators represents a small portion of NCO's sales portfolio.

Natural Gas Sales

In 1992, NCO's natural gas sales totalled 573 mmcfd (1991 – 483 mmcfd). Of this total, 237 mmcfd (1991 – 234 mmcfd) was sold on behalf of NCO and 336 mmcfd (1991 – 249 mmcfd) on behalf of NCO's working interest partners and independent third party producers. The table below indicates the natural gas markets of the Company during 1992 and 1991.

Natural Gas Sales by Major Purchasers (1)

	Year Ended December 31	
	1992	1991
	(mmcfd)	
Long term		
Cogeneration	22	12
Utilities	16	13
WGML	33	33
SaskEnergy	50	24
PAG	17	18
Sold by third party operators	17	18
Other system sales	4	5
Medium/short term		
Eastern Canada	128	135
Alberta/Saskatchewan	58	66
United States	228	159
Total	573	483

(1) Sales in this table include both NCO corporate and third party natural gas.

The following table indicates the major direct long term sales contracts the Company holds in addition to its contracts with traditional natural gas purchasers which would include WGML, PAG and SaskEnergy.

Long Term Sales Contracts	Delivery Commencement Date	Initial Term Years	Contract Volume
Federal Paper Board Cogeneration Project (1)	Jan. 1/89	5	5.5 mmcfd
Southern California Gas Company	Nov. 1/89	5	50 mmcfd
Consumers Power Company	Nov. 1/90	12	10 mmcfd
Centra Gas Cogen	Nov. 1/90	15	10.7 mmcfd (2)
Midland Cogeneration Gas Company	Nov. 1/90	10	10 mmcfd
Michigan Consolidated Gas	July 1/91	10	7.0 mmcfd
Syracuse Cogeneration Project (1)	June 17/92	20	8.4 mmcfd
Pasco Cogeneration Project (1)	July 1/93	15	21.5 mmcfd
Lake Cogeneration Project (1)	July 1/93	15	21.5 mmcfd
Kamine/Besicorp Natural Dam Project	Nov. 1/93	15	12 mmcfd
Kamine/Besicorp Syracuse Project	Nov. 1/93	15	16 mmcfd
Kamine/Besicorp Beaver Falls Project	Nov. 1/94 (3)	15	16 mmcfd

The Company's long term contracts are supplied through a combination of its own production and secure third party purchases.

(1) The Company holds an equity interest in these power cogeneration projects.
(2) Renegotiated in 1992.
(3) Start-up date delayed.

Transportation Agreements

NCO manages and holds transportation agreements with major transporters of natural gas in Canada and the U.S. and has the capability of moving Canadian natural gas to key markets in North America. Construction of the Pacific Gas Transmission Company ("PGT") expansion to California, on which the Company holds 59 mmcfd of firm transportation space, is expected to be completed in late 1993. In addition, the NOVA pipeline in Alberta and TransGas pipeline in Saskatchewan have responded to requests from producers by expanding to accommodate new production from Alberta and Saskatchewan which is destined for eastern Canada or the United States. These expansion projects will significantly enhance the Canadian producers' ability to access downstream markets in eastern Canada, the northeastern U.S., California and the mid-west U.S.

In addition to the pipeline capacity that the Company controls on the NOVA, TransGas and TransCanada systems, NCO's transportation portfolio includes the following.

NCO Pipeline Capacity	**Remaining Term of Agreement**
50 mmcfd of firm space on Foothills Pipeline Ltd.	2 years (1)
50 mmcfd of firm space on Northern Border Pipeline Company	10 years
59 mmcfd of firm space on the Pacific Gas Transmission Company expansion	30 years
59 mmcfd of firm space on Alberta Natural Gas Company Ltd.	15 years
7 mmcfd of firm space on Great Lakes Gas Transmission Company	13 years
7 mmcfd of firm space on ANR Pipeline Company	15 years

(1) The Company has made an application for extension to match this capacity with Northern Border.

Power Cogeneration Activities

Risks and Strategic Analysis

The Company has identified power cogeneration as a potential growth market for the sale of natural gas in North America. In response to this opportunity, the Company has established expertise in the business and has invested in five cogeneration projects, three of which are operational and two of which are under construction.

The integration of power cogeneration activities with exploration, production and marketing activities is an important element in the Company's efforts to maximize the value of its natural gas reserves and to optimize transportation capacity. As the primary purpose for participating in the power cogeneration industry is to secure additional natural gas markets, the Company will only make an equity investment in a project if it participates in the related long term natural gas supply to the project. These equity investments are expected to provide an adequate rate-of-return and to be an additional source of cash flow and earnings. NCO seeks to obtain, to the extent possible, maximum non-recourse financing on power cogeneration projects thereby minimizing its equity contribution and financial exposure. The Company prefers an equity position of 50 percent or less in any given project while maintaining operating control.

NCO is a managing general partner for four of the five cogeneration projects in which it currently holds an equity interest. It is the intention of the Company to continue to assume the role of managing general partner for new projects in order to utilize its expertise in the operation of cogeneration facilities. The Company is able to protect its equity interests by maintaining control as well as earning fees associated with managing these activities. The Company has found that the fees earned for development and management activities have generally covered the administrative costs of the business. As such, the costs of generating additional markets for corporate and third party natural gas have more or less been limited to the cost of equity contributions which in turn are expected to earn adequate rates-of-return.

The success of a power cogeneration project in the U.S. is dependent upon several factors, including an increase in electrical rates over time to match increasing operating costs, and the continued financial stability of the steam host in order to maintain a Qualifying Facility ("QF") status under applicable legislation. By maintaining a QF status, a project is assured that the applicable utilities will purchase the allowable electrical output. The highly regulated nature of the cogeneration industry presents several risks including changes to legislation which currently obligates utilities to purchase electricity from such projects. However, the Company believes the cogeneration industry provides low cost power to the general public and as such QF projects should continue to be protected by legislation in various jurisdictions in the U.S. Before investing in a cogeneration project, the Company carefully analyses these risks.

NCO has established special subsidiary companies to hold its cogeneration equity investments. NCO's corporate liability is thereby limited to its equity investment on a project-by-project basis. In addition, except as set forth below, the terms of financing for each project provide that the lender will have no recourse for payment beyond the assets of the project. However, in conjunction with obtaining financing for the projects, NCO has guaranteed certain financial and risk obligations, in particular fuel supply obligations. These guarantees have exposed the Company to certain contingent liabilities which would not normally exist as a result of the non-recourse financing and special purpose subsidiary arrangements. Management believes the likelihood of financial losses as a result of these guarantees is minimal at this time.

Power Cogeneration Investments

The Federal Paper Board project is an operating 26 megawatt, natural gas-fired facility located at Commerce, California, in which the Company is a 30 percent owner, co-general partner and fuel supplier. The facility produces steam which is sold to an adjacent paper board plant and electricity which is sold under a 20 year contract to Southern California Edison Company. NCO has contracted to supply up to 5.5 mmcfd of natural gas to meet the plant's operating requirements pursuant to a five year extendible contract which is up for renewal in 1996. Financing is provided through non-recourse debt. This project is currently meeting its non-recourse financing obligations however, future projections indicate the project will be unable to do so in 1994. To reflect this financial uncertainty, the Company wrote-down the value of its investment in this project by $2.2 million during 1992.

The Ada project is an operating 29.4 megawatt, natural gas-fired facility located at Ada, Michigan. The Company holds a 50 percent economic interest in the project consisting of a one percent general partnership interest and a performance based leasehold interest. The project is financed through non-recourse debt. Electricity from the project is sold to Consumers Power Company of Jackson, Michigan, and the steam from the project is sold to Amway Corporation, both under 35 year sales agreements.

The Syracuse project is an 80 megawatt facility located in Syracuse, New York which commenced commercial operations in July 1992. The project was financed through non-recourse debt and in December 1992, at the time of the construction loan term conversion, the Company reduced its equity position in Syracuse from 83 percent to 33 percent by introducing a new equity partner who contributed U.S.$12.5 million. NCO's interest is composed of a one percent general partnership interest and a 32 percent limited partnership interest. NCO is committed to supplying approximately 50 bcf of the natural gas required by the project over the next 16 to 20 years for which the Company received a prepayment of $42.2 million during 1991. Under the gas prepayment agreement, the Syracuse project pays for the transportation, operating costs and royalties, subject to certain limits, and NCO has the option of supplying the natural gas to the project through corporate production or the use of third party supply. Steam generated by the project is sold to Syracuse University and the electricity is sold to the Niagara Mohawk Power Corporation, both under 40 year contracts.

The Pasco project is a 106 megawatt, U.S.$103.4 million facility currently under construction near Dade City, Florida. The Company holds 50 percent of the equity in the project composed of a one percent general partnership interest and a 49 percent limited partnership interest. NCO's equity commitment totals U.S.$5.4 million and will be contributed upon completion of construction according to the terms of a non-recourse debt financing agreement. In addition to its equity participation, NCO will also supply approximately 21.5 mmcfd of natural gas to the project over a 15 year period with the option of using either corporate production or third party supply. The steam generated from the project will be sold to Lykes Pasco, Inc. for its citrus processing operation while the electricity will be sold to Florida Power Corporation, both under 20 year contracts. Construction on the project commenced in early 1992 and commercial start-up is expected in mid-1993.

Under the fuel supply obligation guarantees given by NCO to obtain the non-recourse financing for the Pasco project, the Company potentially could have to assume the full non-recourse debt of the Pasco project. This debt is currently estimated to be U.S.$92.6 million. The assumption of this debt would be required if the project lender reasonably rejects the natural gas supply and transportation portfolio presented to them by NCO. The natural gas supply and transportation portfolio is currently before the project lender for review and the Company believes that this proposal will be approved.

The Lake project is a 106 megawatt cogeneration facility currently under construction near Umatilla, Florida. The Company expects to spend U.S.$100 million in development and construction costs. Construction financing arrangements, which were completed in August 1992, consist of a $100 million non-recourse construction loan. Upon completion, the project will be sold to and leased back from the construction lender under an extendible 16 year agreement. The steam will be sold to Golden Gem Growers, a local fruit processing co-operative, and the electricity to Florida Power Corporation, both under 20 year contracts. The Company holds 100 percent of the equity in this project and will supply the approximate 21.5 mmcfd of natural gas required to operate the plant over a 15 year period with the option of using either corporate production or third party supply. Construction commenced in early 1992 with commercial start-up scheduled for mid-1993.

As part of the sale and leaseback arrangement related to the Lake Project, the Company has undertaken certain guarantees to the lender. These guarantees fall under two broad categories namely equity and operational. The equity guarantee is such that should the utility's price of coal be below a certain specified level at the date of the sale and leaseback, NCO may be required to contribute equity or reduce the gas price charged to the project to ensure minimum and average lease coverage ratios are maintained throughout the term of the lease based on a specified set of assumptions. The maximum equity contribution required under the guaranty is U.S.$15 million.

Under the operational guarantee, NCO has elected to use a corporate guarantee to support the project's ability to meet a portion of the lease payments over the term of the lease. This exposure was approximately U.S.$18 million at the time of conversion, reducing to U.S.$10 million after three years and continuing as such for the term of the lease. Without a corporate guarantee, it would normally be a requirement of the lender to escrow these funds from future cash flow from the project and hold them for the term of the lease. This would reduce the distribution cash flow and lower the return NCO receives from the project. The lender is satisfied that NCO's financial position is strong enough such that a corporate guarantee is adequate.

In January 1993, the Company announced arrangements with ARCO GAS, a major U.S. energy company, to supply approximately 31 mmcfd of the total 43 mmcfd of fuel required for the Pasco and Lake projects over a 15 year period.

Natural Gas Pipelines

The Company owns two pipeline systems, one which transports natural gas to customers in Alberta and one which is not currently in operation. The operating pipeline is a 136 mile, ten inch diameter mainline with several miles of connecting lateral pipeline in the Wabamun-Hinton area of west central Alberta. The other is a 1.7 mile, four inch diameter line which served an industrial customer in the Balzac area north of Calgary. During 1992, the industrial customer ceased operations and at year end 1992, no volumes were flowing on the Balzac line.

The operation of the Wabamun-Hinton pipeline system is unrelated to the Company's natural gas production activities, although new natural gas reserves have been established along the line which will be transported into the NOVA system through this line. Revenues generated from pipeline activities are composed of transmission fees charged for the transportation of natural gas through the system and the sale of third party supply to others. The four principal transmission customers on the Wabamun-Hinton pipeline are Weldwood of Canada Limited for its pulp mill at Hinton, Northwestern Utilities Limited for distribution to its customers, and two upstream natural gas producers for the transportation from wells to the NOVA connection point at Carrot Creek. The transmission contracts for these four major customers provided for firm service commitments during 1992 totalling 46 mmcfd or $1.5 million per year.

In 1992, the average throughput of the Wabamun-Hinton pipeline system was 41.9 mmcfd (1991 – 38.5 mmcfd) for a total of 15.3 bcf (1991 – 14.0 bcf) and the average throughput of the Balzac pipeline lateral during 1992 was 1.3 mmcfd (1991 – 2.3 mmcfd) for a total of 0.5 bcf (1991 – 0.8 bcf).

Polaris Mine Royalty Interest

The Company owns a 25 percent royalty interest in the total net proceeds of production from the Polaris Mine, a major world producer of lead and zinc which is located on Little Cornwallis Island in the Canadian Arctic. The ore body was discovered in the early 1960's by Bankeno Mines Limited, a company which NCO acquired in 1984. Bankeno transferred the ore body to Cominco Ltd. in 1971 for the purpose of developing the Mine while retaining the present 25 percent royalty interest. All costs incurred with respect to this Mine were accumulated and segregated over the years into production costs and development costs. The royalty interest agreement provides a formula for the payment of the royalty which was contingent upon the recovery of production and development costs by the Mine's operator, Cominco Ltd. These costs include developing the Mine, the initial start-up costs, the operating costs net of sales, together with interest incurred on these amounts. In 1992, payout of the accumulated costs occurred which resulted in higher royalty revenues of $10.6 million (1991 – $3.3 million).

An evaluation of the reserves of the Polaris Mine at January 1, 1993, was prepared by Strathcona Mineral Services Limited, independent engineering consultants of Toronto, Ontario. This evaluation indicated 10.6 million tonnes of proven and probable reserves of ore expected to be mined and milled over the next 11 to 12 years. According to this report, the average grade of the ore body anticipated to be recovered over this period of time is approximately 13 percent zinc and 3.5 percent lead. The grade and production of the Polaris ore body is anticipated to be relatively consistent over the reserve life.

Investment Activities

The Company's portfolio of investments, as at December 31, 1992, totalled $159.9 million and consisted of preferred and common shares having a book value of $94.9 million and a $65.0 million long term note receivable from American Express Canada Ltd. with which the Company deals at arm's length. The portfolio has fluctuated in size over the past several years depending on what surplus funds might be available and what funds were required for acquisitions in the oil and gas business such as the Brenda, Bankeno, Coseka and Progress transactions. The investment portfolio includes securities of related companies which vary in amounts from time to time. It is currently the Company's intention to utilize the proceeds from the repayment of the long term note receivable to retire debt. NCO's objective is to earn an acceptable rate-of-return from these investments without exposure to excessive capital risk. At December 31, 1992, the Company reclassified its holdings in preferred and common shares from short to long term.

For the five years ended December 31, 1992, the investment portfolio has regularly been built-up and liquidated to fund various acquisitions and to supplement internally generated cash flow for ongoing capital expenditures programs. The following table summarizes the major sources and uses of funds relating to the investment portfolio during this period.

	($ millions)
Balance, January 1, 1988 (including $65 million note receivable)	315.3
Increase in portfolio:	
Partial proceeds from common share issue (1989)	75.0
	390.3
Decreases in portfolio:	
Reinvestment in the oil and gas business (1988 – 1992)	47.3
Purchase of Brenda oil and gas marketing assets (1988)	31.5
Purchase of Bankeno minority interest (1990)	39.9
Acquisition of Coseka common shares and settlement of its debt (1990)	86.7
Purchase of Progress properties (1992)	25.0
Balance, December 31, 1992 (including $65 million note receivable)	159.9

Item 4: SUMMARY OF FINANCIAL INFORMATION

	Year Ended December 31				
	1992	1991	1990	1989	1988
	($ millions except per share amounts)				
Total revenues, net of royalties	375.7	328.8	290.2	337.7	236.6
Net earnings	11.0	16.9	32.8	29.0	31.4
Basic and fully diluted net earnings per common share (1)	0.12	0.25	0.64	0.58	0.71
Total assets (at end of year)	1,148.5	1,101.9	1,125.8	1,023.7	875.1
Long term obligations including redeemable preferred shares (at end of year)	351.5	333.8	294.4	287.4	322.0
Dividends per common share	0.20	0.20	0.20	0.20	0.20

Quarterly Financial Information (Unaudited)

	Three Months Ended			
	Dec. 31	Sept. 30	June 30	March 31
	($ millions except share amounts)			
1992				
Total revenues, net of royalties	120.2	89.2	88.3	78.0
Net earnings	0.4	4.6	4.1	1.9
Net earnings per common share (1) after preferred share dividends – basic	(0.03)	0.08	0.06	0.01
1991				
Total revenues, net of royalties	83.9	75.0	80.3	89.6
Net earnings	4.4	3.0	2.8	6.7
Net earnings per common share (1) after preferred share dividends – basic	0.07	0.03	0.02	0.13

(1) Fully diluted net earnings per common share for all the periods were inapplicable as none of the Company's convertible instruments were dilutive.

(2) In addition, other factors which have effected the comparability of the above data include the acquisition of Coseka and revisions to the Company's proven reserve estimates in 1991.

Dividends

During 1992 and 1991, the Board of Directors of NCO approved a dividend payment of $0.20 per common share per annum, payable semi-annually on June 30 and December 31. The Directors of the Company reevaluate the common share dividend payment on a semi-annual basis.

Dividends on Class A Preferred Shares Series 1, Class B Preferred Shares, Series 6 and 7, are paid quarterly on March 31, June 30, September 30, and December 31. The dividend payments for Class A Preferred Shares, Series 1, from March 31, 1991 to December 31, 1992 were: 54.25¢, 46.75¢, 42.50¢, 40.00¢, 34.25¢, 34.50¢, 30.00¢ and 33.00¢ respectively. Dividend payments per share on Class B Preferred Shares, Series 6 and 7, were 50.00¢ and 46.88¢ respective for each of the aforementioned eight quarters. All quarterly and semi-annual dividends on the issued and outstanding preferred shares of the Company have been paid aggregating $6.7 million in 1992, and $7.8 million in 1991.

Item 5: ANALYSIS OF FINANCIAL POSITION AND RESULTS OF OPERATIONS
(Management's Discussion and Analysis)

1) Capital Resources and Liquidity

Capital Expenditures

The Progress property acquisition and the asset rationalization program carried out by the Company during 1992 were consistent with its stated strategies to aggressively pursue acquisition opportunities and to dispose of non-core properties. In addition to oil and gas exploration and development activities and the Shell acquisition, the contribution of equity to the Syracuse cogeneration project marked a significant use of funds during the year. The capital expenditures for 1992 and 1991 are summarized in the following table.

	1992	1991
	($ millions)	
Proven property acquisitions	76.9	2.6
Non-core property dispositions	(18.7)	(0.8)
Finding and onstream costs	39.5	72.2
Other	8.1	9.8
Total property plant and equipment	105.8	83.8
Equity investments in cogeneration projects	21.2	(0.2)
	127.0	83.6

The $75 million expenditure to acquire Shell's interest in the Progress area consisted of a 28 percent working interest in the 77 mmcfd Progress gas plant, 109.9 bcf of proven natural gas reserves, 4.5 mmbbls of proven crude oil and NGLs reserves and 20,000 net acres of undeveloped land. Work done on the Progress property in late 1992 and early 1993 resulted in an increase in natural gas production from 19 mmcfd to 25 mmcfd and crude oil and NGLs from 880 bpd to 1100 bpd.

During 1992, the Company disposed of 34 non-core properties which tend to have higher operating costs and no longer fit the Company's exploration and operation focus. The sale proceeds of $18.7 million will be reinvested for the acquisition and exploration of longer life, higher quality reserves in core areas.

Capital expenditures incurred for exploration and development activities declined during 1992 as the Company focused on the acquisition of proven reserves versus exploration. A total of $22.7 million was spent on exploration and development drilling which resulted in the addition of 13.8 bcf of natural gas and 0.8 mmbbls of crude oil and NGLs to the Company's proven reserve base. The balance of the finding and onstream costs were incurred for expenditures that did not add reserves directly to the Company's proven reserve base including $5.0 million for the workover of a deep sour gas well located in the Thunder Creek area of British Columbia and $3.2 million for development drilling in the Hatton area of Saskatchewan to maintain deliverability. Finding and onstream costs, calculated on a per unit basis, amounted to $1.81 per mcfe as indicated in the table below. The following table of reserve acquisition costs on a per mcfe basis (10 mcf = 1 bbl) for 1992 and the five years ended 1992 has been computed on the basis of proven reserve additions only. These additions have been adjusted for any revisions applicable to the original booked reserves.

	1992		Five Year Total 1988 – 1992	
	Costs ($ millions)	$/mcfe	Costs ($ millions)	$/mcfe
Exploratory drilling	12.2	0.56	79.1	0.24
Development drilling and workovers	10.5	0.48	57.5	0.18
Land acquisition and retention costs	6.1	0.28	64.0	0.20
Seismic	3.2	0.15	31.4	0.09
Onstream costs	7.5	0.34	109.7	0.34
Total finding and onstream	39.5	1.81	341.7	1.05
Proven property acquisitions	76.9	0.48	254.0 (1)	0.50
Total	116.4	0.64	595.7	0.71

(1) Includes the Progress, Coseka and Brenda acquisitions.

NCO negotiated a major exploration farm-in agreement with PanCanadian Petroleum Limited during 1992 for a large block of freehold land located in southern Alberta. The agreement provides NCO with access to 128,000 acres of undeveloped land over a three year period in an area where the Company has been successful over the past ten years. NCO will conduct an extensive seismic program and drill a minimum of four exploratory wells for an initial capital commitment of $1.6 million.

Investments in cogeneration activities during 1992 related primarily to an equity infusion into the Syracuse project. The initial commitment, which was made in 1991, required funding of up to U.S.$27 million for an 83 percent equity ownership in the project. On December 24, 1992, the Company reduced its proposed equity holding to an initial 33 percent interest by contributing U.S.$14.5 million and bringing in an additional equity partner who contributed U.S.$12.5 million to the project. The initial ownership interest is subject to change over time dependent upon the annual cash flow and cumulative after tax rate-of-return of the project.

The financing of the Company's capital expenditures for 1992 and 1991 are summarized in the following table.

	1992	1991
	($ millions)	
Cash flow from operations	96.6	89.3
Liquidation of investment portfolio	25.6	–
Preferred share dividends	(6.7)	(7.8)
Common share dividends	(7.3)	(7.3)
Deferred revenue repayments	(8.6)	(8.1)
Syracuse prepaid gas contract	–	42.2
Increase (decrease) in long term debt	27.4	(24.7)
Total	127.0	83.6

Polaris Mine Royalty Interest

NCO has a 25 percent royalty interest in the Polaris zinc and lead mine located on Little Cornwallis Island in the Canadian Arctic. During 1992, the Company reached an agreement with Cominco Ltd., the operator of the Mine, which deemed that the Mine had reached payout status during 1992. The Company is currently entitled to receive its full 25 percent royalty revenue from the Mine as opposed to the five percent being received prior to payout. Cash flow from the Mine will be utilized for oil and gas activities.

An evaluation of the reserves of the Polaris Mine at January 1, 1993, was prepared by Strathcona Mineral Services Limited, independent engineering consultants of Toronto, Ontario. This evaluation indicated 10.6 million tonnes of proven and probable reserves of ore expected to be mined and milled over the next 11 to 12 years. According to this report, the average grade of the ore body anticipated to be recovered over this period of time is approximately 13 percent zinc and 3.5 percent lead. The grade and production of the Polaris ore body is anticipated to be relatively consistent over the reserve life.

Investments

The purpose of the Company's investments is to hold securities and other financial instruments which may be used to fund future investments in the oil and gas business as they arise while maintaining a financially strong balance sheet. At December 31, 1992, the Company's investment portfolio consisted of the preferred and common shares listed as follows and having a book value of $94.9 million and a $65 million principal amount note receivable from a major Canadian corporation with which the Company deals at arm's length.

The portfolio is managed with the objective of investing in securities that primarily provide tax free dividends. Through this arrangement, NCO has earned dividends at an average rate-of-return of approximately one-half of the Canadian bank prime rate plus two and one half percent.

The investment portfolio has fluctuated in size over the past several years as a result of the investment of funds arising from an equity issue in 1990 and sales from the investment portfolio to fund capital requirements. (See Item 3 "Investment Activities" of this document.)

At December 31, 1992, the portfolio consisted of the following preferred and common shares.

Security	Number of Shares	1992 Carrying Cost	1991 Carrying Cost
		($ millions)	
Publicly Listed Securities			
Brascade Resources Inc. Series B, Convertible Preferred Shares (2)(3)	1,019,997	40.8	40.8
Trilon Financial Corporation, Class 1 Series A, Preferred Shares (2)	495,000	4.6	7.2
Varitech Investors Corporation Floating Rate Retractable Preferred Shares (2)	300,000	7.5	–
Norcen Energy Resources Limited First Preferred Series B, Auction Shares (2)	18	18.0	–
Gulf Canada Resources Limited Senior Preferred Shares, Series 1	5,450,000	–	25.1
Royal Trustco Limited Series K Preferred (2).	9	–	4.5
Unicorp Canada Corporation Class II Series B Preferred	1,500,000	–	17.9
		70.9	95.5
Other			
Mico Investments Limited Common Shares (1)(2)	960,000 (4)	24.0	25.0
Total securities		94.9	120.5
Note receivable from American Express Canada Ltd.	–	65.0	65.0
Total investments		159.9	185.5

(1) These shares are in a private company, the shares of which are not listed for trading on a stock exchange.
(2) A related party to NCO.
(3) Shares which can be retracted at managements option, which management intends to hold to retraction are valued at the higher of market value or the retraction value.
(4) 1991 – 1,000,000 common shares.

NCO sold $43.1 million to, and purchased $38.0 million in marketable securities from, related parties during 1992. The Company carries investments at the lower of cost or net realizable values.

Capitalization

One of NCO's key financial strategies is to maintain a strong balance sheet which is evidenced by the Company's debt to equity ratio, free cash flow to debt coverage, investments and unutilized credit facilities. This strong financial position has provided NCO with the stability to continue its exploration and development activities, and also to pursue acquisition opportunities at a time when the economic environment for senior oil and gas producers remains difficult. The increase in long term debt during 1992 reflected the additional financing requirements of the Company for the Progress acquisition and the Syracuse equity investment. NCO's capitalization for the years ended December 31, 1992 and 1991, are summarized in the following table.

	1992 ($ millions)	%	1991 ($ millions)	%
Common share equity	609.8	63	609.3	64
Preferred share equity	101.3	11	102.3	11
Deferred liabilities	48.0	5	53.7	6
Long term debt	202.2	21	177.8	19
	961.3	100	943.1	100
Book value per common shares outstanding ($/common share)		16.67		16.68

Long Term Debt

In an effort to reduce its overall cost of debt and to provide maximum flexibility in managing its debt, the Company took several steps to improve the manner in which it financed its business activities during 1992. A commercial paper program was launched early in 1992 to sell short term promissory notes in order to gain access to more favourable cost of funds. The program was authorized for up to $150 million and received an investment grade rating of R-1 (low) from a recognized bond rating agency. Early in 1992, the Company retired $65 million of its 10 percent debentures held by a major chartered bank by utilizing funds from a new revolving unsecured term credit facility negotiated with the same bank. The remaining $5.1 million of the 10 percent debentures were repaid at the same time utilizing other existing credit facilities.

In order to meet its growing operating and capital requirements during 1992, NCO negotiated an additional $25 million to its unsecured term credit facility and $25 million to is annual revolving loan facilities. During the year, a major debt rating firm increased the rating of the long term debt and preferred shares of NCO. Dominion Bond Rating Service assigned an "A" rating to the Company's long term unsecured debt, and Pfd-2 and Pfd-2 (low) ratings to the Class A and Class B Preferred Shares of the Company respectively. At December 31, 1992, the Company had $124.6 million in unutilized credit facilities.

Shareholders' Equity

There were no significant changes to the permanent equity capital base of the Company during 1992. The Company repurchased 42,300 Class B Preferred Shares, Series 6, shares during the year for a total cost of $1.0 million (1991 – 39,300 for $0.8 million) pursuant to the terms of the repurchase obligation of three quarters of one percent per quarter. NCO had a Normal Course Issuer Bid outstanding which expired on February 19, 1993. While no shares were repurchased under this Bid during 1992, the Company will undertake to reestablish such a Bid procedure in the future if it represents a prudent use of its resources.

Liquidity

NCO believes it has a satisfactory liquidity position as a result of its working capital position, its ability to raise funds through realization of its investments, currently unutilized credit facilities of $124.6 million, and its general policy to fund exploration and development opportunities from internally generated cash flow.

2) Results of Operations

Consolidated

NCO increased revenues and cash flow from operations during 1992 however, a large increase in non-cash expenses resulted in a decline in net earnings. Total revenues, net of royalties, rose by 14 percent to $375.7 million in 1992 from $328.8 million in 1991 due primarily to an increase in the sale of third party natural gas and higher royalty revenues on the Polaris Mine. Cash generated from operations totalled $96.6 million or $2.46 per common share in 1992, an eight percent increase over the 1991 total of $89.3 million or $2.23 per common share. Net earnings decreased by 35 percent in 1992 to $11.0 million as compared to $16.9 million in 1991 due to higher depletion rates resulting from the downward revision to proven reserves in 1991 combined with a provision for impairment in the carrying costs of the FPB cogeneration project. Net earnings attributable to common shares, after the deduction of preferred share dividends, were $4.3 million or $0.12 per common share, and $9.1 million or $0.25 per common share in 1992 and 1991 respectively. The 1992 decline in earnings, due to the downward reserve revision, was anticipated by the Company and reported in its 1991 annual report.

The following is a discussion and analysis of the Company's operating and financial activities for 1992 as compared to 1991.

i) Oil and Gas and Related Activities

The results of oil and gas and related operations for 1992 and 1991 are summarized in the following table.

	1992	1991
	($ millions)	
Natural gas revenues	113.4	120.9
Natural gas royalties	(15.1)	(21.6)
Natural gas operating costs	(31.7)	(30.9)
Oil and NGLs revenues	42.8	42.9
Oil and NGLs royalties	(6.2)	(7.0)
Oil and NGLs operating costs	(10.7)	(11.2)
Net sulphur revenues	0.3	1.1
Net upstream operations	92.8	94.2
Royalty tax credit	1.8	1.5
Marketing costs	(2.4)	(2.7)
Net pipeline transmission revenues	2.1	2.0
Net drilling revenues	0.1	0.1
Net oil and gas and related operations	94.4	95.1

The variance in natural gas revenues for 1992 versus 1991 resulted primarily from lower product pricing. A decline in royalty rates, stemming from higher gas cost allowance deductions in Alberta and lower royalty rates in Saskatchewan, resulted in the favorable variance to natural gas royalties.

Natural gas production averaged 237 mmcfd in 1992 compared to 234 mmcfd in 1991 while production of crude oil and NGLs declined from 6,549 bpd in 1991 to 6,128 bpd in 1992. Production gains from new finds and the Progress acquisition were offset by declining deliverability from maturing fields, pipeline curtailments, and the effects of disposition of non-core producing properties.

NCO's average natural gas price declined to $1.31 per mcf in 1992 from $1.41 per mcf in 1991 due to the ongoing oversupply situation in western Canada resulting from constrained pipeline export capability. Although natural gas spot prices rose to over $3.00 per mcf in late 1992, the overall impact of the higher prices on the Company's average price was minimal since a large portion of corporate production was sold to fixed price direct markets. System gas prices also did not fully reflect the higher spot prices late in 1992 due to the pooling method employed by WGML and PAG and because SaskEnergy contracts have fixed pricing until November 1993. NCO's average crude oil and NGLs price rose to $19.07 per bbl in 1992 from $17.94 per bbl in 1991 as a consequence of the narrowing of differentials between light and medium grade crudes and the weakening of the Canadian dollar.

ii) Marketing Activities

The results of marketing operations for 1992 and 1991 are summarized in the following table.

	1992	1991
	($ millions)	
Revenues	197.7	159.0
Operating expenses	(190.5)	(154.4)
Net margin	7.2	4.6

Revenues from marketing operations rose by 24 percent in 1992 as compared to 1991 due to an increase in the sale of third party natural gas from 249 mmcfd in 1991 to 336 mmcfd in 1992. The major gains in sales were to the California, mid-western, and southeastern U.S. markets. The increase in cost of sales was also due to higher sales volumes, however, the net margin increased from $4.6 million in 1991 to $7.2 million in 1992. The higher margin was earned primarily during the first six months of 1992 due to a significant differential between sales prices in the mid-west U.S. and supply costs in Alberta. The Company was able to take advantage of the unusual market differentials because of the firm service it holds on the Northern Border Pipeline system. Revenues derived from the sale of NCO's natural gas production by its marketing group are recorded as part of the Company's natural gas revenues.

The first half gain in the marketing margin was partially offset by losses incurred on sales to eastern Canada and the mid-west U.S. during November and December 1992. The losses arose due to unmatched sales contracts which required the Company to purchase natural gas at unusually high spot prices in order to fulfil its sales commitments. The rising prices experienced late in the year were primarily a function of severe cold weather, compounded by transportation outages and lower than anticipated industry deliverability. Natural gas spot prices have subsequently declined which has reduced the remaining exposure of the Company. Mitigation efforts are ongoing and include the utilization of excess corporate volumes which are expected to be made available as take levels by traditional aggregators decline, contract price, term and/or volume renegotiating as well as the optimization of third party supply volumes between U.S. markets to eastern Canadian markets.

The Company, in compliance with accounting regulations, accrued $2.7 million in the 1992 year end results for expected losses in January and February 1993 resulting from the unmatched sales contracts. Losses after February 1993, if any, are subject to the current volatility of the marketplace and are difficult to estimate. The Company had approximately 55 mmcfd of unmatched natural gas sales at the beginning of February 1993, for the period ending October 31, 1993. (See also Note 15 to the Consolidated Financial Statements).

Several new long term natural gas contracts were finalized by the Company during 1992, including a 15 year, 16 mmcfd sales agreement with an unrelated cogeneration facility located in upper New York state. The contract represents the second of three projects being developed in New York by the same unrelated development group. NCO finalized a 15 year, 12 mmcfd contract for the first project in 1991 and holds a 15 year, 16 mmcfd contract for the third project which is currently in the process of being financed. Approximately 65 percent, or 30 mmcfd of the natural gas required for the three contracts, will be satisfied through third party supply.

During 1992, the Company also negotiated a long term gas supply contract for its two Florida cogeneration projects. The Company signed an agreement with ARCO GAS, a major U.S. energy company, to supply up to 31 mmcfd of the total 43 mmcfd of fuel required by the two projects. As NCO holds the long term supply contracts for both cogeneration projects, it has been able to secure an adequate margin for the next 15 years.

iii) Cogeneration Activities

The results of cogeneration operations for 1992 and 1991 are summarized in the following table.

	1992	1991
	($ millions)	
Revenues	14.0	3.7
Equity losses in projects	(1.3)	(0.6)
Operating expenses	(11.7)	(2.6)
Operating income	1.0	0.5
Provision for impairment and capitalized costs written-off	(2.8)	–
Net (loss) earnings	(1.8)	0.5

Operating income from cogeneration operations increased 100 percent in 1992 as compared to 1991 due primarily to the construction management fees earned on the two Florida projects. The increase in revenues and operating costs are related to the development fees earned, and the costs incurred, in connection with the closing of financing for the Lake and Pasco cogeneration projects.

The $2.8 million provision for impairment reflects a $2.2 million reduction in the book carrying cost of the FPB project in which the Company has a 30 percent co-general partnership interest but is not the operator. The project has sufficient cash resources at this time to service its non-recourse debt however, future projections indicate the project will be unable to meet its financing commitments by 1994. Work is currently underway to restructure the project for the benefit of all parties. Management believes that the current book carrying value of $1 million for FPB is a realistic expectation of potential future recoveries from the project.

During 1992, NCO completed three important cogeneration financing agreements. In January 1992, non-recourse financing for the Pasco cogeneration project was arranged. The Company holds a 50 percent equity interest in the project and must make an equity contribution of U.S.$5.4 million in mid-1993 upon completion of construction. In July 1992, the Company's Syracuse project commenced commercial operations and later in the year, the project's construction loan was converted to a term facility. NCO will now receive its share of the cash flow generated by the Syracuse project. In August 1992, the Company completed arrangements for construction financing of the Lake project. As part of these arrangements, the construction lender agreed to purchase and lease back the facility to NCO at the completion of construction in mid-1993.

Polaris Mine Royalty Income

NCO recognized $10.6 million in royalty revenues from the Polaris Mine in 1992 due to the payout recovery of the accumulated development costs on the Mine as compared to $3.3 million in 1991. NCO will now receive its full 25 percent royalty related to the Mine's net operating revenues as opposed to five percent as was the case prior to payout. Payout occurred despite declining zinc prices during the last quarter of 1992 because the Company reached agreement with the operator of the Mine regarding the realization of tax pools within the payout account. The full payout settlement of $7.9 million was reflected in 1992.

Investment and Other Income and Interest Expenses

Investment and other income declined from $19.4 million in 1991 to $13.2 million in 1992 due to a reduced investment portfolio balance and lower average prime interest rates in Canada. Investment and other income is generated primarily from dividends earned on the investments as well as interest earned on a $65 million note receivable. Returns for both investments are based on Canadian bank prime lending rates which averaged 7.6 percent during 1992 as opposed to 10.1 percent during 1991. Approximately $25 million of the investment portfolio was liquidated without loss in 1992 to partially finance the Progress acquisition.

While the reduction in lending rates during 1992 had a negative impact on investment and other income, it had a positive effect on the Company's overall cost of borrowing. Interest expenses declined to $12.9 million in 1992 compared to $17.3 million in 1991 due to lower interest rates, savings achieved through the Company's commercial paper program and the favourable terms of the Company's major credit facilities negotiated in mid-1991. Debt levels during 1992 averaged $182.9 million as compared to $189.3 million in 1991 while the Company's average cost of borrowing was 6.6 percent in 1992 versus 9.1 percent in 1991.

Administrative Expenses

General and administrative expenses for 1992 and 1991 are summarized in the following table.

	1992	1991
	($ millions)	
Total general and administrative costs	22.6	23.4
Restructuring costs	(0.5)	(0.8)
Employee Gain Sharing Plan	(2.0)	–
Normalized total general and administrative costs	20.1	22.6
Operator recoveries	(6.1)	(8.7)
Normalized general and administrative costs	14.0	13.9
Normalized general and administrative costs on an mcfe of production basis (10 mcf = 1bbl)	0.128	0.126

Normalized general and administrative expenses for 1992 were in line with 1991 expenses however, normalized total expenses were below 1991 levels as a result of rationalization efforts which commenced at the beginning of 1992. The savings were offset by the reduced operator recoveries which in turn was primarily the result of the reduced exploration and development spending program in 1992 and the sale of non-core producing properties.

In 1991, the Company implemented an Employee Gain Sharing Plan under which all employees are entitled to variable cash compensation contingent upon NCO earning an economic after tax return of at least eight percent. Compensation levels increase from that point up to a corporate economic return of 15 percent or greater under certain circumstances. Compensation for each employee is based upon their level of responsibility and the fulfillment of predetermined performance criteria. The Company has made a provision of $2.0 million in the 1992 accounts with respect to this plan.

Depreciation, Depletion and Amortization ("DD&A")

NCO recorded DD&A of $80.1 million in 1992, a significant increase over the $64.5 million recorded in 1991. The increase consisted of $0.1 million related to higher production volumes, $13.2 million related to a higher per unit of production depletion rate, $2.8 million related to the write-down of certain cogeneration assets partially offset by a favorable variance of $0.5 million related to corporate and other assets.

The average per unit of production depletion rate was $0.73 per mcfe in 1992 as compared to $0.60 per mcfe in 1991 however, the 1992 average rate of $0.73 per mcfe was comparable to the December 31, 1991 rate of $0.70 per mcfe. At year end 1991, the Company recorded a downward revision to proven reserves as a result of both constant and escalated price evaluations performed by internal engineers. The negative impact of this write-down on a full year of production led to the increase in DD&A charges during 1992. At December 31, 1992, the Company's per unit of production depletion rate was $0.78 per mcfe which was in part a result of the constant price case downward reserve revision of 47.9 bcf recorded by Sproule and the Company engineers at year end 1992.

Income Taxes

Income taxes, as a percentage of pretax income, were 35 percent for 1992 which was relatively consistent with the 1991 percentage. Income tax expenses were $3.6 million lower during 1992 than in 1991 as a result of the lower operating revenues.

NCO's current and planned capital expenditures program, together with the carry forward of unused eligible tax deductions from expenditures in earlier periods, continues to provide sufficient shelter against taxable income for the Company and its subsidiaries. At December 31, 1992, the consolidated tax pool balances available to offset future taxable income totalled $466 million. The approximate weighted average rate at which they can be used in the immediate future is 25 percent. NCO paid cash taxes of $1.7 million in 1992 (1991 – $1.3 million) relating to Large Corporations Tax.

Reference is made in Note 12 to the Consolidated Financial Statements on the United States and Canadian principal accounting policy differences and their effect on the results of operations for the years ended December 31, 1992 and 1991.

Future Outlook

i) Industry

The Canadian oil and gas industry has suffered through a protracted downturn over the past several years. Depressed product prices, in the face of rising costs, have continued to place pressure on cost management and have resulted in significant downsizing of staff and the reorganization of the industry as a whole. During its five year planning period, NCO anticipates that the economy will go through a slow recovery period until the end of 1994, with inflation remaining at its current low level, and interest rates remaining near their present levels.

The Company expects that costs associated with environmental issues, and regional and municipal taxes, will increase faster than the rate of inflation over the short term and provincial governments will exercise a greater degree of flexibility in the modification of royalty regimes to coincide with the changing economic circumstances of the industry.

The marketing of natural gas is expected to change in nature as supply and demand become more balanced. Gas-to-gas competition will be reduced and, overtime, natural gas will compete more directly with other energy sources on an equivalent unit of energy basis. The Company anticipates that natural gas prices will increase moderately over the near term while the protracted recession will cause crude oil prices to remain at their current levels in the near term.

The demand for independent power production and cogeneration is expected to be strong over the next ten years as new electrical capability is required to meet increasing demand and to replace aging capacity. It is expected that independent power producers will continue to provide a significant portion of the new demand given the ability for these producers to bring new capacity on line at a discount to the avoided cost of utilities. Natural gas is expected to be a fuel of choice for future power cogeneration facilities as a result of increasing environmental pressures.

ii) North Canadian Oils Limited

The most significant current uncertainty in the corporate future of North Canadian Oils Limited is the outcome of the proposed merger with Norcen Energy Resources Limited. Comments made in this report are predicated on the assumption that the Company will continue in its present capacity as a publicly traded company.

The following table indicates the sensitivity of NCO to certain changing variables based on the assumptions used in preparation of the Company's 1993 budget.

	Cash Flow	Net Earnings
	($/common share)	
$1.00 change in average crude oil pricing	0.05	0.02
$0.10 change in average natural gas pricing	0.15	0.09
1,000 bpd change in crude oil and NGLs production	0.14	0.06
10 mmcfd change in natural gas production	0.09	0.01
$0.01/mcf change in natural gas marketing margin	0.05	0.04

As NCO moves forward into 1993, the most significant challenge the Company faces is the reduction of its depletion rate through finding or acquiring low cost reserves. The Company plans to allocate a minimum of $17 million of its projected $58 million capital expenditures budget to the acquisition of proven properties which are complementary to NCO's exploration and development focus areas, with an emphasis on natural gas to support NCO's marketing and cogeneration initiatives. Future acquisition strategies will depend on the availability of desirable reserves, the economics of acquiring versus exploration and the ongoing success of the Company's divestiture program which partially fund acquisitions. The success of NCO's 1992 divestment program has greatly reduced the number of properties available for disposition however, the Company expects additional funds of $8 million from the divestment of non-core properties in 1993. These funds will also be reinvested with the budgeted $17 million in the acquisition of proven properties. Funds from dispositions are expected to continue to decline in subsequent years.

Exploration efforts are expected to continue to be concentrated in the core focus areas to build on the successful wells drilled by the Company in early 1993. This strategy will involve step-out drilling on lands surrounding 1992 reserve finds. Drilling on other high grade, multi-zone prospects in the west central Alberta area will also be undertaken in the near future.

The Company also plans to expand its activities in other focus areas through seismic and drilling programs. Drilling is planned on lands acquired in the PanCanadian farm-in in 1992. In 1993, the Company plans to continue evaluating existing seismic data on the undeveloped properties acquired as part of the Progress acquisition. This is expected to lead to second quarter drilling. Finally, the Company is planning to carry out a seismic program on larger reserve prospects in northern Alberta.

The objectives of the marketing group centre on actively managing the sales portfolio for corporate natural gas to maximize the value of NCO's reserves. NCO believes that the growth of the marketing operations is contingent upon any future growth in NCO's corporate deliverability and cogeneration business. The synergies created by the Company's forward integration provides NCO the ability to market natural gas over and above its corporate requirements.

The Company expects power cogeneration activities will continue to play an important role in the maximization of the value of its natural gas reserves. New cogeneration projects must provide the Company with an adequate rate-of-return on the equity invested as well as long term contracts for natural gas supply. New projects will continue to be financed on a substantially non-recourse basis and the Company will only take on risks which it feels are manageable. While no commitments were made in 1992, several promising opportunities are currently under evaluation in Canada and the United States. Included in the 1993 capital expenditure budget is U.S.$5.4 million representing the equity contribution requirements for the Company's Pasco cogeneration project.

NCO expects it will continue to have one of the lowest administrative expenses (expressed on an equivalent mcf of production basis of 10 mcf = 1 bbl) within the Canadian oil and gas industry. The Company will continue to operate with the fewest number of people possible however, this will not be done to the extent of sacrificing efficiency. In addition to controlling administrative costs, the Company will also continue to manage its debt and foreign currency risk matters in a manner which is keeping with NCO's risk adverse management policy. The Company will take advantage of any opportunities to secure low cost long term financing or to lessen its exposure to the U.S. dollar without incurring undue risk. NCO currently has sufficient tax pools to shelter it from cash taxation in the near term.

During 1993 and onward, the Company will continue to pursue its strategy of examining all its assets to ensure that they earn a minimum after tax rate-of-return between 10 to 15 percent over their life. In absence of that, NCO will dispose of such assets at opportune times.

Finally, the continuous improvement initiative undertaken by the Company in 1992 has resulted in production gains and operating cost savings of $2.3 million to NCO and its oil and gas joint venture partners. A further $6.0 million of potential savings have been identified and the feasibility of these ideas is currently being examined. This program will continue to play an important part in the management of the Company.

The Company believes the Canadian oil and gas industry has reached the bottom of the current low cycle. NCO believes it is well positioned because of its integrated exploration, production, marketing and cogeneration approach to take advantage of an upturn in the industry. This is expected to be accomplished through its strategic transportation portfolio, its marketing expertise, cogeneration initiative and the operational efficiencies of the oil and gas operations created both through the divestment of non-core assets and the continuous improvement program. Over the near term the Company expects cash flows and earnings to rise moderately through to 1994.

Item 6: MARKET FOR THE SECURITIES OF THE COMPANY

The common shares of the Company are listed on the Toronto Stock Exchange, Montreal Exchange and American Stock Exchange.

Item 7: SUBSIDIARIES OF THE COMPANY

Name of Subsidiary	Percentage of Ownership of Voting Shares	Organized Under the Laws of
North Canadian Investments Ltd.	100.0	Ontario, Canada
North Canadian Marketing Corporation	100.0	California, U.S.A.
North Canadian Marketing Inc.	100.0	Alberta, Canada
North Canadian Power Incorporated	100.0	California, U.S.A.
North Canadian Resources, Inc.	100.0	Delaware, U.S.A.
Coseka Resources Limited	100.0	Canada
NCO Acquisition Limited	100.0	Canada
NCO Mines Limited	100.0	Alberta, Canada
North Canadian Oil & Gas Incorporated	100.0	Texas, U.S.A.
Ada Power Company	100.0	California, U.S.A.
NCP Syracuse, Inc.	100.0	Delaware, U.S.A.
NCP Lake Power Incorporated	100.0	Delaware, U.S.A.
NCP Dade Power Incorporated	100.0	Delaware, U.S.A.
Syracuse Investment Inc.	100.0	Delaware, U.S.A.
NCP Pasco Incorporated	100.0	Delaware, U.S.A.
NCP Gem Incorporated	100.0	Delaware, U.S.A.

Item 8: DIRECTORS AND OFFICERS

The number of directors of the Company is fixed at ten. The Board currently consists of nine directors. The following table sets forth certain information with respect to the directors of NCO. As at January 31, 1993, the directors and officers of the Company as a group, beneficially owned directly or indirectly or exercised control or discretion over 5.1 percent of the common shares of the Company.

Name and Residence	Principal Occupation for the Past Five Years and Positions with the Company or Significant Affiliate	Year First Elected as a Director	Age
Norman R. Gish (2) Calgary, Alberta	President and Chief Executive Officer of the Company since prior to 1988.	1986	57
Paul J. Hill (1,4) Regina, Saskatchewan	President of McCallum Hill Limited (a real estate, insurance, broadcasting, oil and gas company) since prior to 1988.	1987	47
Marshall A. Jacobs (3,4) New York, New York	Of counsel to the law firm of Jacobs Persinger & Parker since January 1992; prior thereto Senior Partner of that firm since prior to 1988.	1963	73
H. Earl Joudrie (1,4) Toronto, Ontario	Chairman of the Board of Algoma Steel Inc. (an iron and steel producer) since July 1991; Chairman since February 1990 and Chief Executive Officer from February 1990 to July 1991 of American Eagle Petroleums Ltd. (an oil and gas exploration and development company) and Chairman of Rayrock Yellowknife Resources Inc. (a mineral development company) since September 1988; prior thereto President and Chief Executive Officer from April 1985 to September 1988 of Encor Energy Corporation Inc. (an oil and gas exploration and development company).	1992	58
James F. Kay (3) Toronto, Ontario	Chairman of the Board of CME Capital Inc. (a holding company) since September 1988; prior thereto Chairman of the Board of Dylex Limited (a clothing manufacturer and retail company) since prior to 1988.	1977	71
David W. Kerr (2) Toronto, Ontario	Toronto, Ontario President since prior to 1988 and Chief Executive Officer since July, 1990 of Noranda Inc. (a natural resources company).	1982	49
Paul M. Marshall (2) Toronto, Ontario	Toronto, Ontario Vice Chairman of the Board of Brascan Limited (a natural resources, consumer products and financial services company) since prior to 1988.	1987	69
Alfred Powis (2) Toronto, Ontario	Chairman of the Board of Noranda Inc. (a natural resources company) since prior to 1988.	1988	62
Alan R. Thomas (1,3) Toronto, Ontario	Senior Vice-President, Finance, and Chief Financial Officer of Noranda Inc., (a natural resources company) since prior to 1988.	1988	50

(1) Member of the Audit Committee
(2) Member of the Executive Committee
(3) Member of the Stock Option Committee
(4) Member of the Special Committee (Independent Committee)

The directors will serve until the next annual meeting of the Company or until their successors are elected or appointed.

Officers

The municipality of residence of all the Company's officers is Calgary, Alberta. The names, the offices held by them in the Company, and their principal occupations within the last five years are as follows:

Name and Municipality of Residence	Office of the Company held and Principal Occupations for the Past Five Years	Age
Norman R. Gish	President and Chief Executive Officer since prior to 1988.	57
G. Barry Padley	Senior Vice-President, Chief Financial Officer and Corporate Secretary since July 1991; prior thereto Senior Vice-President, Finance and Administration.	51
Donald D. McKechnie	President of the Company's subsidiary, North Canadian Power ("NCP") and Vice-President of the Company since December 1992; prior thereto Vice-President, Finance and Controller of the Company since January 1992, Vice-President of the Company and NCP since August 1990, and Vice-President, Finance and Treasurer of the Company since prior to 1988.	42
D. Garry Ramsden-Wood	Senior Vice-President, Marketing since May 1991; from December 1988 to January 1991 President of Northridge International (Canada) Ltd; prior thereto General Manager, Marketing, of Dome Petroleum Ltd.	48
Gerald F. Stevenson	Senior Vice-President, Engineering and Production since June 1991; prior thereto Vice-President, Production of Suncor Inc. since September 1990, Vice-President, Reserve Development and Engineering Services since February 1990, Director of Business Development since February 1989, and Manager of Business Development of Suncor Inc. since prior to 1988.	48
John H. Williams	Senior Vice-President, Exploration and Land since November 1991; prior thereto Vice-President Exploration.	57
Edward J. Flanagan	Vice-President, Employee Services since May 1990; prior thereto Manager, Human Resources and Administration.	43
David C. Jacobus	Vice-President, Land since prior to 1988.	39
Naser A. Khan	Treasurer since August 1990; prior thereto Manager, Financial Accounting.	35
Theresia R. Reisch	Assistant Corporate Secretary since November 1992; prior thereto Corporate Secretary of Canadian Foremost Ltd. since 1990 and of Argus Resources Ltd. since prior to 1988.	43

The officers hold office at the pleasure of the Board of Directors of the Company.

Item 9: ADDITIONAL INFORMATION

Additional information including executive compensation and indebtedness, principal holders of the Company's securities, options to purchase securities and the interest of insiders in material transactions, where applicable, is contained in the Company's definitive Management Proxy-Circular for the most recent Annual General Meeting of Shareholders. Also, additional financial information is provided in the Company's comparative audited Consolidated Financial Statements for the year ended December 31, 1992, a copy of which is attached hereto.

Item 10: FINANCIAL STATEMENTS

The following are the comparative Consolidated Financial Statements for the year ended December 31, 1992 and 1991, and the Auditors' Report thereon.

MANAGEMENT REPORT

The accompanying Consolidated Financial Statements and all information in the annual report are the responsibility of management. The Consolidated Financial Statements have been prepared by management in accordance with the accounting policies in the notes to the Consolidated Financial Statements. Where necessary, management has made informed judgments and estimates in accounting for transactions which were not complete at the balance sheet date. In the opinion of management, the Consolidated Financial Statement have been prepared within acceptable limits of materiality and are in accordance with Canadian generally accepted accounting principles appropriate in the circumstances. The financial information elsewhere in the annual report has been reviewed to ensure consistency with that in the Consolidated Financial Statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized, assets are safeguarded from loss or unauthorized use and financial records properly maintained to provide reliable information for the preparation of Consolidated Financial Statements.

Deloitte & Touche, an independent firm of Chartered Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent annual general meeting, to examine the Consolidated Financial Statements in accordance with the generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented below.

The Board of Directors is responsible for ensuring that management fulfils its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee of the Board. This committee, which is comprised of directors who are not employees of the Corporation, meets with management and the external auditors twice a year to satisfy itself that management's responsibilities are properly discharged and to review the Consolidated Financial Statements before they are presented to the Board of Directors for approval. The Consolidated Financial Statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

NORMAN R. GISH
President and Chief Executive Officer

G. BARRY PADLEY
Senior Vice-President
Chief Financial Officer and
Corporate Secretary

REPORT OF INDEPENDENT CHARTERED ACCOUNTANTS

The Shareholders
North Canadian Oils Limited

We have audited the Consolidated Balance Sheets of North Canadian Oils Limited as at December 31, 1992 and 1991 and the Consolidated Statements of Earnings, Retained Earnings and Cash Flows each of the two years in the period ended December 31, 1992. These Consolidated Financial Statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these Consolidated Financial Statements based on our audits.

We have conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the Consolidated Financial Statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the Consolidated Financial Statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall Consolidated Financial Statement presentation.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 1992 and 1991 and the results of its operations and the changes in its cash flows for each of the two years in the period ended December 31, 1992 in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche

Calgary, Canada
February 10, 1993

DELOITTE & TOUCHE
Chartered Accountants

COMMENTS BY AUDITOR FOR U.S. READERS ON CANADA– U.S. REPORTING CONFLICT

In the United States, reporting standards for auditors require the addition of an explanatory paragraph following the opinion paragraph when there are changes in accounting principles that have a material effect on the comparability of a company's financial statements, such as the change described in Note 2 of the financial statements. Our report to the shareholders dated February 10, 1993 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

Deloitte & Touche

Calgary, Canada
February 10, 1993

DELOITTE & TOUCHE
Chartered Accountants

NORTH CANADIAN OILS LIMITED

CONSOLIDATED BALANCE SHEETS

(millions of Canadian dollars)

Assets	December 31 1992	December 31 1991
Current assets		
Investments (Note 3)	$ –	$ 120.5
Accounts receivable	99.8	75.7
	99.8	196.2
Investments (Note 3)	159.9	65.0
Property and equipment ("Full cost" Notes 1 and 4)	789.0	757.2
Mining royalty interest	54.7	55.7
Investments in power cogeneration facilities (Note 5)	36.6	18.9
Other assets, at cost	8.5	8.9
	$ 1,148.5	$ 1,101.9
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable	$ 89.9	$ 66.7
Current portion of deferred liabilities (Note 6)	8.6	7.6
	98.5	74.3
Deferred liabilities (Note 6)	48.0	53.7
Long term debt (Note 7)	202.2	177.8
Deferred income taxes (Note 8)	88.7	84.5
Shareholders' equity		
Share capital (Note 9)		
Preferred	101.3	102.3
Common 36,574,006 shares (1991 – 36,534,379)	468.1	464.6
Retained earnings	141.7	144.7
	711.1	711.6
	$ 1,148.5	$ 1,101.9

On behalf of the Board:

Director

Paul J. Hill

Director

NORTH CANADIAN OILS LIMITED

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars)

	Years Ended December 31 1992	1991
Revenues		
Operating, net of royalties (Note 11)	$ 351.9	$ 306.1
Mining royalty	10.6	3.3
Investment and other	13.2	19.4
	375.7	328.8
Expenses		
Operating (Note 11)	249.3	205.9
Administrative	16.5	14.7
Interest on long term debt	12.9	17.3
Depreciation, depletion and amortization	80.1	64.5
	358.8	302.4
Earnings before taxes	16.9	26.4
Income taxes (Note 8)	5.9	9.5
Net earnings	11.0	16.9
Dividends on preferred shares	6.7	7.8
Net earnings attributed to common shares	$ 4.3	$ 9.1
Net earnings per common share (Note 1)	$ 0.12	$ 0.25

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(millions of Canadian dollars)

	Years Ended December 31 1992	1991
Balance, beginning of year	$ 144.7	$ 142.9
Net earnings	11.0	16.9
	155.7	159.8
Deduct		
Dividends on preferred shares	6.7	7.8
Dividends on common shares	7.3	7.3
Balance, end of year	$ 141.7	$ 144.7

NORTH CANADIAN OILS LIMITED
CONSOLIDATED STATEMENTS OF CASH FLOWS
(millions of Canadian dollars)

	Years Ended December 31 1992	1991
Operating activities		
Net earnings	$ 11.0	$ 16.9
Non-cash items:		
Depreciation, depletion and amortization	80.1	64.5
Deferred income taxes (Note 8)	4.2	8.2
Other	1.3	(0.3)
Cash generated from operations	96.6	89.3
Change in current accounts (Note 13)	0.1	(27.6)
Cash generated from operating activities	96.7	61.7
Financing activities		
Net increase in long term debt	24.4	5.4
Issue of common shares	3.5	2.6
Redemption of preferred shares	(1.0)	(0.8)
Dividends paid on preferred shares	(6.7)	(7.8)
Dividends paid on common shares	(7.3)	(7.3)
(Decrease) increase in deferred liabilities	(8.6)	34.1
Repurchase of common shares	–	(3.3)
Cash generated from financing activities	4.3	22.9
Total cash generated	$ 101.0	$ 84.6
Investing activities		
Expenditures for property and equipment, net	$(105.8)	$ (83.8)
Power cogeneration investments	(21.2)	0.2
Decrease (increase) in investments	25.6	(0.4)
Other	0.4	(0.6)
Cash utilized in investing activities	$(101.0)	$ (84.6)

1. Summary of Significant Accounting Policies

These Consolidated Financial Statements of North Canadian Oils Limited ("the Company") are stated in Canadian dollars and have been prepared in accordance with accounting principles generally accepted in Canada which are in accordance with generally accepted accounting principles in the United States, except as set out in Note 12.

Operations of the Company

The Company is engaged principally in the oil and gas exploration, development and production business, but also operates two other important and complementary businesses, namely the marketing of corporate and third party natural gas and the direct investment in and supply of natural gas to power cogeneration facilities.

Principles of Consolidation

The Consolidated Financial Statements include those of the Company and its wholly-owned subsidiaries. Long term investments in power cogeneration projects in which the Company does not own more than 50.0 percent and does not exercise operating, financing and investing control are accounted for on an equity basis. The difference between the costs of investments in power cogeneration projects and the underlying net book value of the assets are amortized over the life of the related assets.

Oil and Gas Operations

Substantially all of the Company's oil and gas activities are carried out jointly with others and these financial statements reflect only the Company's proportionate interest in such operations.

The Company follows the full cost method of accounting for oil and gas properties and related expenditures, whereby all costs related to the exploration for and development of oil and gas reserves are capitalized in country by country cost centres. Such costs include those related to lease acquisitions, geological and geophysical activities, lease rentals on non-producing properties and drilling of productive and non-productive wells. Proceeds from disposal of properties are normally deducted from the full cost pool without recognition of gain or loss.

Depletion of oil and gas properties and depreciation of production equipment and facilities, net of salvage values, are calculated using the unit-of-production method based upon estimated proven reserves, before royalties, converted to a common unit of measure using relative energy content of six thousand cubic feet of natural gas equalling one barrel of crude oil.

Costs subject to depletion under the full cost method also include estimated future site restoration costs. These would include the cost of production equipment removal and environmental clean-up based upon regulations and economic circumstances at year end. The annual provision for future restoration costs is included in depreciation, depletion and amortization expenses while the cumulative amount, net of costs incurred, is included in deferred liabilities. The Company does not include unproven and unevaluated properties in costs subject to depletion until such time as it is determined whether proven reserves are attributable to the properties or impairment has occurred.

The Company applies a ceiling test to capitalized costs on a quarterly and annual basis to ensure that such costs do not exceed estimated future net revenues from production of proven reserves at year end market prices adjusted for future fixed contract prices, less future administrative, financing, site restoration, abandonment and income tax costs.

Mining Royalty Interest

The Company holds a 25 percent royalty interest in the total net proceeds of production from a lead and zinc mine located on Little Cornwallis Island in the Canadian Arctic. Prior to 1992, royalty revenue was contingent upon the recovery of production and development costs of the Mine. As at December 31, 1992, all development costs had been recovered (1991 – $32.5 million outstanding).

The cost relating to the royalty interest is amortized on the unit-of-production method based upon the estimated gross proven reserves. On an annual basis the Company evaluates the net realizable value of the year end reserves of the Mine to ensure that costs capitalized do not exceed the future net royalty revenues based upon year end prices.

Power Cogeneration Facilities

The Company capitalizes costs related to the development and construction of power cogeneration facilities on a project by project basis after a letter of intent has been signed. Development costs consist primarily of overhead charges incurred to the point of financing while construction costs include interest and overhead during the construction phase in addition to normal capital costs. Capitalized development costs are applied against development fees received at the point of financing with any excess fees included in income. Development costs of unsuccessful projects previously capitalized are written-off as determined. Capitalized construction costs and net capitalized development costs are amortized over the useful life of each project beginning at commercial start-up.

Investments

The Company holds a portfolio of investments for ultimate utilization in the oil and gas business. These investments are composed of private and publicly listed securities and are stated in the Consolidated Financial Statements at the lower of cost and net realizable value.

Income Taxes

The Company follows the tax allocation method of accounting under which the income tax provision is based on the earnings reported in the accounts. Under this method, the Company provides for deferred income taxes to the extent that income taxes otherwise payable are eliminated by claiming capital cost allowance and exploration and development costs in excess of the depreciation, depletion and amortization provisions recorded in the accounts. Investment tax credits are deducted from the related expenditures when the benefit is realized.

Foreign Currency Translation

The Company translates the foreign denominated monetary assets and liabilities of integrated foreign operations at the exchange rate prevailing at the year end and revenues and expenses (other than depreciation, depletion and amortization) at average rates of exchange during the year. Exchange gains and losses arising on the translation of the accounts are included in consolidated earnings unless related to long term items, in which case they are deferred and recognized over the life of the related item. Non-monetary assets and liabilities are translated at historical rates of exchange.

The Company uses balance sheet assets denominated in United States dollars to hedge its United States dollar denominated obligations.

Net Earnings Per Common Share

Net earnings per common share are computed by dividing net earnings attributable to common shares by the weighted average number of common shares outstanding (1992–36,558,990; 1991–36,474,172). Fully dilutive net earnings per common share for both years were inapplicable as none of the convertible issues were dilutive.

2. Change in Accounting Policy

During 1991 the Company changed, on a retroactive basis, its full cost accounting policy to exclude costs related to unevaluated properties from costs subject to depletion until such time as it is determined whether proven reserves are attributable to the properties or impairment has occurred. The effect of this accounting policy change was to increase property and equipment, deferred income taxes and retained earnings at December 31, 1990, by $17.8 million, $10.1 million and $7.7 million respectively. As a result of a reduction in depreciation and amortization, net earnings for the year ended December 31, 1991, were increased by $2.6 million.

3. Investments

	1992	1991
	($ millions)	
Publicly listed	70.9	95.5
Other	24.0	25.0
	94.9	120.5
Note receivable	65.0	65.0
	159.9	185.5
Classified as short term	–	(120.5)
Investments	159.9	65.0

At December 31, 1992, the Company reclassified its investments from short term to long term.

The note receivable from a non-related major corporation bears interest at the Canadian bank prime lending rate, is secured by a pledge of certain marketable securities, and is due not later than January 9, 1995.

From time to time, the Company arranges investment transactions in conjunction with certain affiliates. These transactions are arranged without cost and at normal market terms. At December 31, 1992, investments included holdings in affiliates in the amount of $94.9 million (1991 – $77.5 million). Dividends from such investments totalled $6.3 million during 1992 (1991 – $6.0 million).

Publicly listed securities are after valuation allowances of $6.6 million (1991 – $4.0 million) and include, at December 31, 1992, $18.0 million (1991 – Nil) of market auction Preferred Shares.

During 1992, the Company purchased a total of $38.0 million from, and sold a total of $43.1 million of portfolio investments to, certain affiliated companies.

4. Property and Equipment

	1992			1991		
	Gross Costs	Accumulated Depreciation	Net Costs	Gross Costs	Accumulated Depreciation	Net Costs
			($ millions)			
Oil and gas properties, equipment and related drilling and pipeline assets	1,121.0	360.7	760.3	1,021.7	290.1	731.6
Marketing development costs	12.9	1.9	11.0	11.1	1.4	9.7
Other	26.3	8.6	17.7	22.7	6.8	15.9
Total	1,160.2	371.2	789.0	1,055.5	298.3	757.2

The Company does not include unproven and unevaluated properties in costs subject to depletion until it is determined whether proven reserves are attributable to the properties or impairment has occurred. At December 31, 1992, such costs totalled $49.8 million (1991 – $60.0 million).

5. Investments in Power Cogeneration Projects

The Company's investment in power cogeneration projects is as follows.

	1992	1991
	($ millions)	
Project Orange Associates, L.P. ("Syracuse")	21.2	–
Ada Cogeneration Limited Partnership ("Ada")	13.9	14.4
Federal Paper Board Limited Partnership ("FPB")	1.0	4.2
Other	0.5	0.3
	36.6	18.9

The Company currently holds equity investments in three operational cogeneration projects located in Syracuse, New York; Ada, Michigan; and Commerce, California. The equity holding in the Syracuse, New York, project consists of an initial 33 percent interest comprised of a one percent general partnership and a 32 percent limited partnership interest in Syracuse. This ownership is subject to change depending upon the partnership achieving specified annual cash flow levels and after tax rates-of-return. The interest in the Ada, Michigan, project consists of a 50 percent economic interest including a one percent general partnership interest in Ada and a performance based leasehold interest in the site lease. The Company's interest in the Commerce, California, project consists of a 30 percent co-general partnership interest in FPB. All of the projects are financed through non-recourse debt.

The summarized combined financial information for the three projects (1991 – two) in which the Company owns an equity investment is represented by the following gross assets and liabilities as at December 31, 1992 and 1991, as well as the gross results of operations for the years then ended.

Combined Balance Sheets

	1992	1991
	($ millions)	
Cogeneration project assets	335.4	64.6
Current assets	13.6	21.5
Total assets	349.0	86.1
Term debt	273.9	52.5
Other liabilities	11.5	6.5
Partners' equity	63.6	27.1
Total liabilities and partners' equity	349.0	86.1

Combined Statements of Earnings (Loss)

	1992	1991
	($ millions)	
Revenues	25.9	23.4
Expenses	(30.5)	(25.5)
Earnings (Loss)	(4.6)	(2.1)

During 1992, the Company entered into agreements to manage and participate in the ownership of, and the natural gas supply to, a power cogeneration facility located in Dade City, Florida (the Pasco Project). The Company's 50 percent equity commitment of U.S.$ 5.4 million is due upon completion of construction which is expected in mid-1993. The Consolidated Financial Statements do not reflect this investment nor the related liability. (See also Note 15.)

Also during 1992, the Company entered into an interim construction financing and sale and leaseback arrangement for its 100 percent owned power cogeneration facility located in Umatilla, Florida (the Lake Project). During the construction phase of the project, financing will be provided by the eventual purchaser of the asset. The sale and leaseback transaction is to take place at the completion of construction which is expected in mid-1993. The Consolidated Financial Statements do not reflect the assets under construction of U.S. $72.3 million nor the related non-recourse long term debt of U.S.$65.7 million.

6. Deferred Liabilities

	1992			1991		
	Total Obligation	Current Portion	Long term Portion	Total Obligation	Current Portion	Long term Portion
	($ millions)					
Prepaid gas contract	40.9	2.4	38.5	42.2	2.0	40.2
Take-or-pay contracts	8.0	4.9	3.1	13.0	4.3	8.7
Deferred sale of future economic benefits	3.9	1.3	2.6	5.2	1.3	3.9
Future restoration costs	3.8	–	3.8	0.9	–	0.9
	56.6	8.6	48.0	61.3	7.6	53.7

Pursuant to take-or-pay provisions included in certain natural gas sales contracts, payments were received by the Company in respect of annual contract natural gas volumes not taken by the purchaser. In November 1984, the purchaser began to take delivery of the natural gas and the Company has recognized revenue related to the natural gas taken. The purchaser's present delivery schedule for the natural gas will allow recognition of $4.9 million and $3.1 million of revenue in 1993 and 1994 respectively.

During 1991, the Company received a prepayment of $42.2 million for 50 bcf of natural gas to be delivered to the Syracuse power cogeneration project over a 16 to 20 year period commencing in 1992. Revenue will be recognized over the term of the contract as natural gas is delivered.

In 1990, the Company received $6.4 million for the transfer to the new equity partner in the Ada project of NCO's future economic benefits for the period 1991 through 1995. The remaining $3.9 million of deferred revenues at December 31, 1992, will be amortized over the remaining three year period.

Future restoration costs are composed of the cumulative provision for future restoration costs less actual costs incurred in this regard.

7. Long Term Debt

	1992	1991
	($ millions)	
Revolving term bank loans – Cdn. Funds	126.4	73.2
– U.S. Funds ($63.4 million; 1991-$30.0 million)	75.8	34.5
10 percent debentures	–	70.1
	202.2	177.8

The revolving term bank loans are unsecured and committed as a minimum to July 14, 1998, under a Term Credit Facility. Canadian denominated revolving loans bear interest at the Floating Bankers' Acceptance Rate plus five eighths percent while the U.S. denominated revolving loans bear interest at the London Interbank Offering Rate plus one half percent. All loans are repayable at the maturity of the Term Credit Facility which at the earliest would be in 1998.

During 1992, the Company repaid all the 10 percent debentures outstanding utilizing the funds from a newly arranged $65 million Unsecured Revolving Term Facility with a major Canadian chartered bank and through its existing credit facilities.

The Company has credit facilities with various financial institutions totalling $334.1 million of which $240.0 million is committed for a minimum of six years and the remaining is on demand and renewable on an annual basis. At December 31, 1992, $209.5 million had been drawn on these facilities including $7.3 million for various Letters of Credit which are used mainly to secure transportation contracts.

8. Income Taxes

The provisions for income taxes differs from the result which would be obtained by applying the combined Canadian federal and provincial tax rate of 43.8 percent (1991 – 43.8 percent) to earnings before taxes . The difference results from the following.

	1992	1991
	($ millions)	
Computed "expected" income tax	7.4	11.6
Increase (decrease) in income taxes resulting from:		
Non-deductible crown payments	7.8	9.4
Effect of subsidiaries and consolidation	3.2	3.1
Federal resource allowance	(9.1)	(9.6)
Non-taxable dividends	(3.5)	(4.1)
Provincial credits	(0.8)	(0.6)
Other	(0.8)	(1.6)
Deferred income taxes	4.2	8.2
Large corporations capital tax	1.7	1.3
	5.9	9.5

Deferred income taxes arose from the deduction of capital cost allowance, exploration and development expenditures and lease acquisition costs permitted for tax purposes in excess of depreciation, depletion and amortization for accounting purposes.

9. Share Capital

Authorized

Unlimited Special non-voting shares each without nominal or par value
Unlimited Common Shares each without nominal or par value
Unlimited Class A and Class B Preferred Shares issuable in series

Issued

Preferred Shares

	1992		1991	
	Shares (000's)	Amount ($ millions)	Shares (000's)	Amount ($ millions)
Class A, Series 1	2,000	50.0	2,000	50.0
Class B, Series 6	1,222	30.6	1,264	31.6
Class B, Series 7	828	20.7	828	20.7
		101.3		102.3

Class A Preferred

The Class A Preferred Shares, Series 1, rank senior to the Class B Preferred Shares, Series 6 and 7, with respect to all rights, privileges, restrictions and other conditions attaching to the preferred shares and holders of these shares are entitled to cumulative dividends at the rate of 70 percent of the floating bank prime rate per share. These shares are redeemable by the Company, under certain conditions.

Class B Preferred

The Class B Preferred Shares, Series 6 and 7, earn cumulative dividends at the annual rate of 8 percent and 7.5 percent respectively, and are redeemable solely at the option of the Company. Pursuant to a quarterly repurchase obligation of three quarters of one percent of the Class B Preferred Shares, Series 6, outstanding at December 31, 1990, the Company repurchased 42,300 (1991 – 39,300) shares in the open market during 1992 at a total cost of $1.0 million (1991 – $0.8 million).

Common Shares Issued and Reserved

	1992		1991	
	Shares (000's)	Amount ($ millions)	Shares (000's)	Amount ($ millions)
Outstanding, beginning of year	36,534	469.8	36,596	471.7
Under Management Share Purchase Plan	31	0.2	64	0.8
Under Employee Incentive Share Option Plan	9	0.1	103	1.2
Miscellaneous repurchase cancellation and other	–	–	(229)	(3.9)
	36,574	470.1	36,534	469.8
Less: notes receivable (Note 10)	–	2.0	–	5.2
Outstanding, end of year	36,574	468.1	36,534	464.6

Under a Normal Course Issuer Bid which expired on December 14, 1991, the Company repurchased and cancelled 229,200 common shares for a total consideration of $3.3 million during 1991. A subsequent Normal Course Issuer Bid was issued on February 21, 1992, with expiry on February 19, 1993. No shares were repurchased under this Bid during 1992.

At December 31, 1992, the Company had reserved for issue a total of 2,903,720 common shares under the Share Purchase Plan, the Employee Incentive Share Option Plan and the Employee Savings Plan.

10. Other Information

Share Purchase Plan

The Company has a Management Share Purchase Plan whereby common shares may be purchased by the President and CEO (prior to 1992 all senior management) of the Company. During 1992, 30,450 (1991 – 64,100) common shares were purchased under this Plan. Notes receivable with respect to the shares purchased under this Plan in the amount of $2.0 million at December 31, 1992 (1991 – $4.9 million) are due from certain officers and are shown as a reduction from common share capital. At December 31, 1992, 31,288 common shares had been reserved for issuance under this Plan.

Employee Incentive Share Option Plan

	1992	1991
Shares under option, beginning year	2,220,235	1,428,960
Granted	449,085	3,426,610
Exercised	(9,177)	(103,829)
Cancelled	(459,134)	(2,531,506)
Shares under option, end of year	2,201,009	2,220,235

The Company has a Employee Incentive Share Option Plan whereby options are granted to all employees at the market price on the date granted and are exercisable, cumulatively as to 20 percent annually, on the anniversary date of their issue. Options granted are exercisable at prices ranging from $8.88 to $18.88 per share and expire at various dates between 1993 and 1997. Notes receivable in respect of the shares purchased under this plan in the amount of $Nil at December 31, 1992 (1991 – $0.3 million) are due from certain officers of the Company and are shown as a reduction from common share capital. At December 31, 1992, 2,672,432 shares had been reserved for issuance under the Company's Employee Incentive Share Option Plan.

Employee Savings Plan

Effective January 1, 1988, the Company introduced an Employee Savings Plan for all employees. Under the Savings Plan, employees can contribute up to six percent of their annual salary which is matched by the Company. The Company's portion vests immediately and is invested in the Company's common shares. During 1992, the Company's contribution under this Plan totalled $1.1 million (1991 – $1.1 million). At December 31, 1992, 200,000 common shares had been reserved for issuance under this Plan.

Pension Plan

The Company has a defined contribution Pension Plan, available on a voluntary basis to all employees, whereby employees' contributions are matched by an equivalent contribution by the Company. Up to and including December 31, 1992, the Company matched up to four percent of base salary and effective January 1, 1993, the Company will match up to six percent of base salary. Company contributions made under the Plan totalled $0.7 million in 1992 (1991 – $0.7 million).

Related Party Transactions

The Company incurred professional fees aggregating $1.3 million for the year ended December 31, 1992 (1991 – $1.0 million) to two legal firms which certain directors of the Company were partners or counsel.

11. Business and Geographic Segments

a) Industry Segments

Management has determined that the following represent the major business segments of the Company.

i) upstream oil and gas exploration and production operations including related pipeline transmission and drilling operations;
ii) marketing of corporate and third party natural gas and;
iii) development, operation and equity ownership of natural gas-fired cogeneration electrical/steam facilities.

	Year Ended December 31, 1992				
	Oil & Gas	Marketing	Cogeneration ($ millions)	Corporate	Total
Gross revenue, net of royalties	141.5	197.7	14.0	–	353.2
Equity losses	–	–	(1.3)	–	(1.3)
	141.5	197.7	12.7	–	351.9
Operating expenses	(47.1)	(190.5)	(11.7)	–	(249.3)
Depreciation, depletion and amortization	(74.0)	(0.5)	(2.8) (1)	(2.8)	(80.1)
Net segment earnings	20.4	6.7	(1.8)	(2.8)	22.5
Mining royalty					10.6
Investment and other					13.2
Administrative					(16.5)
Interest on long term debt					(12.9)
Income taxes					(5.9)
Net earnings					11.0

(1) $2.2 million relates to a writedown of the Company's equity investment in the Federal Paper Board project.

	Year Ended December 31, 1991				
	Oil & Gas	Marketing	Cogeneration ($ millions)	Corporate	Total
Gross revenue, net of royalties	144.0	159.0	3.7	–	306.7
Equity losses	–	–	(0.6)	–	(0.6)
	144.0	159.0	3.1	–	306.1
Operating expenses	(48.9)	(154.4)	(2.6)	–	(205.9)
Depreciation, depletion and amortization	(60.8)	(0.6)	–	(3.1)	(64.5)
Net segment earnings	34.3	4.0	0.5	(3.1)	35.7
Mining royalty					3.3
Investment and other					19.4
Administrative					(14.7)
Interest on long term debt					(17.3)
Income taxes					(9.5)
Net earnings					16.9

	Assets Employed As at December 31		Capital Expenditures Year Ended December 31	
	1992	1991	1992	1991
	($ millions)			
Oil and gas	791.0	760.4	99.8	77.4
Marketing	62.1	50.0	1.8	1.2
Cogeneration	39.4	25.2	0.4	1.0
Mining royalty interest	54.7	55.7	–	–
Investments	159.9	185.5	–	–
Corporate	41.4	25.1	3.8	4.2
	1,148.5	1,101.9	105.8	83.8

b) Geographic Segments

	Years Ended December 31	
	1992	1991
	($ millions)	
Total revenues, net of royalties		
Canadian -Domestic	170.7	180.0
- Export	46.7	32.6
United States	134.5	93.5
	351.9	306.1
Mining royalty	10.6	3.3
Investment and other	13.2	19.4
	375.7	328.8

	Segment Earnings Year Ended December 31		Assets Employed As at December 31	
	1992	1991	1992	1991
	($ millions)			
Canada	22.5	32.8	1,052.3	1,032.9
United States	–	2.9	96.2	69.0
	22.5	35.7	1,148.5	1,101.9

12. Reconciliation to Accounting Principles Generally Accepted in the United States

These financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in Canada. Under United States ("U.S.") accounting principles, the calculation of the ceiling test under the full cost method requires the discounting of future net revenues from production of proven oil and gas reserves by 10 percent. Also, deductions from net revenue for administrative and financing costs under the calculation are not permitted. Under the U.S. ceiling test, the Company would have recorded a write-down of its oil and gas assets in the amount of $75.0 million as at December 31, 1991, and $26.0 million in 1986.

The revision of the original terms of the conversion in 1986 of the 8 percent debenture under Financial Accounting Standard No. 84 would have required an increase in common share capital of $26.4 million and a corresponding decrease in earnings and retained earnings for that year.

Under U.S. GAAP the Company is required to treat all classes of preferred shares with mandatory redemption options as part of long term debt. The Company's Class B Preferred Shares, Series 6, have repurchase obligations on the open market of up to three percent of the outstanding stock under certain conditions commencing January 1, 1991.

Financial Accounting Standard No. 60 requires the Company to record in current earnings all unrealized foreign exchange translation losses associated with long term debt that is not hedged. Under Canadian accounting principles, the Company is only required to record losses related to the current year and then defer the remaining losses for recognition over the life of the debt.

U.S. GAAP requires the effect of accounting policy changes to be recorded in the results of the year in which it occurs as opposed to retroactive adoption as required under Canadian GAAP. (See also Note 2)

Under Financial Accounting Standard No. 12 the reclassification of investments from short term to long term must be done at the lower of cost or market at the date of transfer.

The effect of the above on the consolidated financial statements for the years ended December 31 would have been as follows.

Consolidated Statements of Earnings

	1992	1991
	($ millions except per share data)	
Net earnings in accordance with Cdn. GAAP	11.0	16.9
Adjustments:		
Ceiling test write-down	–	(75.0)
Depletion expense arising from the write-down in 1986 and 1991	8.2	1.4
Foreign exchange	(1.5)	–
Investment reclassification	(3.0)	–
Accounting policy change	–	7.7
Net earnings (loss) in accordance with U.S. GAAP	14.7	(49.0)
Net earnings (loss) per common share basic and fully diluted	0.22	(1.56)

Consolidated Balance Sheets

	1992	1991
	($ millions)	
Net book value of property and equipment	703.2	663.1
Investments	156.9	65.0
Long term debt	234.2	209.4
Preferred share capital	70.7	70.7
Common share capital	494.5	490.9
Retained earnings	24.9	24.2

Under the terms of implementation of Financial Accounting Standards No. 109 ("FASB 109"), the Company is required to assess the impact of this pronouncement on its 1992 Consolidated Financial Statements. Under FASB 109 the Company is required to reflect the difference between the net book value of its assets and their related tax basis at the tax rates enacted at December 31, 1992. Prior accounting requirements were based on an income statement approach and used the historical tax rates to build up the deferred tax balances. The Company's best estimate of the impact of this change in 1992 would be to increase the deferred tax payable balance on the balance sheet by $30 million. The Company will account for this change on a prospective basis in 1993.

13. Changes in Other Current Accounts

	1992	1991
	($ millions)	
Current assets – (increase) decrease		
Accounts receivable	(24.1)	44.3
Current liabilities – increase (decrease)		
Accounts payable	23.2	(7.7)
Current portion of deferred liabilities	1.0	3.3
Current portion of long term debt	–	(67.5)
	24.2	(71.9)
Net change in other current accounts	0.1	(27.6)

The reclassification of investments from current to long term at the end of 1992 is not reflected above.

14. Quarterly Financial Information
(Unaudited)

	Three Months Ended			
	Dec 31	Sept 30	June 30	March 31
	($ millions except share amounts)			
1992				
Total revenues, net of royalties	120.2	89.2	88.3	78.0
Net earnings *	0.4	4.6	4.1	1.9
Net earnings per common share** after preferred share dividends-Basic	(0.03)	0.08	0.06	0.01
1991				
Total revenue, net of royalties	83.9	75.0	80.3	89.6
Net earnings	4.4	3.0	2.8	6.7
Net earnings per common share** after preferred share dividends-Basic	0.07	0.03	0.02	0.13

* The fourth quarter reflects a one time write-down provision of $2.2 million on the FBP cogeneration project, and a $2.7 million provision for estimated marketing losses to be incurred in 1993.

** Fully diluted net earnings per common share for all the quarters were inapplicable as none of the convertible instruments were dilutive.

15. Commitments and Contingencies

The Company's minimum payments on operating leases at December 31, 1992 are as follows

	($ millions)
1993	1.6
1994	1.8
1995	1.9
1996	1.8
1997	1.9
Thereafter	9.2
	18.2

In conjunction with the sale and leaseback arrangement reached to provide the necessary financing for NCO's power cogeneration project located in Umatilla, Florida, the Company has entered into a 16 year operating lease with subsequent renewal terms. The final payment terms of the lease will be determined at date of the sale and leaseback and will be dependent upon the future net cash flow estimates for the project at that date.

As part of its equity participation in the Pasco cogeneration project, the Company is obligated to contribute U.S.$5.4 million at the completion of construction of the project which is expected in mid-1993. As part of the sale and leaseback arrangement related to the Lake cogeneration project, the Company may be required to invest up to U.S.$15 million under certain conditions. At this time, management does not anticipate it will be required to make any equity contribution under this guarantee.

The Company, as part of its overall marketing and natural gas strategy matches a certain portion of short term committed sales contracts with uncommitted supply contracts ("unmatched sales"). At December 31, 1992, the unmatched sales amounted to approximately 55 mmcfd resulting in 1993 realized losses of approximately $2.7 million to February 10, 1993. The Company provided for this loss in its 1992 results. As of February 10, 1993, the management of the Company is unable to estimate any future losses that may occur beyond this date due to the uncertainty and volatility of the market for spot natural gas. Management continues its efforts to mitigate this imbalance. It is the opinion of management that this unmatched sales situation will not have a material negative impact on the 1993 results of operations.

The Company, as part of its natural gas marketing activities, has certain obligations and commitments connected with the holding of firm transportation space on various pipelines in North America. In addition, the Company has guaranteed certain financial and risk items related to its equity ownership in cogeneration projects. This has exposed the Company to certain contingent liabilities which are not ordinarily given in the process of negotiating non-recourse financing for projects. At this time, management does not believe that these contingent liabilities will result in financial loss to the Company.

16. Disclosure of Oil and Gas Producing Activities as Required by Statement of Financial Accounting Standards No. 69

Costs incurred in oil and gas property acquisitions and exploration and development activities for the years ended December 31.

	1992	1991
	($ millions)	
Acquisition of proven properties, net of divestitures	58.2	1.8
Exploration	20.7	31.8
Development	18.0	25.1
Acquisition of unproven properties	2.7	15.3

Results of operations for producing activities for the years ended December 31.

	1992	1991
	($ millions)	
Sales (net of royalties)	137.0	137.8
Production costs	(42.4)	(42.1)
Depreciation and depletion	(73.6)	(60.3)
Income before taxes	21.0	35.4
Income taxes	(12.0)	(17.5)
Results of operations from producing activities (excluding corporate overhead and interest costs)	9.0	17.9

Estimated quantities of proven crude oil and NGLs and natural gas reserves as at December 31.

(Unaudited)	1992		1991	
	Crude Oil & NGLs	Natural Gas	Crude Oil & NGLs	Natural Gas
Beginning of year	14.2	991.0	16.2	1,214.5
Revisions of previous estimates	0.1	(47.9)	(0.8)	(189.0)
Purchase of minerals-in-place	4.8	110.8	0.1	6.0
Sale of minerals-in-place	(1.8)	(42.5)	-	(2.0)
Extensions and discoveries	0.8	13.8	1.1	47.0
Production	(2.2)	(86.9)	(2.4)	(85.5)
End of year	15.9	938.3	14.2	991.0

(i) Crude oil and NGLs are stated in mmbbls before royalty interests and natural gas is stated in bcf before royalty interests.

(ii) The year end quantities are based on the reports of an external consultant for core properties and in house engineering reports for non-core properties. Core properties constitute approximately 84 percent of total reserves.

(iii) At December 31, 1992, 222.1 (1991 – 86.7) bcf of natural gas and 1.4 (1991 – 0.7) mmbbls of crude oil and NGLs of the total proved reserves are undeveloped.

(iv) There are no long term supply agreements with foreign governments or any significant foreign geographic reserves.

(v) The year end reserve data includes 100 percent of the reserves of all subsidiaries. Revisions are the result of the re-evaluations of the quantities and recoverabilities of reserves based on studies of existing reserves.

(vi) At December 31, 1992, the Company's proven sulphur reserves were 0.7 (1991 – 0.6) million metric tonnes.

(vii) Crude oil and NGLs reserves include 5.2 mmbbls of NGLs.

(viii) Reserve quantities were determined using constant year end prices (adjusted for future fixed contract prices) and costs.

Standardized measure of discounted net cash flows and change therein relating to proven crude oil and NGLs and natural gas reserves at December 31.

(Unaudited)	1992	1991
	($ millions)	
Future cash inflows	1,807.8	1,570.8
Future production costs	(512.5)	(531.3)
Future development costs	(135.9)	(112.0)
Future income tax expenses	(231.1)	(153.1)
Future net cash flows (1)	928.3	774.4
10 percent annual discount for estimated timing of cash flows	(344.9)	(297.4)
Standardized measure of discounted net cash flows	583.4	477.0

(1) Future net cash flows are after deducting royalties and are computed using year end prices (adjusted for future fixed contract prices), costs and year end statutory income tax rates.

The following are the principal sources of change in the standardized measure of discounted future net cash flows.

(Unaudited)	1992	1991
	($ millions)	
Sales and transfers of oil and gas produced, net of production cost	(94.6)	(95.7)
Net changes in prices and production costs	198.6	111.7
Purchase of minerals-in-place	173.4	12.1
Sales of minerals-in-place	(66.1)	(3.1)
Extensions, discoveries and improved recovery, less related costs	23.7	102.8
Development costs incurred during the period	18.0	(0.6)
Net change in development costs	(41.9)	(39.3)
Revisions of previous quantity estimates	(52.1)	(314.7)
Accretion of discount	47.7	52.0
Net changes in income taxes	(90.0)	188.1
Other	(10.3)	(56.6)
	106.4	(43.3)

Amortization per equivalent physical unit of production ($/mcf).

	1992	1991
Depreciation and depletion	0.73	0.60

17. Comparative Figures

Certain of the comparative amounts have been reclassified to conform with current presentation.

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