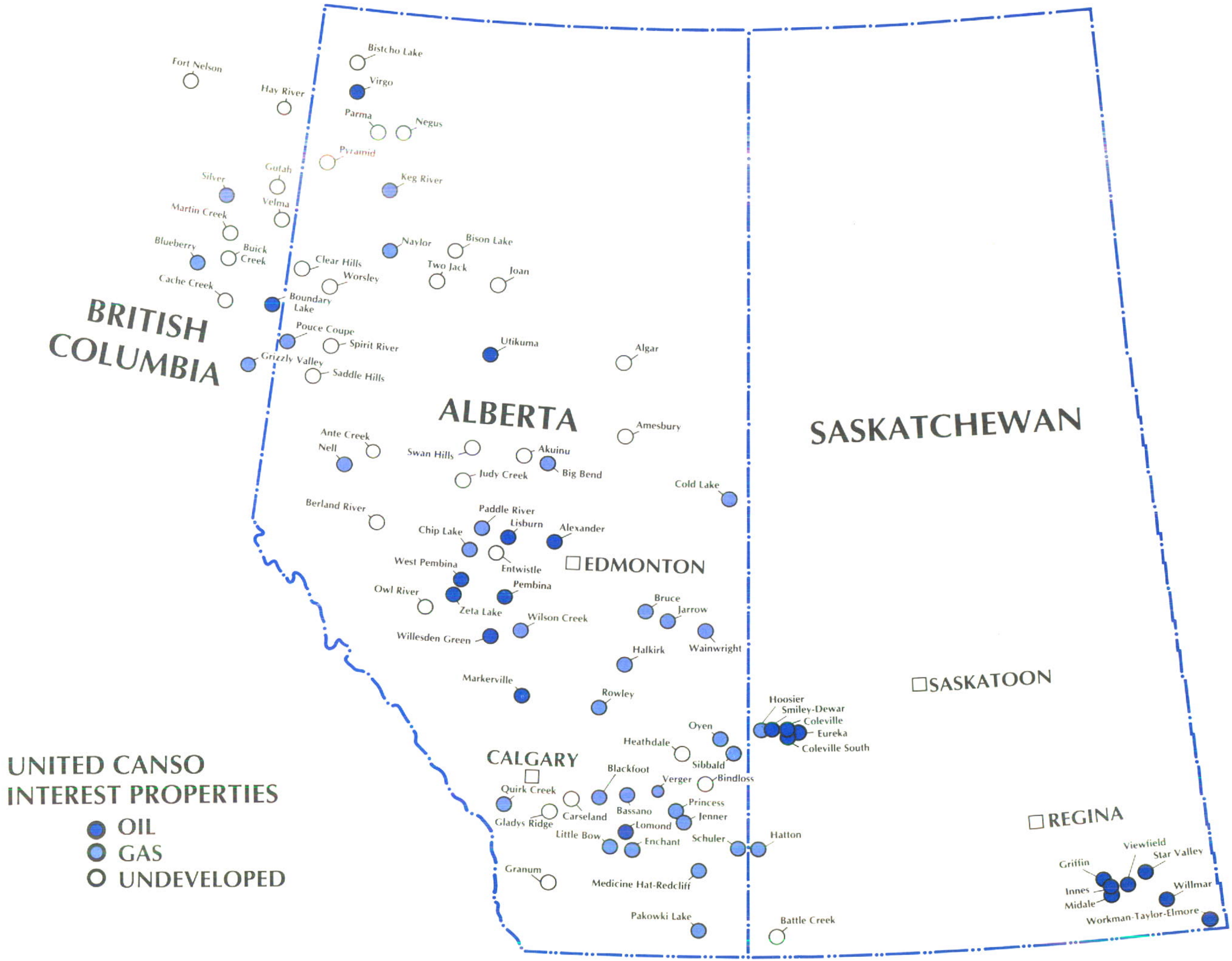
C

1984
ANNUAL
REPORT

UNITED
Canso
OIL & GAS LTD.



UNITED CANSO
INTEREST PROPERTIES
OIL
GAS
UNDEVELOPED
BRITISH COLUMBIA
ALBERTA
SASKATCHEWAN
EDMONTON
CALGARY
SASKATOON
REGINA
Fort Nelson
Hay River
Bistcho Lake
Virgo
Parma
Negus
Pyramid
Gutah
Silver
Keg River
Velma
Martin Creek
Blueberry
Buick Creek
Naylor
Bison Lake
Clear Hills
Worsley
Two Jack
Joan
Cache Creek
Boundary Lake
Pouce Coupe
Spirit River
Grizzly Valley
Saddle Hills
Utikuma
Algar
Amesbury
Ante Creek
Nell
Swan Hills
Akuinu
Big Bend
Judy Creek
Cold Lake
Berland River
Paddle River
Lisburn
Alexander
Chip Lake
Entwistle
West Pembina
Pembina
Owl River
Zeta Lake
Wilson Creek
Willesden Green
Bruce
Jarrow
Wainwright
Halkirk
Markerville
Rowley
Hoosier
Smiley-Dewar
Coleville
Eureka
Coleville South
Oyen
Heathdale
Sibbald
Bindloss
Blackfoot
Verger
Quirk Creek
Carseland
Bassano
Princess
Jenner
Gladys Ridge
Lomond
Little Bow
Enchant
Schuler
Hatton
Granum
Medicine Hat-Redcliff
Pakowki Lake
Battle Creek
Griffin
Viewfield
Star Valley
Innes
Midale
Willmar
Workman-Taylor-Elmore

Contents

Copies of the annual report in Form 10-K filed with the Securities and Exchange Commission will be forwarded without charge to shareholders upon written request to the Treasurer, United Canso Oil & Gas Ltd., Box 2544, Station M, Calgary, Alberta T2P 3X6

Highlights

Financial
(thousands of Canadian dollars, except per share amounts)

	1984	1983
Revenue	**$ 43,435**	$ 33,825
Expenses	**81,234**	126,750
Loss from continuing operations	**35,194**	88,265
Per share	**5.05**	12.78
Net Loss	**38,704**	90,789
Per share	**5.56**	13.15
Funds generated from (used in) operations	**7**	(7,962)
Property and equipment expenditures	**8,299**	27,780
Total assets	**155,540**	203,790
Long term debt	**175,144**	181,640

Operating

	1984	1983
Daily Production (before royalties)		
Crude Oil and Natural Gas Liquids — cubic metres	**378**	336
Natural Gas — thousands of cubic metres	**873**	747
Reserves (before royalties) at year end		
Crude Oil and Natural Gas Liquids — thousands of cubic metres		
Proved	**1306***	1686
Probable	**54***	992
Natural Gas — millions of cubic metres		
Proved	**4964***	6197
Probable	**896***	2351
Drilling Activity		
Gross Wells	**95**	87
Net Wells — successful	**27.1**	22.3
dry	**0**	1.0
Land Holdings — thousands of hectares — year end		
Gross	**569***	11,172
Net	**134***	1,698

*Decrease is primarily the result of the disposition of the Australian properties.

Directors' Report to the Shareholders

Fiscal 1984 was a period of retrenchment, during which the Company consolidated its operations. During this time, a restructuring agreement was signed with the Company's principal lender, The Royal Bank of Canada. Negotiations continued with two other major creditors, our Debentureholders for their Convertible Debentures, and with the Canadian Imperial Bank of Commerce for its loan covering our Calgary real estate interests. The Restructuring Agreement provides for the reorganization of the majority of the Company's bank debt from a demand loan to a term loan basis. In addition, the agreement envisions the payment of a portion of the bank interest in a non-cash form, which will assist in financing increased development drilling in Canada. It is expected that our development drilling program will generate sufficient revenue to enable the Company to commence repayment of the bank debt over a thirteen year period. The fiscal 1985 capital budget of $10 million will be concentrated on developing oil prospects in Saskatchewan. No exploratory drilling is planned.

During the year, the Company's cash drain from financing the operations of its industrial division and its Australian subsidiary was eliminated by selling these entities. These sales also provided funds to reduce the bank debt. In the case of Canso Resources Limited (Australia), the sale freed the Company from a commitment to fund the drilling of the Mogga #1 exploratory well at a cost of approximately $6 million; the well was subsequently drilled and abandoned by Flinders Petroleum N.L., the purchaser of the Canso Resources Limited shares. However, the well earned a 12% interest in the 10.4 million acre farmout block. United Canso received a 15% shareholding in Flinders Petroleum N.L. as part of the consideration for the sale of the Canso Resources Limited shares. This shareholding retains for the Company the upside potential of the Australian operations (particularly in the Mereenie Field, which is now on production), by way of a relatively small investment in Flinders, which will not require any further cash commitment.

Despite recording a loss during the year of $38.7 million, the Company generated funds from operations. This improvement from the prior year, in which funds of $8 million were used in operations, is attributed to an increase of 28% in revenue as a result of development oil drilling and increased gas sales. The 1984 results include several significant nonrecurring events, consisting of a loss on the sale of the Australian subsidiary of $18.1 million, a writedown of other assets of $9.7 million and losses related to discontinued operations of $3.5 million.

The Company anticipates improved financial results, mainly in cash flow, during fiscal 1985, as a result of streamlined operations and the Royal Bank Debt Restructuring Agreement. With successful completion of negotiations on the remaining financial obligations with the Debentureholders and The Canadian Imperial Bank of Commerce, we believe the Company will be in a position to take advantage of any recovery in the oil and gas industry. In all events, the continued cooperation and support of our major creditors will be required.

We appreciate the support the Shareholders have shown in the past year, and commend the staff for their faithful efforts.

Respectfully submitted on behalf of the Board of Directors

Billy R. Delp

B. R. Delp
Chairman of the Board

Jim Taylor

J. M. Taylor
President and Chief Executive Officer

Exploration and Development

The Company participated in the drilling of 95 wells during the past fiscal year of which 88 wells were productive for a success rate of 93%. Drilling activity in 1984 compared to 1983 for gross and net wells was up by 9% and 17% respectively. Of the 95 wells drilled in fiscal 1984, 33 wells were drilled at no cost to the Company as a result of farmout agreements.

Drilling

	1984								1983							
	Oil		Gas		Dry		Total		Oil		Gas		Dry		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
EXPLORATION																
Canada	0	0	1	0.1	3	0	4	0.1	10	0.8	1	0.1	11	0.8	22	1.6
U.S.A.	0	0	0	0	0	0	0	0	2	0.1	0	0	0	0	2	0.1
Australia	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub-Total	0	0	1	0.1	3	0	4	0.1	12	0.9	1	0.1	11	0.8	24	1.7
DEVELOPMENT																
Canada	48	12.6	33	13.4	4	0	85	26	23	10.6	33	10.3	2	0.1	58	21.0
U.S.A.	0	0	0	0	0	0	0	0	0	0	0	0	1	0.1	1	0.1
Australia	6	1.0	0	0	0	0	6	1	2	0.3	1	0.1	1	0.1	4	0.5
Sub-Total	54	13.6	33	13.4	4	0	91	27	25	10.9	34	10.4	4	0.3	63	21.6
TOTAL	54	13.6	34	13.5	7	0	95	27.1	37	11.8	35	10.5	15	1.0	87	23.2

Some columns may not add due to rounding.

Canada

Willesden Green, Alberta

In June 1984 production commenced from three wells completed in the Belly River formation. The Company is the operator of this property and prior to payout has a 75% working interest. Both the gas and oil are produced to a battery, with the gas then being processed at a gas plant in the area. Due to plant capacity limitations, production rates have been restricted to 42 x 10^3m^3/d (1.5 MMcf/d) of gas sales and approximately 12 m^3/d (75 BOPD) of oil.

Princess, Alberta

An active development drilling program was undertaken on this property to develop gas deliverability to satisfy a renegotiated gas purchase contract. The Company has a 60% working interest in 9 wells drilled in late 1983 and early 1984 for shallow gas reserves in the Second White Specks, Medicine Hat and Milk River formations. Gas sales will be significantly augmented as a result of this drilling which has increased deliverability from 13 to 72 x 10^3m^3/d (0.5 to 2.5 MMcf/d). The Medicine Hat and Milk River drilling results were particularly encouraging as these formations had not been extensively tested in the past. The average production rate for these wells was 4 x 10^3m^3/d (140 Mcf/d). Approximately 40 locations can be drilled on 64 hectare (160 acre) spacing in the future for additional deliverability.

Redcliff, Alberta

Fourteen wells were drilled on this Company operated property in fiscal 1984. The drilling provided additional Medicine Hat and Milk River production to supplement current deliverability for the gas purchase contract. Infill drilling of the Medicine Hat formation reflected a spacing unit reduction to 64 hectares (160 acres), whereas the Milk River development was the first concerted effort to place this zone on production.

In the prospective Milk River area there were two wells drilled which are now producing at 2.5 x 10^3m^3/d (90 Mcf/d) per well and provide the Company a favourable economic return. Indications are that approximately 3,900 hectares (9,750 acres) of land, in which the Company has an interest, can be developed for Milk River production on 64 hectare (160 acre) spacing. Drilling will continue in 1985 to develop the required deliverability to meet the gas purchase contract requirements.

Wilson Creek, Alberta

The Company participated to its 12.5% interest in a second successful development well at 16-15-44-4 W5M as a further follow-up to the dual zone oil discovery in 14-15-44-4 W5M drilled in fiscal 1983. The production capability of the three wells is approximately 35 m^3/d (220 BOPD), however production from these wells is currently restricted by a production allowable to 17 m^3/d (107 BOPD).

Lomond-Badger, Alberta

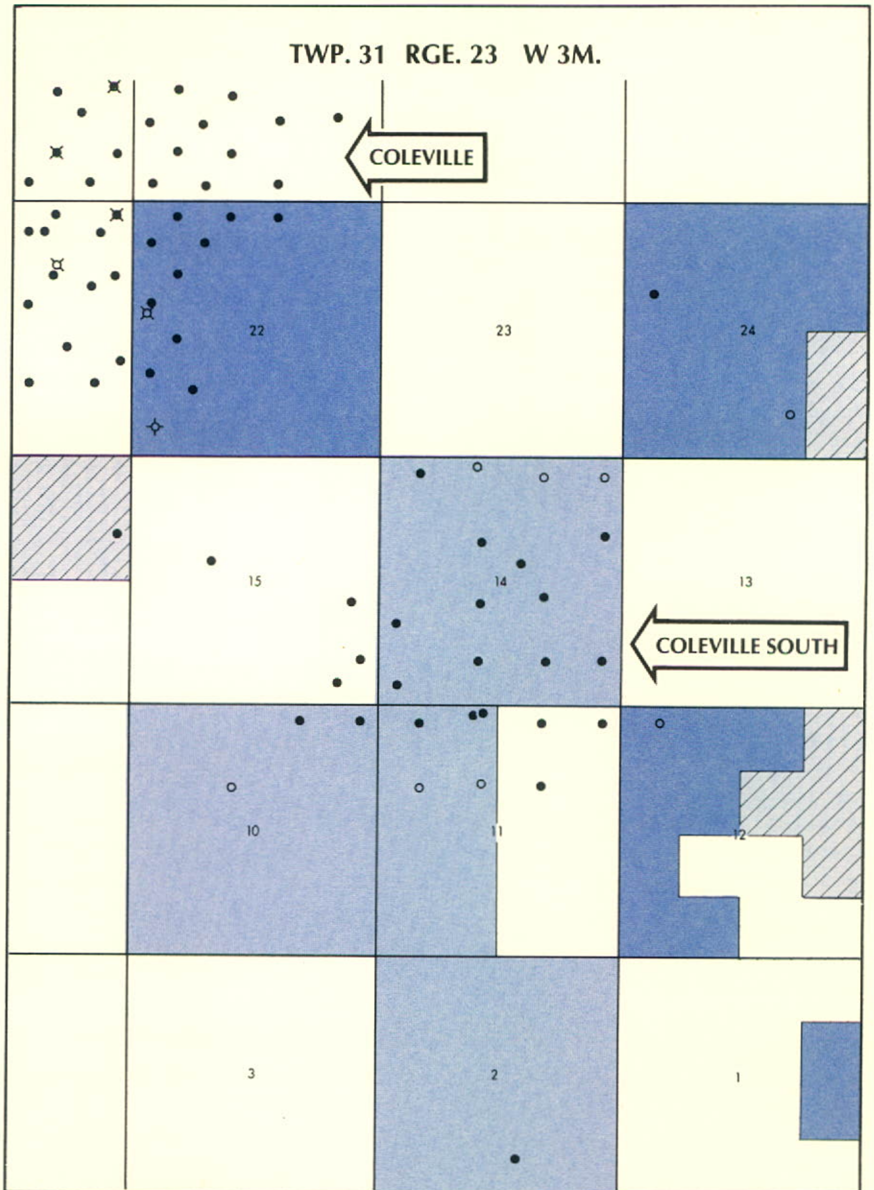
The Company participated to its 25% working interest in a successful development well at 12-19-16-17 W4M. Initial production testing indicates a crude oil production rate of 9 m^3/d (57 BOPD). An additional five miles of seismic was shot during fiscal 1984 to determine further development locations.

Coleville South, Saskatchewan

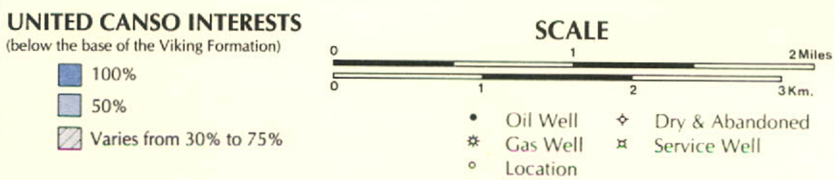
Development drilling activity continued in this area where the Company has a significant land position. In fiscal 1984, seven wells were drilled and cased for Bakken formation heavy oil production. The Company's working interest production, before royalty, averaged 35 m^3/d (220 BOPD) at fiscal year end. Production from all wells receives the New Oil Reference Price and is Crown royalty free for one year from commencement of production.

Additional step-out drilling is anticipated in early 1985 to further delineate the Bakken pool. Infill drilling is also anticipated when the Saskatchewan Government approves the reduction of drilling spacing units to 8 hectares (20 acres). Twenty-five new wells are forecast for 1985 which could double current production.

Enhanced recovery is planned in the near future and initially the Bakken pool is expected to be waterflooded as this technique has proven successful in an adjacent Bakken heavy oil pool.



COLEVILLE AREA SASKATCHEWAN
BAKKEN OIL PROSPECT



For clarity only wells drilled below the base of the Viking Formation are illustrated

Production

Crude Oil and Natural Gas Liquids

Canada

During fiscal 1984, the Company's production of crude oil and natural gas liquids averaged 378 m^3/d (2,378 BOPD), which was an increase of 16% over that of 1983. This production increase was achieved by the addition of new wells, primarily in Saskatchewan, which more than offset the productivity decline of wells in the mature fields. Increased production allowables in Alberta plus the new production from Willesden Green also had a positive impact on overall crude oil and liquids production.

United States

As a result of the sale of the Company's producing properties in the United States, effective January 1, 1983, there were no sales of crude oil and liquids in fiscal 1984.

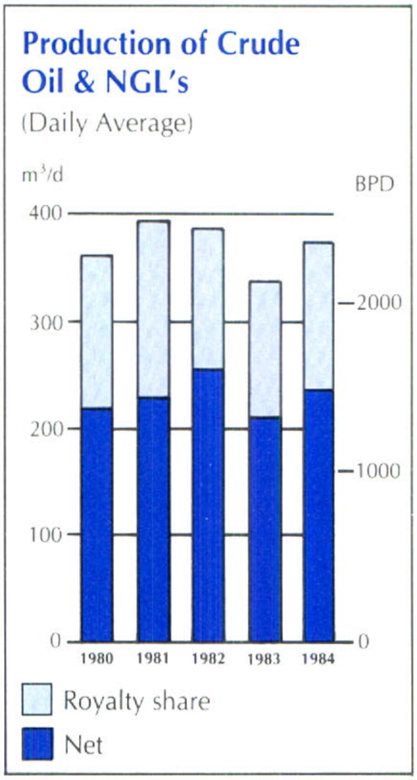
Natural Gas

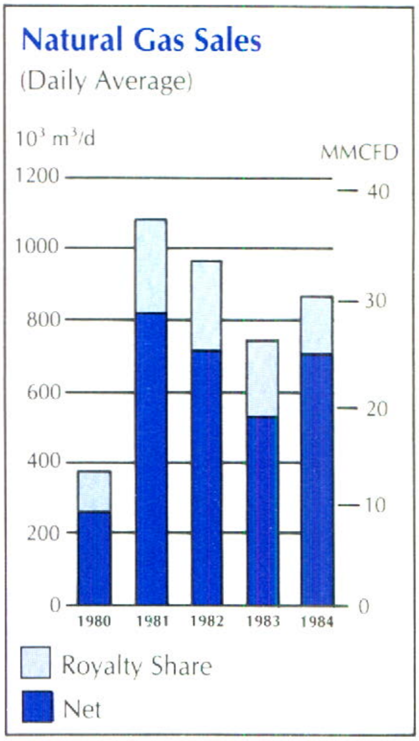
Canada

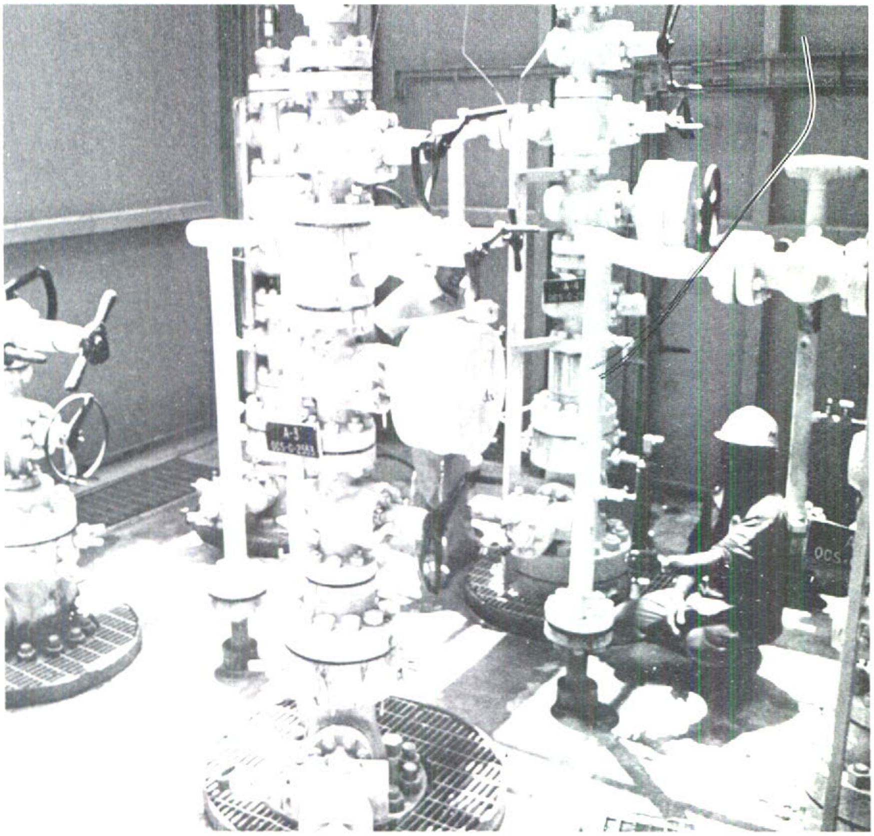
Gas sales in 1984 averaged 821 x $10^3m^3/d$ (29.1 MMSCFD), which was a 17% increase over the 1983 level. This increase in gas sales was attributable to the following: gas nomination levels in 1984 were approximately 3% greater than in the previous year; in Princess the gas contract rates were re-established at the original levels; the Rowley project, which commenced production in September 1983, achieved a full year of sales in 1984; the Willesden Green and Tide Lake fields commenced production in 1984; and Redcliff gas sales were augmented by a development drilling program.

United States

The average gas production rate from the one remaining Company property in the United States located offshore Louisiana was 52 x $10^3m^3/d$ (1.9 MMSCFD) in 1984. Production capability is estimated to be 750 x $10^3m^3/d$ (27 MMSCFD). The Company has a 9% working interest in this property.

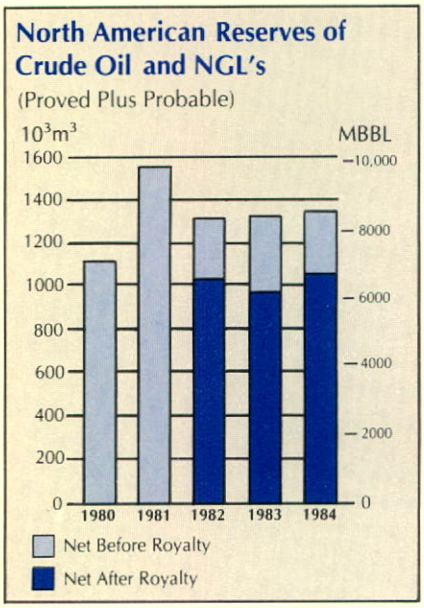


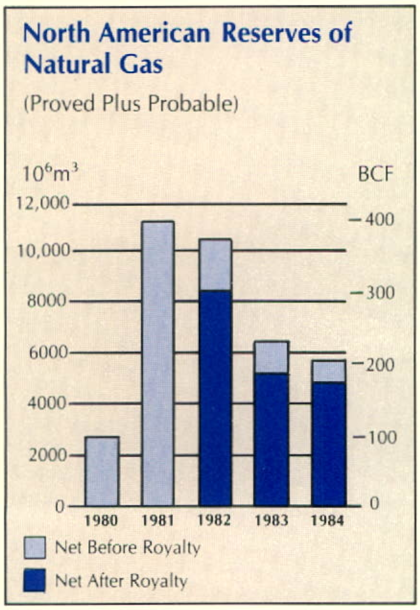


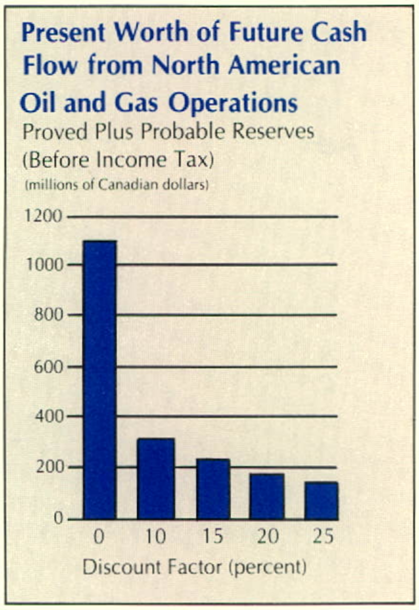


Reserves

The crude oil and natural gas reserves of the Company as well as the projected future cash flow from these reserves have been evaluated by Company staff.







Crude Oil and Natural Gas Liquids (m^3) (Net Before Royalty)

	CANADA		UNITED STATES		AUSTRALIA		TOTAL	
	Proved	Probable	Proved	Probable	Proved	Probable	Proved	Probable
At September 30, 1983	1,050,795	292,166	—	—	636,000	700,000	1,686,795	992,166
Added by Drilling	76,000	—	—	—	—	—	76,000	—
Revision of Prior Estimate	320,287	(236,909)	—	—	—	—	320,287	(236,909)
Sale of Property	3,086	1,038	—	—	636,000	700,000	639,086	701,038
Production	137,970	—	—	—	—	—	137,970	—
At September 30, 1984	1,306,026	54,219	—	—	—	—	1,306,026	54,219

Natural Gas (10^6m^3) (Net before Royalty)

	CANADA		UNITED STATES		AUSTRALIA		TOTAL	
	Proved	Probable	Proved	Probable	Proved	Probable	Proved	Probable
At September 30, 1983	5,084	1,355	28	22	1,085	974	6,197	2,351
Added by Drilling	—	—	—	—	—	—	—	—
Revision of Prior Estimate	195	(459)	9	(22)	—	—	204	(481)
Sale of Property	33	—	—	—	1,085	974	1,118	974
Production	300	—	19	—	—	—	319	—
At September 30, 1984	4,946	896	18	—	—	—	4,964	896

Notes:

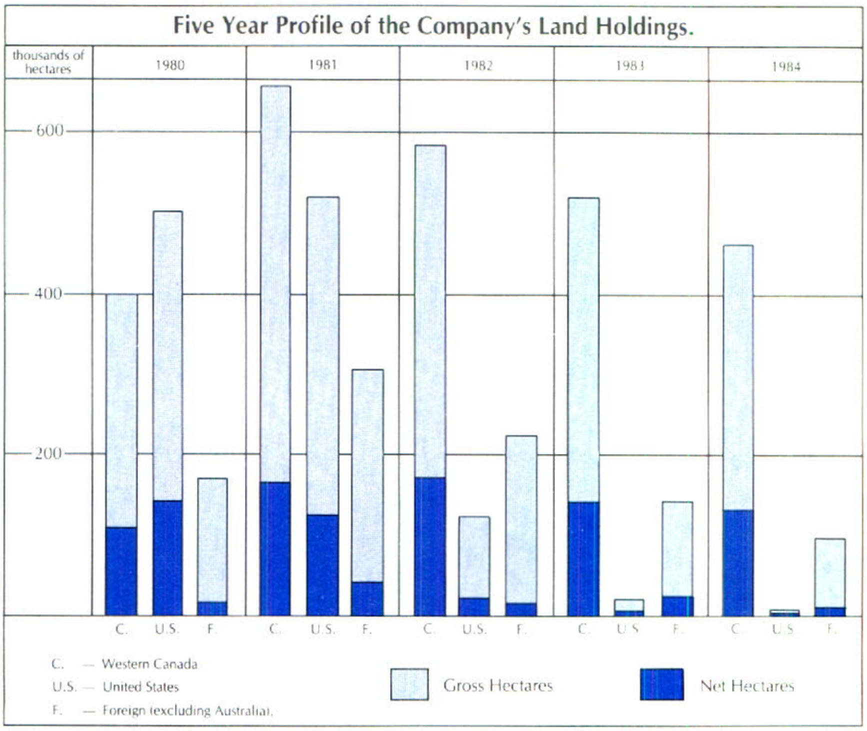
1) The proved crude oil and natural gas reserves are considered to be recoverable under current technology and present and anticipated economic conditions (assuming price escalations at 5% to 6% per annum), from that portion of the reservoir, which can be reasonably evaluated as economically productive 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.
2) Probable reserves are those which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery.
3) The reserves are net before royalties, taxes or burdens.
4) Cash flow forecasts, utilizing price forecasts discussed below and discount methods to reflect current values, have been developed to illlustrate the value of the reserves.
5) Crude oil prices were increased in the 5% to 6% range per year commencing in 1986. Natural gas prices were adjusted in a similar manner to that of oil prices. The impact of the currently depressed gas market was considered, with gas nominations increasing from their current levels to a 100% take level in the contract year 1988-1989.
6) S.I. or metric units can be converted to traditional units by using the following conversions:
   liquid — 1 cubic metre = 6.29 barrels gas — 1 cubic metre = 35.49 cubic feet

Land

Canada

In 1984, emphasis continued to be placed on generating industry interest in the Company's undeveloped acreage.

During the fiscal year, 16 farm-out agreements were consummated, affecting more than 7,200 net hectares (18,000 net acres), resulting in a total of 33 wells being drilled by other parties on Company held acreage. As well, numerous pooling agreements, acreage sales and options, were entered into affecting a further 28,000 net hectares (70,000 net acres). The most significant acreage sale was that of more than 25,600 net hectares (64,000 net acres) in Manitoba.

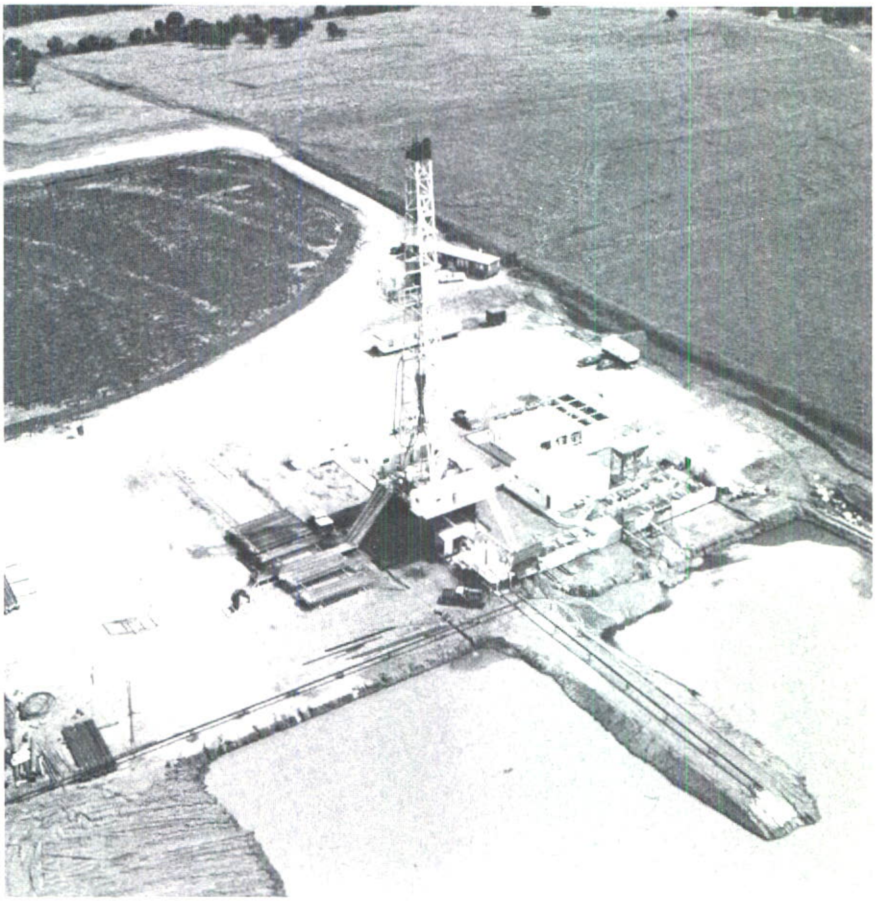


International

The Company continued to reduce its commitment to international ventures by way of surrender or sale of various foreign interests.

Recently, the Company entered into an agreement to sell its partially paid up shareholding in Georex Iberica S.A., which held interests in two offshore Spanish permits, thereby eliminating certain imminent expenditure commitments.

As a result of this sale and the surrender of other foreign interests, the Company's only remaining foreign holdings are a 20% working interest in the Tarragona "C" permit, a carried interest in the Delta "E" permit, both located offshore Spain, and a 1.25% working interest in two permits, located offshore Ireland.



Australia

Effective April 26, 1984, the Company exchanged the shares of its wholly owned Australian subsidiary, Canso Resources Limited, for a 15% shareholding in Flinders Petroleum N.L. together with a cash consideration.

Prior to the sale of Canso Resources Limited, the well Canso Mogga-1 was spudded on the ATP 239P block in Queensland. This well was required under the terms of a farmout agreement encompassing more than 4 million hectares (10 million acres) in central Queensland. The well was drilled to a total depth of 3,620 metres (11,878 feet), and was dry and abandoned; the rig was released on November 4, 1984. As a result of drilling this well to contract depth, a 12% working interest was earned in the farmout block.

In addition, the Company participated in six successful development wells in the Mereenie oil field in the Amadeus Basin, Northern Territory prior to the sale of Canso Resources Limited.

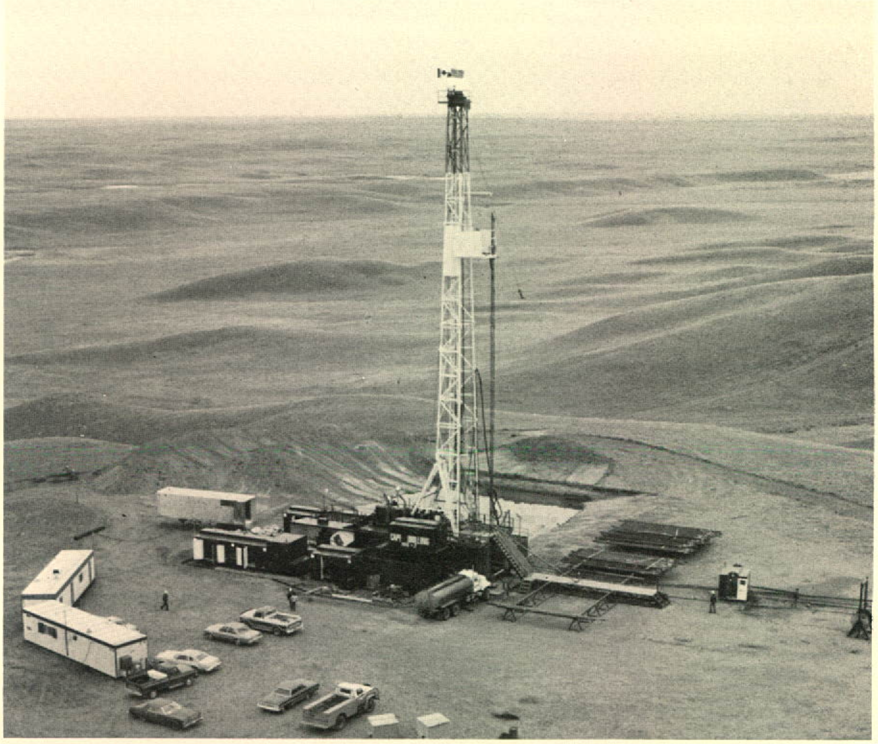
As a result of the sale of Canso Resources Limited, the Company holds no direct working interests in Australia. Consequently a significant reduction of the Company's land holdings has resulted.

Land Holdings

	Summary as of September 30, 1984			
	Gross Hectares	Net Hectares	Gross Acres	Net Acres
CANADA				
Alberta	334,598	102,103	826,751	252,284
British Columbia	45,285	7,170	111,895	17,716
Saskatchewan	92,271	18,110	227,990	44,747
Sub-Total	472,154	127,383	1,166,636	314,747
INTERNATIONAL				
United States	4,047	364	10,000	900
Europe	93,009	6,072	229,814	15,002
Sub-Total	97,056	6,436	239,814	15,902
TOTAL	569,210	133,819	1,406,450	330,649

Industrial

In 1984, the Company achieved its objective of divesting itseif of its Industrial Division. The assets of Lift Systems International, a division of the Company which fabricated oilfield pumping units, were sold effective June 16, 1984. In addition, the shares of Heritage Industries Ltd. whose sole asset was a foundry business in Winkler, Manitoba, were sold to a private company, effective July 1, 1984.



Management Discussion and Analysis of Financial Condition and Results of Operations

1984 Fiscal Year

Results of Operations

The financial statements of the Company are stated in Canadian dollars and have been prepared in accordance with accounting principles generally accepted in Canada which, in the case of the Company, conform in all material respects with those in the United States except as described in Note 14 to the Consolidated Financial Statements.

United Canso recorded a net loss of $38.7 million or $5.56 per share during the 1984 fiscal year, compared to a net loss of $90.8 million or $13.15 per share in 1983. Reference should be made to Note 18 of the Consolidated Financial Statements in which revenues, operating loss (income) and assets by geographic areas are presented.

The net loss in 1984 included a number of non-recurring events including a loss on sale of the Company's Australian subsidiary in the amount of $18.1 million, a writedown of other assets of $9.7 million, a loss on discontinued operations of $2.5 million and an extraordinary loss from disposal of discontinued operations of $1.0 million.

Consolidated revenue increased by 28% to $43.4 million in 1984 from $33.8 million in 1983. Crude oil revenue of $17.1 million is 26% higher than the $13.6 million recorded in 1983 primarily as a result of development drilling which increased production in fiscal 1984. Natural gas revenue increased by 29% to $25.5 million in 1984 from $19.7 million, primarily due to a new area on production in fiscal 1984.

Oil and gas operating expenses of $6.4 million increased 20% from $5.4 million in fiscal 1983 due to the increase in crude oil and natural gas production as discussed above.

The Petroleum and Gas Revenue Tax increased 61% from $2.9 million in 1983 to $4.6 million in 1984 due to the increase in sales volumes of oil and natural gas in Canada and an increase in the effective rate of tax from 11% to 12% effective July 1, 1983.

General and administrative expenses declined by 26% to $3.6 million in 1984 compared to $4.9 million in 1983, due to general cost-cutting measures and overall administrative staff reductions including those necessary to administer U.S. properties.

Interest on long term debt in 1984 increased 3% to $28.1 million in 1984 from $27.3 million in 1983, primarily as a result of interest accrued on outstanding taxes payable and interest accrued on interest not paid on the 10½% Convertible Subordinated Debentures.

Depletion, depreciation and amortization for 1984 decreased 34% to $10.6 million from $15.9 million in 1983. The writedown of oil and gas properties of $66.3 million in 1983 was the principal reason for the reduced depletion, depreciation and amortization provision in 1984. Also, a revaluation of the Company's reserves at year end led to a significant increase in the estimated future revenues from these reserves, upon which the depletion provision is based. This was offset partially by the increase in oil and gas revenues in 1984 as compared to 1983.

A loss of $18.1 million was recorded on the disposition of the Company's Australian subsidiary which was sold effective April 26, 1984.

Writedowns of other assets in fiscal 1984 of $9.7 million and $0.7 million in 1983 are more fully described in Note 5 to the Consolidated Financial Statements.

The Alberta Royalty Tax Credit decreased 15% to $2.4 million in 1984 as compared to $2.8 million in 1983 as a result of a reduction in the rate of the credit from 75% to 50% of Alberta Crown Royalties paid effective January 1, 1984 offset by increased Alberta oil and gas revenues.

The current income tax provision decreased as a result of the corporate reorganization which merged the operations of three profitable Canadian subsidiaries with United Canso Oil & Gas Ltd., resulting in one corporate entity with operating losses and accordingly no current taxes payable.

During 1983, the Company recorded income tax reductions to the extent of deferred income taxes payable. Any future recoveries will be recorded in the accounts only when realized. No recoveries were realized in fiscal 1984.

Funds were generated from operations in 1984 in the amount of $7,000 as compared to funds used in operations in fiscal 1983 of $8.0 million. This improvement is as a result of increased revenues in fiscal 1984 as compared to fiscal 1983. The overall decrease in working capital of $3.3 million is partially attributable to repayment of long term debt in fiscal 1984.

Capital Expenditures and Commitments

Capital expenditures in 1984 totalled $8.3 million, a reduction of 70% from $27.8 million in the prior year. Canadian capital expenditures decreased $6.7 million from 1983 to total $4.7 million, while net expenditures in the United States declined $2.5 million to nil in 1984 due to the sale of the majority of these assets January 1, 1983. Australian expenditures decreased $10.3 million to $3.6 million in 1984 from those incurred in fiscal 1983.

Capital commitments are limited to development programs in Canada with no active exploratory work being undertaken.

Future Operations and Liquidity

As a result of depressed market conditions and reduced prices in the oil and gas industry, the Company has incurred significant operating losses during the years ended September 30, 1984, 1983 and 1982 and at September 30, 1984 had an accumulated deficit of $149.4 million and a working capital deficiency of $63.0 million which deficiency results largely from the 10½% Convertible Subordinated Debentures that are due and payable and as a result of loans payable on account of real estate purchased in fiscal 1981. The Company has pursued possible methods of reducing or restructuring its debt obligations which have resulted in the signing in October 1984 (amended in November 1984) of a Debt Restructure Agreement with its principal lender, The Royal Bank of Canada, to be effective from July 1, 1984. Demand production loans previously outstanding of approximately $169.0 million have been rescheduled over periods varying from five to thirteen years. As part of the Debt Restructure Agreement the Company has agreed to meet certain conditions and covenants. These conditions and covenants are more fully discussed in Note 2 of the Consolidated Financial Statements.

Failure to comply with covenants contained in the Debt Restructure Agreement would constitute an event of default and would give the lender the option to cause all outstanding debt and interest under the agreement to become due and payable.

The Company's existence as a going concern is dependent upon meeting the significant covenants under the Debt Restructure Agreement and its ability to attain profitable operations. If, as a result of a default, or otherwise, the support of the lenders, including the holders of the 10½% Convertible Subordinated Debentures and the holder of the majority of outstanding real estate loans is withdrawn, the Company may be unable to realize its assets and discharge its liabilities in the normal course of business. The Company's ability to meet the covenants under the Debt Restructuring Agreement and to attain profitable operations is not assured.

Inflation Accounting

In October, 1982 the Canadian Institute of Chartered Accountants issued a Recommendation entitled Reporting the Effects of Changing Prices which requires the disclosure of information related to the effects of inflation on the financial statements, beginning with the 1984 fiscal year of the Company. Disclosures as required for fiscal 1984 are included as unaudited Supplementary Financial Information in this annual report.

1983 Fiscal Year

Results of Operations

United Canso recorded a net loss of $90.8 million or $13.15 per share during the 1983 fiscal year, compared to a net loss of $47.1 million or $6.85 per share in 1982. Reference should be made to Note 18 to the Consolidated Financial Statements in which operating income, revenues and assets by geographic area are presented.

Consolidated revenue decreased by 15% to $33.8 million in 1983 from $39.6 million in 1982. Crude oil revenue of $13.6 million was 16% lower than the $16.1 million recorded in 1982 as a result of the sale of the majority of the Company's United States oil and gas assets effective January 1, 1983. Natural gas revenue decreased 13% to $19.7 million in 1983 from $22.7 million in 1982, primarily due to the reduced volumes of gas taken by purchasers during the 1983 fiscal year as a result of depressed gas markets.

Oil and gas operating expenses of $5.4 million decreased 27% from $7.3 million in 1982, due to the sale of the Company's United States properties and a revision of throughput agreements on Company owned gas plants whereby operating cost recoveries were realized.

The Petroleum and Gas Revenue Tax decreased 28% from $4.0 million in 1982 to $2.9 million in 1983, mainly due to the decline in sales volumes of natural gas in Canada. In addition, the effective rate of tax dropped from 12% to 11% effective July 1, 1982.

General and administrative expenses fell 36% to $4.9 million in 1983 compared to $7.7 million in 1982, due to general cost-cutting measures and overall administrative staff reductions, as well as reduced United States operations in 1983.

Interest on long term debt in 1983 decreased 4% from $28.4 million in 1982 to $27.3 million in 1983, as interest rates stabilized in 1983 at slightly lower levels than in 1982.

Depletion, depreciation and amortization for 1983 decreased 6% to $15.9 million from $16.9 million in 1982. The reduction in gas sales, coupled with the sale of the U.S. properties effective January 1, would have resulted in a substantial decrease in depletion for 1983. However, a revaluation of the Company's reserves at the 1983 fiscal year end led to a major reduction in the estimated future revenues from those reserves, upon which the depletion provision is based. The effect of this revaluation was to increase the 1983 depletion provision by approximately $8.0 million.

The carrying value of the Canadian oil and gas assets was written down by $66.3 million in fiscal 1983. The maximum carrying value was determined in accordance with Securities and Exchange Commission regulations. Under those regulations, the future cash flows of proven reserves only are estimated, assuming no future price increases except where specifically provided for by contract. The resulting cash flow is discounted using a discount rate of 10% and is adjusted to reflect estimated future income taxes. In the calculation of income taxes, the Company's future interest costs could not be included. The effect of this non-deductibility was to increase the writeoff significantly.

The $3.4 million loss on the sale of the Company's United States oil and gas assets was occasioned by the continuing deterioration in the value of those assets subsequent to the valuation undertaken in 1982.

The Alberta Royalty Tax Credit decreased 33% to $2.8 million in 1983 from $4.1 million in 1982 as a result of a decrease in Alberta oil and gas revenues and related crown royalties in fiscal 1983.

The current income tax provision increased $1.9 million to $1.5 million in fiscal 1983 from a recovery of $0.4 million in fiscal 1982 due to operating Canadian subsidiaries of the Company becoming taxable.

A recovery of deferred income taxes previously recorded was also reflected in the accounts for fiscal 1983. The remainder of benefits of future reductions as a result of losses in that year were not recorded and will not be recorded until realized.

Funds used in operations in 1983 decreased $0.9 million to $8.0 million from $8.9 million in 1982. The overall decrease in working capital reflected the reclassification of the $50 million 10½% Convertible Subordinated Debentures to amounts due within one year, as more fully described in Note 7 to the Consolidated Financial Statements.

Capital Expenditures and Commitments

Capital expenditures in 1983 totalled $27.8 million, a reduction of 19% from $34.3 million in the previous year. Canadian capital expenditures rose $5.0 million from 1982 to total $11.4 million, while expenditures in the United States declined $12.0 million to $2.5 million in 1983 due to the sale of those assets January 1, 1983. Australian expenditures of $13.9 million remained at approximately the same level as in 1982.

Summary of Quarterly Financial Results

(unaudited)

For The Years Ended September 30, 1984 and 1983

		Loss (Earnings) before Extraordinary Item		Loss (Earnings)		Funds used in (Generated from)
	Revenue	Amount	Per Share	Amount	Per Share	Operations
	(thousands of Canadian dollars, except per share amounts)					
First Quarter						
1984	$12,913*	$ (588)	$ (0.08)	$ (588)	$ (0.08)	$(1,999)*
1983	9,958*	2,448	0.36	2,448	0.36	575*
Second Quarter						
1984	13,990	24,637	3.54	26,141	3.75	(4,812)
1983	9,926*	2,789	0.41	2,789	0.41	891*
Third Quarter						
1984	8,498	7,014	1.01	6,541	0.94	2,768
1983	8,514*	1,066	0.16	1,066	0.16	(562)*
Fourth Quarter						
1984	8,034	6,610	0.95	6,610	0.95	4,036
1983	5,427*	84,486	12.23	84,486	12.23	7,058*
Year						
1984	43,435	37,673	5.41	38,704	5.56	(7)
1983	33,825*	90,789	13.15	90,789	13.15	7,962*

*Restated to reflect reclassification of subsequently discontinued operations.

Market Prices of Common Shares

	Toronto Stock Exchange		Pacific Stock Exchange	
	High	Low	High	Low
	(Canadian dollars)		(U.S. dollars)	
First Quarter				
1984	$4.75	$3.20	$3.81	$2.56
1983	4.65	3.50	4.00	2.44
Second Quarter				
1984	4.45	2.86	3.63	2.31
1983	5.38	3.70	4.38	3.00
Third Quarter				
1984	3.15	1.55	3.38	1.25
1983	6.50	3.85	5.25	3.06
Fourth Quarter				
1984	2.25	1.50	1.69	1.13
1983	7.38	4.65	5.88	3.56
Year				
1984	4.75	1.50	3.81	1.13
1983	7.38	3.50	5.88	2.44

The number of registered holders of common shares of the Company as of December 31, 1984 was 8,214. During the past five fiscal years no cash dividends have been paid by the Company. In addition, there are no plans to pay a dividend on the common shares within the foreseeable future. In general, dividends paid to residents of the United States are subject to a 15% Canadian withholding tax under the current tax treaty between Canada and the United States.

Consolidated Statement of Loss

Three Years Ended September 30,1984
(thousands of Canadian dollars, except share and per share amounts)

	1984	1983	1982
Revenue			
Crude oil	**$ 17,112**	$ 13,582	$ 16,112
Natural gas	**25,453**	19,699	22,671
Interest	**94**	200	455
Other	**776**	344	365
	43,435	33,825	39,603
Expenses			
Operating			
Crude oil and natural gas	**6,437**	5,361	7,325
Petroleum and Gas Revenue Tax	**4,615**	2,862	3,992
General and administrative	**3,626**	4,933	7,691
Interest on long term debt	**28,143**	27,326	28,440
Depletion, depreciation and amortization	**10,552**	15,875	16,859
Writedown of oil and gas properties (Note 12)	**—**	66,300	23,814
Loss on sale of Australian subsidiary (Note 4)	**18,130**	—	—
Writedown of other assets (Note 5)	**9,731**	692	—
Loss on sale of United States oil and gas properties (Note 13)	**—**	3,401	—
	81,234	126,750	88,121
Loss from continuing operations before income taxes and extraordinary item	**37,799**	92,925	48,518
Provision for income taxes (Note 8)			
Alberta Royalty Tax Credit	**(2,367)**	(2,775)	(4,134)
Current	**(238)**	1,556)	(366)
Deferred	**—**	(3,441)	(6,175)
	(2,605)	(4,660)	(10,675)
Loss from continuing operations before extraordinary item	**35,194**	88,265	37,843
Loss from discontinued operations (Note 9)	**2,479**	2,524	5,597
Loss before extraordinary item	**37,673**	90,789	43,440
Extraordinary item—loss on disposal of discontinued operations	**1,031**	—	3,646
Net loss	**$ 38,704**	$ 90,789	$ 47,086
Loss per share			
From continuing operations	**$ 5.05**	$ 12.78	$ 5.51
From discontinued operations	**$ 0.36**	$ 0.37	$ 0.81
Before extraordinary item	**$ 5.41**	$ 13.15	$ 6.32
After extraordinary item	**$ 5.56**	$ 13.15	$ 6.85
Weighted average number of common shares outstanding	**6,965,710**	6,904,450	6,871,112

The accompanying notes are an integral part of these statements.

Consolidated Balance Sheets

September 30, 1984 and 1983
(thousands of Canadian dollars)

ASSETS

	1984	1983
Current		
Marketable securities (at market) (Notes 4, 5)	**$ 7,155**	$ 1,377
Accounts receivable	**8,933**	12,728
Inventories	**307**	1,539
Net assets (liabilities) of discontinued operations (Note 9)	**(89)**	5,158
Other	**734**	702
	17,040	21,504
Investments	**3,222**	3,520
Property and equipment (Note 6)	**131,858**	178,766
Deferred foreign exchange loss (Note 3)	**1,724**	—
Deferred debt restructure fee (Note 7)	**1,696**	—
	$ 155,540	$ 203,790

LIABILITIES AND SHAREHOLDERS' DEFICIENCY

	1984	1983
Current		
Taxes payable	**$ 3,257**	$ 3,201
Accounts payable	**7,018**	14,195
Interest payable	**12,080**	5,086
Long term and other debt due within one year (Note 7)	**57,726**	58,722
	80,081	81,204
Long term debt (Note 7)	**175,144**	181,640
Deferred revenue	**10,983**	12,926
Shareholders' deficiency		
Share capital (Note 10)		
Authorized		
10,000,000 preferred shares, par value $10 each		
25,000,000 common shares, par value $1 each		
Issued		
6,966,603 common shares (1983-6,962,353)	**6,967**	6,962
Contributed surplus	**35,229**	35,218
Less: Advances to former employees to acquire common shares	**(3,444)**	(3,444)
	38,752	38,736
Deficit	**(149,420)**	(110,716)
	(110,668)	(71,980)
Contingencies (Notes 2, 11)		
	$ 155,540	$ 203,790

On Behalf of the Board:

Director George H. Laycraft

Director Robert W. St. Clair

The accompanying notes are an integral part of these statements.

Consolidated Statement of Changes in Financial Position

Three Years Ended September 30, 1984
(thousands of Canadian dollars)

	1984	1983	1982
Source of funds			
Loss before extraordinary item	$ (37,673)	$ (90,789)	$ (43,440)
Items not affecting funds			
Depletion, depreciation and amortization	10,552	15,875	16,859
Writedown of oil and gas properties	—	66,300	23,814
Loss on sale of Australian subsidiary	18,130	—	—
Writedown of other assets	6,936	692	—
Loss on sale of United States oil and gas properties	—	3,401	—
Unrealized foreign exchange loss	678	—	—
Deferred income taxes	—	(3,441)	(6,175)
Other	1,384	—	61
Funds (used in) generated from operations	7	(7,962)	(8,881)
Proceeds from sale of Australian subsidiary net of working capital	18,201	—	—
Less repayment of related long term debt	(11,578)	—	—
Proceeds on disposal of property and equipment	1,246	22,013	—
Increase in deferred revenue	2,069	2,226	5,116
Proceeds from issue of shares	16	317	—
Other	161	—	(73)
	10,122	16,594	(3,838)
Application of funds			
Additions to property and equipment	8,299	27,780	34,316
Decrease (increase) in long term debt	4,078	2,942	(49,910)
Long term and other debt due within one year	(996)	53,734	2,587
Increase (decrease) in investments	1,051	(8,131)	(317)
Quoted investments reclassified to current assets	—	(1,377)	—
Advances to former employees to acquire common shares	—	(12)	3,456
Loss on disposal of discontinued operations	1,031	—	3,646
	13,463	74,936	(6,222)
Increase (decrease) in working capital	$ (3,341)	$ (58,342)	$ 2,384
Comprised of			
Cash	$ —	$ (187)	$ 187
Cash held in trust	—	(488)	488
Marketable securities	5,778	1,377	—
Accounts receivable	(3,795)	1,757	(3,441)
Inventories	(1,232)	65	856
Net assets of discontinued operations	(5,247)	(1,093)	(5,467)
Other	32	86	263
Bank indebtedness	—	—	7,650
Taxes payable	(56)	(2,115)	173
Accounts payable	7,177	(1,638)	5,632
Interest payable	(6,994)	(2,372)	(1,370)
Long term and other debt due within one year	996	(53,734)	(2,587)
Increase (decrease) in working capital	(3,341)	(58,342)	2,384
Working capital deficiency at beginning of year	(59,700)	(1,358)	(3,742)
Working capital deficiency at end of year	$ (63,041)	$ (59,700)	$ (1,358)

The accompanying notes are an integral part of these statements.

Consolidated Statement of Deficit (Retained Earnings)

Three Years Ended September 30, 1984
(thousands of Canadian dollars)

	1984	1983	1982
Balance at beginning of year	**$110,716**	$ 19,927	$(27,159)
Net loss	**38,704**	90,789	47,086
Balance at end of year	**$149,420**	$110,716	$ 19,927

The accompanying notes are an integral part of these statements.

Auditors' Report

To the Shareholders of
United Canso Oil & Gas Ltd.

We have examined the consolidated financial statements of United Canso Oil & Gas Ltd. Our examinations were made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the Company as at September 30, 1984 and 1983 and the results of its operations and the changes in its financial position for each of the years in the three year period ended September 30, 1984 in accordance with accounting principles generally accepted in Canada applied, except for the change, with which we concur, in the method of accounting for foreign currency translation as explained in Note 3 to the consolidated financial statements, on a consistent basis.

Calgary, Canada
December 12, 1984

Clarkson Gordon
Chartered Accountants

Comment on Difference in Canada-United States Reporting Standards for Auditors

The above opinion is expressed in accordance with standards of reporting generally accepted in Canada. Had the report been prepared in accordance with United States reporting standards, our opinion on the 1984 financial statements would have been qualified as being subject to the outcome of the uncertainties described in Notes 2, 7 and 11 to the consolidated financial statements.

Calgary, Canada
December 12, 1984

Clarkson Gordon
Chartered Accountants

Notes To Consolidated Financial Statements

September 30, 1984

1. Summary of significant accounting policies

The financial statements of the Company have been prepared by management on a going concern basis (see Note 2) in accordance with accounting principles generally accepted in Canada which, as applied in these financial statements, are substantially in conformity with accounting principles generally accepted in the United States, except as described in Note 14. Because a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. In management's opinion, the financial statements have been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below.

a) Principles of consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned operating subsidiaries, which are listed below:

Great Basins Minerals Ltd.
Canso Oil & Gas, Inc.
Canso Spain, Inc.
Imput Pty. Limited
Harbetta Pty. Limited (incorporated April 11, 1984)

Merged Subsidiaries

Great Basins Petroleum Ltd.
Great Basins Oil & Gas Ltd.
Loucol Petroleum Ltd.

The excess consideration paid for the shares of subsidiaries over their net book values at dates of acquisition has been attributed to the property and equipment of such subsidiaries.

b) Marketable securities

Marketable securities are carried at the lower of cost and market value.

c) Inventories

Inventories of drilling supplies are valued at the lower of average cost and net realizable value.

d) Investments

Investments are carried at cost and income is recorded only as dividends are declared.

e) Property and equipment

The Company follows the full cost method of accounting for oil and gas operations whereby all costs of exploring for and developing oil and gas reserves are capitalized in two major cost centres: Canada and the United States. Such costs include land acquisition costs, geological and geophysical expense, interest and other carrying charges of non-producing property, costs of drilling both productive and non-productive wells and overhead expense related to exploration and development activities. No gains or losses are recognized upon disposition of oil and gas properties accounted for under the full cost method, unless such disposition would significantly alter the relationship within a cost centre between capitalized costs and proved reserves of oil and gas.

Other property and equipment is carried at cost. Investment tax credits related to equipment are recorded as a reduction of costs. Gains and losses are recognized upon disposition of other property and equipment.

f) Depletion, depreciation and amortization

Depletion and depreciation of capitalized oil and gas costs are calculated at rates for each cost centre based on the proportion of current production revenues to current and estimated future revenues from proved reserves as determined by Company reservoir engineers.

Estimated future revenues are based on current prices except for changes provided by contractual agreements.

Depreciation and amortization of other property and equipment is provided on the straight line or declining balance basis at rates based on the estimated useful lives of the assets ranging from four to twenty years.

g) Debt restructure fee

Debt restructure fees incurred as a result of rescheduling the Company's obligation to The Royal Bank of Canada are deferred and are amortized over the weighted average life of such debt.

h) Joint venture accounting

The majority of the Company's exploration and production activities are conducted jointly with others and, accordingly, the accounts reflect the Company's proportionate interest in such activities.

i) Foreign currency translation

All foreign operations are considered to be integrated with those of the Company and the related financial statements are translated into Canadian dollars using the temporal method.

Under this method, monetary assets and liabilities are translated at rates of exchange prevailing at the balance sheet dates, while non-monetary assets and liabilities are translated at historical rates of exchange. Revenue and expenses are translated at average rates for the year with the exception of depletion, depreciation and amortization which are translated at the rates of exchange used for the related assets.

Unrealized exchange gains and losses on translation of long term debt are deferred and amortized over the remaining term of the related debt. Other exchange gains and losses are included in earnings.

j) Deferred revenue

Payments received for contracted gas volumes not taken by purchasers are recorded as deferred revenue at the end of the contract year for which the payment is made. These amounts will be recorded as revenue upon delivery of the gas or upon the expiry of the period for making up such deficiencies under the specific gas contracts.

k) Income taxes

The Company follows the deferral method of tax allocation accounting under which the income tax provision is based on the income reported in the accounts. The Company makes full provision for income taxes deferred as a result of claiming capital cost allowances and exploration, development and lease acquisition costs and other items permitted by income tax legislation in excess of the related depletion and depreciation provided in the accounts. Investment tax credits are recorded in the accounts when realized and withholding taxes on earnings of foreign subsidiaries are provided when such earnings are remitted to the Company.

l) Loss per share

Loss per share is calculated using the weighted average number of common shares outstanding during the year. The conversion of all obligations and the exercise of all share options have no dilutive effect.

2. Future operations

As a result of depressed market conditions and reduced prices in the oil and gas industry, the Company has incurred significant operating losses during the years ended September 30, 1984, 1983 and 1982 and at September 30, 1984 had an accumulated deficit of $149.4 million and a working capital deficiency of $63.0 million which deficiency results largely from the 10½% Convertible Subordinated Debentures that are due and payable. The Company has pursued possible methods of reducing or restructuring its debt obligations which have resulted in the signing in October 1984 (amended in November 1984) of a Debt Restructure Agreement with its principal lender, The Royal Bank of Canada to be effective from July 1, 1984. Demand production loans previously outstanding of approximately $169.0 million have been rescheduled over periods varying from five to thirteen years. As part of the Debt Restructure Agreement the Company has agreed to the following significant covenants:

(a) The reorganization of the Company's capital, prior to February 28, 1985, increasing the authorized number of voting Common Shares, creating new preferred shares and designating a portion of those Preferred Shares as Series I Convertible Preferred Shares, non-voting, to be available for issue to the principal lender under certain conditions;

(b) Shareholder approval prior to February 18, 1986 of the conversion of the 10½% Convertible Subordinated Debentures into Common Shares at the conversion price of $3.00 per Common Share;

(c) The settlement prior to November 30, 1985 of the majority of outstanding real estate loans of the Company by the issuance of Common Shares at a price of $3.00 per Common Share; and

(d) Realization of minimum net revenue levels for each fiscal year commencing in 1985.

Failure to comply with covenants contained in the Debt Restructure Agreement, including those noted above, would constitute an event of default and would give the lender the option to cause all outstanding debt and interest under the agreement to become due and payable.

In addition to reimbursement of expenses, the principal lender is entitled to certain fees as consideration for rescheduling the Company's obligations. A Restructure Fee is payable in two components. The Company is to issue to its principal lender Common Shares in such number as will be after issuance equal to 7.5 per cent of the total Common Shares outstanding on a fully diluted basis (including dilution for item (b) above). To satisfy the second component, the Company has issued a note for $1.75 million, payable at any time up to 1991, with interest.

Further compensation is also payable to the principal lender in the form of warrants to purchase Common Shares in the event interest on a $24.0 million debenture loan is not paid in cash. (See Note 7A(ii)).

The Company's existence as a going concern is dependent upon meeting the significant covenants under the Debt Restructure Agreement described above and its ability to attain profitable operations. If as a result of a default, or otherwise, the support of the lenders including the holders of the 10½% Convertible Subordinated Debentures and the holder of the majority of outstanding real estate loans is withdrawn, the Company may be unable to realize its assets and discharge its liabilities in the normal course of business. The Company's ability to meet the covenants under the Debt Restructuring Agreement and to attain profitable operations is not assured.

3. Accounting change

Effective October 1, 1983, the Company prospectively adopted foreign currency translation policies as recently recommended by the Canadian Institute of Chartered Accountants. The effect of this change is to translate long term debt repayable in foreign currencies at the rates of exchange prevailing at the balance sheet dates. The resulting exchange loss is deferred and amortized over the term of the related debt. Previously, long term debt repayable in foreign currencies was translated at the rates in effect at the dates the liabilities were incurred and exchange gains and losses were included in earnings only as realized. As a result of this change, at September 30, 1984, long term debt has been increased and a foreign exchange loss has been deferred in the amount of $1.7 million in the consolidated balance sheet and an unrealized foreign exchange loss of $0.7 million has been included in expenses for the year ended September 30, 1984.

4. Sale of Australian subsidiary

In 1984, Flinders Petroleum N.L. ("Flinders") exercised an option to acquire all the shares of Canso Resources Limited, a wholly owned subsidiary of the Company, in consideration for $17.0 million (Aust.) cash and a five year option granted to the Company to purchase 8,083,333 shares of Flinders at $0.50 (Aust.) per share. The proceeds were applied to repay a $9.7 million (Aust.) loan of Canso Resources Limited guaranteed by the Company and to other commitments of the Company in respect of Canso Resources Limited. The disposition of Canso Resources Limited resulted in a loss of $18.1 million (Cdn.).

In connection with the above transaction, the Company acquired all the shares of Harbetta Pty. Limited ("Harbetta") for nominal consideration. In addition, a payment of $4.1 million was made to acquire a loan owing by Harbetta to the former shareholder. Harbetta's principal asset at the time of acquisition consisted of 4,832,000 common shares (19.93% interest) of Flinders. Subsequently, Flinders completed an underwriting to issue shares pursuant to which Harbetta acquired an additional 6,068,000 shares for a consideration of $3.0 million (Aust.). This resulted in the Company retaining a 14.99% interest in Flinders Petroleum N.L. through Harbetta together with the five year option to acquire 8,083,333 shares of Flinders. The investment in Flinders is included in marketable securities in the accompanying consolidated financial statements.

5. Writedown of other assets

Other assets have been written down in order to reflect their estimated net realizable value or their current appraised value.

	1984	**1983**
	(thousands of Canadian dollars)	
Marketable securities (principally Flinders)	**$ 2,795**	$ 391
Real estate	**6,936**	—
Other	**—**	301
	$ 9,731	$ 692

6. Property and equipment

	Investment at Cost	Accumulated Depletion and Depreciation	Net Investment 1984	Net Investment 1983
	(thousands of Canadian dollars)			
Oil and gas properties, including exploration and development expenditures and production equipment	$ 252,968	$ 125,175	**$ 127,793**	$ 167,711
Other property and equipment, including real estate	11,509	7,444	**4,065**	11,055
	$ 264,477	$ 132,619	**$ 131,858**	$ 178,766

In prior years, costs of certain undeveloped properties relating primarily to Australia were excluded from the depletion calculation (1983 - $32.7 million; 1982 - $29.3 million). Interest of $2.0 million (1983 - $3.2 million; 1982 - $6.4 million) incurred up to the date of sale of Australian properties has been capitalized during the year.

Depletion costs per dollar of revenue were $0.25 (1983 - $0.48; 1982 - $0.43).

The following summarizes the net investment in property and equipment by geographic area:

	Investment at Cost	Accumulated Depletion and Depreciation	Net Investment 1984	Net Investment 1983
	(thousands of Canadian dollars)			
Canada	$ 258,621	$ 127,456	**$ 131,165**	$ 144,084
United States	5,856	5,163	**693**	1,497
Australia and other foreign	—	—	**—**	33,185
	$ 264,477	$ 132,619	**$ 131,858**	$ 178,766

7. Long term debt

Reference should be made to Note 2 to the consolidated financial statements with respect to future operations.

	1984	1983
	(thousands of Canadian dollars)	
Bank Loans		
Term loan with interest at prime rate plus 1% (including $20.0 million U.S. with interest at 12.88% to 13.75%) due 1997	$ 135,650	$ —
Debenture loan with interest at greater of prime rate plus 1% or 9% due 1989	24,000	—
Operating loan with interest at prime rate plus 1%	7,382	—
Demand loan with interest at prime rate plus ¾ of 1%	—	104,513
Bankers acceptances with interest at market rates plus ¾ of 1%	—	38,642
Demand loan with interest at LIBOR plus 1¼% (U.S. $30.0 million)	—	35,943
	167,032	179,098
10½% Convertible Subordinated Debentures due 1996	50,000	50,000
Restructure fee note with interest at 12% due 1991	1,750	—
Real estate loans with interest at prime rate plus ¼ of 1%	7,475	8,438
Equipment loan with interest at 10% due 1992	2,601	2,828
Other	4,012	678
	232,870	240,362
Less amounts due within one year	57,726	58,722
	$ 175,144	$ 181,640

A. Bank Loans

Under the terms of the Debt Restructure Agreement effective July 1, 1984 a new line of credit totalling $173.0 million was established and was divided into three separate loans:

i) A term loan of $139.0 million (which includes U.S. $20.0 million) of which $135.7 million is outstanding and which is scheduled to be paid as to principal and interest in varying monthly instalments to April 1997. The loan bears interest at bank prime rate plus 1% payable in cash. In the event such rate exceeds 16% during the five year period commencing July 1, 1984, the lender may accept payment of interest to 16% in the form of Interest Notes due June 30, 1994 which bear interest at 11½% compounded monthly. Interest due in excess of 16% will be paid in the form of Convertible Preferred Shares. The U.S. $20.0 million bears interest at fixed rates varying from 12.88% to 13.75% and is due on various dates to January 1988 in specified amounts on which dates such amounts will be converted to the term loan conditions.

ii) A debenture loan of $24.0 million due June 30, 1989 bearing interest at the greater of bank prime rate plus 1% or 9% payable quarterly. The lender may require payment of interest in cash, in the form of Interest Notes due June 30, 1994 bearing interest at 11½% compounded monthly or by the issuance by the Company of Convertible Preferred Shares. In lieu of Interest Notes and Convertible Preferred Shares, the holder may elect to receive interest for the period July 1, 1984 to September 30, 1985 in the form of Convertible Interest Notes due September 30, 1985. Certain covenants included in the Debt Restructure Agreement with respect to settlement with other lenders have not been met and as a result the holder has elected to receive Convertible Interest Notes for interest in respect of the quarter ended September 30, 1984.

iii) An operating loan of $10.0 million, of which $7.4 million is outstanding, is revolving and carries no specified terms of repayment. The loan bears interest at bank prime rate plus 1%, payable monthly.

B. Convertible Subordinated Debentures

The 10½% Convertible Subordinated Debentures are unsecured and are convertible into Common Shares of the Company at $31.625 per share. The debentures are redeemable at any time at the Company's option at 107.3% to May 31, 1985 and at declining prices thereafter to maturity. Commencing May 31, 1992 the Company is required to provide a sinking fund for redemption in an annual amount of not less than 5% nor more than 7% of the debentures outstanding at May 31, 1991. The Company has not made quarterly payments due under the terms of the debentures for interest accruing since August 31, 1983 and as a result on January 4, 1984, the trustee of the governing indenture served the Company with a notice of default, declaring all outstanding principal and interest due and payable. Although the Company continues negotiations with the debentureholders to restructure the debenture obligation, no assurance can be given that collection will not be pursued in the 1985 fiscal year and accordingly, the total amount due is included in current liabilities in the consolidated balance sheet at September 30, 1984. The Company has agreed to a covenant under the Debt Restructure Agreement which requires conversion of this obligation to Common Shares.

C. Restructure Fee Note

In partial consideration of the Debt Restructure Agreement, the Company will pay the principal lender a fee of $1.75 million evidenced by a note due July 30, 1991 bearing interest at 12% compounded annually.

D. Other

Real estate loans of $5.5 million are due and payable and accordingly have been included in current liabilities along with an additional $2.0 million which amount matures on September 1, 1985.

E. Security

The Company has pledged substantially all its oil and gas properties, assigned production revenues from those properties, made a general assignment of book debts and issued a floating charge debenture on its assets.

Approximate instalments of long term debt due in each of the years 1986 to 1989 are (in thousands of Canadian dollars): 1986 - $5,791; 1987 - $5,308; 1988 - $10,241; and 1989 - $34,577.

8. Income taxes

Deferred income taxes are provided as follows:

	1984	1983	1982
	(thousands of Canadian dollars)		
Excess of capital cost allowance and exploration and development expenditures claimed for tax purposes over depletion, depreciation and amortization provided in the accounts	$ (1,351)	$ (4,600)	$ (1,325)
Non-capital loss carry-forward	(796)	—	(10,069)
Amounts expensed for tax purposes but capitalized in the accounts	1,853	38	1,940
Deferral of current taxes payable as a result of corporate reorganization	—	1,128	3,279
Other, net	294	(7)	—
	$ —	$ (3,441)	$ (6,175)

The Company and its Canadian subsidiaries have non-capital losses available for carry-forward of approximately $13.0 million of which $5.0 million and $8.0 million expire in 1990 and 1991, respectively. In addition, the Company has capital losses available for carry-forward of approximately $17.0 million. The Company's U.S. oil and gas subsidiaries have net operating losses available for carry-forward estimated to be approximately U.S. $18.0 million which losses begin to expire in 1992. The resulting income tax reductions will be included in earnings in the year realized.

The provision for income taxes differs from the amount that would have been computed by applying statutory income tax rates to earnings reported in the accounts. The principal reasons for this difference are as follows:

	1984	1983	1982
	(thousands of Canadian dollars)		
Loss from continuing operations before income taxes and extraordinary item	$ 37,799	$ 92,925	$ 48,518
Average statutory tax rate	49%	48%	47.8%
Computed "expected" income tax provision	$ (18,521)	$ (44,604)	$ (23,192)
Increase in income taxes resulting from			
Non-deductible royalties and other payments	5,460	4,411	4,811
Non-deductible depletion, depreciation and amortization	2,426	3,215	1,029
Non-deductible Petroleum and Gas Revenue Tax	2,261	1,409	1,767
Writedown of oil and gas properties	—	31,824	—
Non-taxable portion of writedown of other assets	1,003	573	—
Non-taxable portion of losses on disposal of assets	5,098	—	—
Loss on sale of United States oil and gas properties	—	1,632	—
Non-capital loss carry-forward	2,728	—	—
Net capital loss carry-forward	5,192	—	—
Losses of subsidiaries	—	2,069	12,602
Reassessment of income taxes	—	1,000	—
Taxable capital gain	—	—	1,740
	24,168	46,133	21,949
Decrease in income taxes resulting from			
Federal resource allowance	(4,970)	(3,414)	(3,872)
Alberta Royalty Tax Credit	(2,367)	(2,775)	(4,134)
Earnings of subsidiaries	(539)	—	—
Non-taxable amounts	(301)	—	—
Earned depletion allowance	(75)	—	(953)
Reassessment of income taxes	—	—	(426)
Other	—	—	(47)
	(8,252)	(6,189)	(9,432)
Actual income tax provision	$ (2,605)	$ (4,660)	$ (10,675)

The components of losses before income taxes between domestic and foreign categories together with related income taxes are set out below.

	1984		
	Canada	Foreign	Total
	(thousands of Canadian dollars)		
Loss from continuing operations before income taxes and extraordinary item	**$ 16,950**	**$ 20,849**	**$ 37,799**
Provision for income taxes			
Current	**$ (2,605)**	**$ —**	**$ (2,605)**
Deferred	**—**	**—**	**—**
	$ (2,605)	**$ —**	**$ (2,605)**

	1983		
	Canada	Foreign	Total
	(thousands of Canadian dollars)		
Loss from continuing operations before income taxes and extraordinary item	$ 85,561	$ 7,364	$ 92,925
Provision for income taxes			
Current	$ (1,219)	$ —	$ (1,219)
Deferred	(3,441)	—	(3,441)
	$ (4,660)	$ —	$ (4,660)

	1982		
	Canada	Foreign	Total
	(thousands of Canadian dollars)		
Loss from continuing operations before income taxes and extraordinary item	$ 19,501	$ 29,017	$ 48,518
Provision for income taxes			
Current	$ (4,500)	$ —	$ (4,500)
Deferred	(6,175)	—	(6,175)
	$ (10,675)	$ —	$ (10,675)

9. Discontinued operations

In 1984, the Company sold the operations of the Lift Systems International Division which manufactures pumpjacks, and Heritage Industries Ltd., a foundry operation, and recorded an extraordinary loss on disposal of these two operations of $1.0 million. The operating losses for the period prior to disposition are segregated from those of the Company's continuing operations and are summarized below. The Company also discontinued certain other operations in 1982.

	1984	1983	1982
	(thousands of Canadian dollars)		
Revenue	**$ 5,602**	$ 3,637	$ 8,794
Expenses			
Operating	**7,154**	3,948	10,904
General and administrative	**615**	1,753	2,043
Depreciation	**312**	460	1,444
	8,081	6,161	14,391
Loss from discontinued operations	**$ 2,479**	$ 2,524	$ 5,597

The net assets of discontinued operations are summarized as follows:

	1984	1983	1982
Working capital (deficiency)	(thousands of Canadian dollars)		
Accounts receivable	**$ 7**	$ 612	$ 1,053
Inventories	**—**	3,448	5,149
Other assets	**2**	298	232
Bank indebtedness	**—**	(170)	(1,056)
Accounts payable	**(152)**	(391)	(2,522)
	(143)	3,797	2,856
Property and equipment	**78**	1,871	4,185
Long term debt	**(24)**	(510)	(790)
	$ (89)	$ 5,158	$ 6,251

10. Share capital

a) Issued

	Number of Common Shares	Share Capital, $1 Par Value	Contributed Surplus
		(thousands of Canadian dollars)	
Balance at September 30, 1981	6,871,114	$ 6,871	$ 34,992
Cancelled	(11)	—	—
Balance at September 30, 1982	6,871,103	6,871	34,992
Shares issued			
Equity incentive program	91,250	91	226
Balance at September 30, 1983	6,962,353	6,962	35,218
Shares issued			
Equity incentive program	4,250	5	11
Balance at September 30, 1984	6,966,603	$ 6,967	$ 35,229

b) Share options and incentives

In 1982 the Board of Directors approved a new equity incentive program. Under the terms of the program 350,000 common shares were reserved for issue. A total of 314,000 options have been issued (173,000 to officers and 141,000 to other employees), 81,500 options have been cancelled, and 95,500 options have been exercised, leaving 137,000 options remaining to be exercised. The options are granted at a 15% discount from the market price at the time of the award if the closing price is under $5.00 and 10% if closing price is over $5.00. For officers and employees employed at November 8, 1982, all optioned shares are now exercisable at a price of $3.485 per share. For new employees, 50% of the options granted may be exercised one year after their award, with the balance exercisable after two years. The options expire three years from the date they were granted. There is a three-month probationary period prior to the granting of options to new employees.

When shares are issued, any excess of proceeds over the par value of those shares is credited to contributed surplus.

c) Shares reserved

The following common shares of the Company have been reserved:

	1984	1983	1982
For conversion of subordinated debentures	**1,581,028**	1,581,028	1,581,028
Under the incentive program	**254,500**	258,750	350,000
	1,835,528	1,839,778	1,931,028

11. Contingencies

The Civil Action brought by the Company against The Catawba Corporation ("Catawba") and several former officers and directors of the Company remains unresolved. The action is for fraud and illegality in causing the Company to enter into management agreements with Catawba and to pay Catawba U.S.$3.2 million as a purported settlement in lieu of granting Catawba an overriding royalty on the sale of certain North Sea assets in l975. The defendants are aligned into two groups. Separate but essentially similar settlement negotiations are being actively undertaken between the Company and each of the groups. The Company remains of the opinion that such negotiations are progressing fruitfully and the Company will not instigate any further Court proceedings.

On September 6, 1983, the Security Pacific National Bank (Trustee for Great Basins Petroleum Co. Liquidating Trust) brought suit against the Company based upon allegations that the Company breached a share sale agreement with Great Basins Petroleum Co. under which the Company was obligated to make an offer to purchase the unit interests of the limited partners of the 1971 and 1972 Great Basins Exploration and Development Programs, and seeking an order for specific performance and damages which the Plaintiff might sustain by reason of any action being brought against it by such limited partners. On October 7, 1983, the Company filed its Statement of Defence and since such time no developments have occurred in this action. Management is not able to determine the Company's exposure nor the likely outcome of this action.

By Order of the Court of Queen's Bench of Alberta entered November 5, 1984, the Court awarded to Mr. D. L. Hiebert, former President and Director of the Company, a judgment for damages in lieu of notice of termination of his contract of employment, and damages for his loss of the right to exercise a stock option in an aggregate amount of $0.2 million, together with his costs of the action. The claim brought by Mr. D. L. Hiebert jointly against Billy R. Delp, a Director of the Company, was dismissed. The Company has discharged in full its obligations under this judgment.

Any settlement resulting from the resolution of any of the contingencies referred to in this Note shall be included in earnings in the period in which such settlement occurs.

The Company has included in current liabilities an amount of $10.9 million representing its fifty per cent share of the liabilities in a real estate joint venture. The Company is jointly and severally liable for the remaining fifty per cent.

On September 15, 1983, ICG Frontier Exploration Ltd. ("ICG") and others commenced a civil action in the Court of Queen's Bench of Alberta against Sun Oil Company ("Sun") and others. ICG claims damages of $50.0 million for Sun's alleged disposition to the other defendants of interests in Alberta Crown petroleum and natural gas leases, which dispositions ICG claims included interests to which ICG was entitled. On November 27, 1984 the Company was first served in this action with an Amended Statement of Claim on the basis that the Company once held such interests as a party in a chain of dispositions from Sun to the other defendants. Management is of the opinion that the Company holds a meritorious defence to this action and that the Company's exposure is minimal.

12. Writedown of oil and gas properties

The carrying value of the Company's oil and gas properties is determined for each cost centre by an evaluation based on the estimated net present value of future cash flows from proved reserves, assuming constant pricing and a discount factor of 10%. Unproved properties are evaluated at the lower of cost and fair market value. As a result, the carrying value of assets in the cost centres were written down in 1983 by $66.3 million; (1982 - $23.8 million).

13. Sale of United States oil and gas properties

Effective January 1, 1983, the Company sold substantially all its United States oil and gas properties to three limited partnerships managed by ConVest Energy Corporation of Houston, Texas for proceeds of U.S. $16.2 million (Cdn. $19.9 million), resulting in a loss on disposal of $3.4 million. The Company retained its direct interest in the West Cameron gas property, located offshore Louisiana.

14. Differences between Canadian and United States generally accepted accounting principles

The accounting principles applied by the Company and generally accepted in Canada differ from those generally accepted in the United States as follows:

	1984	1983	1982
	(thousands of Canadian dollars)		
Loss before extraordinary items as reported	**$ 37,673**	$ 90,789	$ 43,440
Adjustments to conform to United States generally accepted accounting principles			
a) Foreign currency translation (gain) loss	**1,724**	(1,613)	182
b) Provision for loss from discontinued operations	**1,031**	—	3,646
Net loss	**$ 40,428**	$ 89,176	$ 47,268
Loss per share	**$ 5.80**	$ 12.92	$ 6.88

(a) The United States Financial Accounting Standard Board Statement No. 52 requires that long term debt payable in foreign currency be translated at the rate of exchange prevailing at the balance sheet date with the resulting translation gains and losses being included in earnings in the current period. In Canada these exchange gains and losses are deferred and amortized over the term of the related debt.

If the Company had adopted the provisions of Statement No. 52, long term debt would have remained at the stated amount, but the deferred foreign exchange loss of $1.7 million would have been included in expenses in the current year. The deficit would have increased by $293,000 (1983 - ($1,431,000)); 1982 - $182,000).

(b) United States generally accepted accounting principles require that any provision for loss from discontinued operations be included in operating results and not as an extraordinary item.

(c) United States generally accepted accounting principles require that the operating loan of $7.4 million be disclosed as a current liability. Long term debt would decrease to $167.7 million and the working capital deficiency would increase to $70.4 million.

15. Related party transactions

The law firm of Holland and Holland rendered legal services to the Company for fees of $62,000 (1983 -$101,000; 1982 - $92,000). Mr. J.W. Holland, Secretary and a Director of United Canso, is a partner in that law firm. Mr. Holland received no direct compensation from the Company in his capacity as Secretary.

The law firm of McInnes, Cooper and Robertson rendered legal services to the Company for fees of $3,000 (1983 -$23,000). Mr. G.B. Robertson, Assistant Secretary and a Director of United Canso, is a partner in that law firm. Mr. Robertson received no direct compensation from the Company in his capacity as Assistant Secretary.

16. Remuneration of directors

Aggregate remuneration paid during the year to directors of the Company in their capacity as directors amounted to $66,000 (1983 - $67,000; 1982 - $95,000).

17. Retirement plan

The Company has a non contributory pension plan which is in effect for all permanent employees following one year of employment. The Company contributed $146,000 (1983 - $139,000; 1982 - $121,000) to the pension plan during the year in accordance with actuarial requirements. At January 1, 1982, the date of the last actuarial review, the plan was fully funded.

18. Segmented information

The Company's principal business segment has been determined to be exploration for and development of crude oil and natural gas with operations primarily in Canada.

During 1983, the Company sold substantially all its United States crude oil and natural gas assets. The assets and related operating results have been included as a separate geographic segment for comparative purposes.

During 1984, the Company discontinued all oilfield manufacturing and service operations. The results from operations have been reclassified for 1983 and 1982 and disclosed separately (Note 9). In addition, the Company sold the majority of its Australian interests in exchange for marketable securities, which securities have been included with Canadian assets for 1984.

	1984	1983	1982
	(thousands of Canadian dollars)		
Revenue			
Canada	$ **40,642**	$ 31,264	$ 29,805
United States	**1,923**	2,017	8,978
	$ **42,565**	$ 33,281	$ 38,783
Operating loss (income)			
Canada	$ **(20,177)**	$ 55,147	$ (14,900)
United States	**(838)**	5,371	25,977
Other foreign	**18,130**	—	2,130
	(2,885)	60,518	13,207
Corporate and other			
Interest and other revenue	**(870)**	(544)	(820)
General and administrative	**3,626**	4,933	7,691
Interest on long term debt	**28,143**	27,326	28,440
Writedown of other assets	**9,731**	692	—
Income taxes	**(2,605)**	(4,660)	(10,675)
Loss from discontinued operations	**2,479**	2,524	5,597
Extraordinary item	**1,031**	—	3,646
Other	**54**	—	—
	41,589	30,271	33,880
Net loss	$ **38,704**	$ 90,789	$ 47,086
Identifiable assets			
Canada	$ **153,273**	$ 158,570	$ 228,016
United States	**2,267**	9,257	35,616
Australia and other	**—**	35,963	28,650
	$ **155,540**	$ 203,790	$ 292,282

Gulf Canada Limited, Esso Resources Limited and Shell Canada Limited purchase approximately 38%, 18% and 14% respectively of total crude oil produced by the Company in Canada. Approximately 39% of the Company's natural gas production in Canada is sold to a utility, Canadian Western Natural Gas Company Limited and 20% is sold to a transmission company, TransCanada PipeLines Limited.

19. Comparative figures

Certain prior years' figures including those related to discontinued operations have been reclassified to conform to the presentation adopted in fiscal 1984.

Supplementary Financial Information

Reporting the Effects of Changing Prices — Unaudited

Section 4510 of the Canadian Institute of Chartered Accountants ("CICA") Handbook requires that unaudited supplementary information be disclosed in the Company's financial statements reporting the effects of changing prices.

The requirements recognize the unique nature of oil and gas assets and recommend that a Company approximate a current cost measurement by applying appropriate specific price changes to the amounts capitalized in the historical cost financial statements. Management believes that such an arithmetic calculation would not be meaningful. Specific price indices applied to the original costs of oil and gas assets would not be representative of current cost of either purchasing or finding similar oil and gas reserves. The replacement of the Company's reserves at current cost is purely hypothetical and subject to considerable uncertainty.

Management believes the current cost of oil and gas properties may be estimated using the net present value of future expected cash flows from proved reserves. As the Company, has in each of the three years prior to 1984 written down the carrying value of the Company's oil and gas properties to the estimated net present value of future cash flows, the financial statements currently reflect an estimate of current cost. Also, the accompanying supplementary unaudited financial information relating to Oil and Gas Producing Activities discloses current cost information in addition to meeting the requirements of Section 4510 related to oil and gas reserve disclosures.

Oil and Gas Producing Activities — Unaudited

(Thousands of Canadian Dollars, except where indicated)

Information required to be disclosed in accordance with FASB Statement No. 69 "Disclosures About Oil and Gas Producing Activities" and CICA Handbook Section 4510 as it relates to oil and gas reserves is discussed below and further detailed in Tables 1 through 6 immediately following.

The reserve quantity and valuation estimates included in the following tables have been excerpted or based on reports of Company reservoir engineers for 1984 and 1982 and reports prepared by independent consulting engineers from McDaniel and Associates Consultants Ltd. in 1983.

Estimated quantities of total proved reserves of crude oil (including condensate and natural gas liquids) and natural gas are disclosed net after royalty. Proved reserves are estimated quantities of reserves which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Values were determined using current prices, increased only for fixed and determinable escalation provisions in contracts.

The increases in crude oil and NGL reserves and gas reserves are a result of revisions and additions primarily in Medicine Hat and Rowley in Alberta and Coleville and Hoosier in Saskatchewan.

Estimation of reserve quantities is based on sound geological and engineering principles. However, the results are estimates based on judgmental interpretation of reservoir data. They are subject to revision as additional information regarding producing fields and technology becomes available and as economic and operating conditions change. Actual cash flows will differ from future net cash flows presented in that:

(a) future cash flows will be derived not only from proved reserves but also from probable and potential reserves which may ultimately become proved;

(b) future, rather than current year costs and prices will apply; and

(c) economic, regulatory and operating conditions can change.

Because of these inherent limitations, the data shown below should not be construed as being the value of the Company's oil and gas producing activities.

Some of the amounts may not agree with amounts reported under similar headings presented elsewhere in this report due to categorization of costs by FASB Statement No. 69 and CICA Handbook Section 4510. United States reserve values have been converted to Canadian dollar equivalents at exchange rates in effect at the end of the respective reporting periods.

TABLE 1

Capitalized Costs Relating to Oil and Gas Producing Activities

September 30, 1984, 1983 and 1982

(thousands of Canadian dollars)

	1984	1983	1982
Unproved properties not being amortized	**$ —**	$ 32,737	$ 29,273
Producing oil and gas properties	**252,968**	249,347	295,924
Total capitalized costs	**252,968**	282,084	325,197
Less: Accumulated depletion, depreciation and amortization, and valuation allowances	**(125,175)**	(114,373)	(76,519)
Net capitalized costs	**$ 127,793**	$ 167,711	$ 248,678

TABLE 2

Costs Incurred In Property Acquisition, Exploration and Development Activities

Three Years Ended September 30, 1984

(thousands of Canadian dollars)

	1984				
	TOTAL	CANADA	U.S.A.	AUSTRALIA	OTHER
Exploration	**$ 762**	**$ (28)**	**$ —**	**$ 754**	**$ 36**
Development	**7,115**	**4,301**	**6**	**2,808**	**—**
	$ 7,877	**$ 4,273**	**$ 6**	**$ 3,562**	**$ 36**

	1983				
	TOTAL	CANADA	U.S.A.	AUSTRALIA	OTHER
Acquisition of proved properties	$ 835	$ —	$ 779	$ —	$ 56
Exploration	13,841	1,162	1,220	11,459	—
Development	9,570	6,668	460	2,442	—
	$ 24,246	$ 7,830	$ 2,459	$ 13,901	$ 56

	1982				
	TOTAL	CANADA	U.S.A.	AUSTRALIA	OTHER
Acquisition of proved properties	$ 1,316	$ 716	$ 600	$ —	$ —
Exploration	31,097	2,157	12,639	15,344	957
Development	3,818	3,054	764	—	—
	$ 36,231	$ 5,927	$ 14,003	$ 15,344	$ 957

TABLE 3

Results of Operations for Producing Activities

Three Years Ended September 30, 1984

(thousands of Canadian dollars)

	1984			
	TOTAL	CANADA	U.S.A.	OTHER
Revenue from oil and gas producing activities	$ 42,565	$ 40,642	$ 1,923	$ —
Production costs and taxes	11,052	10,782	270	—
Depletion, depreciation and amortization	10,498	9,683	815	—
Loss on sale of Australian subsidiary	18,130	—	—	18,130
Total expenses	39,680	20,465	1,085	18,130
Income (loss) before income taxes	2,885	20,177	838	(18,130)
Income taxes	2,605	2,605	—	—
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 5,490	$ 22,782	$ 838	$ (18,130)

	1983			
	TOTAL	CANADA	U.S.A.	OTHER
Revenue from oil and gas producing activities	$ 33,281	$ 31,018	$ 2,263	$ —
Production costs and taxes	8,223	7,536	687	—
Writedown of oil and gas properties	66,300	65,000	1,300	—
Depletion, depreciation and amortization	15,875	13,629	2,246	—
Loss on sale of U.S. oil and gas properties	3,401	—	3,401	—
Total expenses	93,799	86,165	7,634	—
Income (loss) before income taxes	(60,518)	(55,147)	(5,371)	—
Income taxes	4,660	4,660	—	—
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ (55,858)	$ (50,487)	$ (5,371)	$ —

	1982			
	TOTAL	CANADA	U.S.A.	OTHER
Revenue from oil and gas producing activities	$ 38,783	$ 28,204	$ 10,579	$ —
Production costs and taxes	11,317	7,538	3,779	—
Writedown of oil and gas properties	23,814	305	21,379	2,130
Depletion, depreciation and amortization	16,859	5,293	11,566	—
Total expenses	51,990	13,136	36,724	2,130
Income (loss) before income taxes	(13,207)	15,068	(26,145)	(2,130)
Income taxes	10,675	10,675	—	—
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ (2,532)	$ 25,743	$ (26,145)	$ (2,130)

TABLE 4

Reserve Quantity Information

Three Years ended September 30, 1984

	TOTAL		CANADA		U.S.A.	
	Crude Oil & NGL's (000's of barrels)	Gas (mmcf)	Crude Oil & NGL's (000's of barrels)	Gas (mmcf)	Crude Oil & NGL's (000's of barrels)	Gas (mmcf)
Proved reserves, September 30, 1981	5,307	288,215	4,590	285,035	717	3,180
Revisions to previous estimates	397	(17,131)	358	(17,208)	39	77
New field discoveries and extensions	40	1,618	24	742	16	876
Production	(576)	(9,248)	(442)	(8,664)	(134)	(584)
Sales of reserves	(68)	—	—	—	(68)	—
Proved reserves, September 30, 1982	5,100	263,454	4,530	259,905	570	3,549
Revisions to previous estimates	554	(107,018)	554	(107,018)	—	—
New field discoveries and extensions	257	102	257	102	—	—
Production	(494)	(6,870)	(480)	(6,557)	(14)	(313)
Sales of reserves	(556)	(2,417)	—	—	(556)	(2,417)
Proved reserves, September 30, 1983	4,861	147,251	4,861	146,432	—	819
Revisions to previous estimates	1,516	10,623	1,516	10,382	—	241
New field discoveries and extensions	363	—	363	—	—	—
Production	(547)	(9,199)	(547)	(8,645)	—	(554)
Sales of reserves	(15)	(991)	(15)	(991)	—	—
Proved reserves, September 30, 1984	6,178	147,684	6,178	147,178	—	506
Proved producing reserves, Beginning of year	4,851	107,935	4,851	107,116	—	819
End of year	6,150	120,175	6,150	119,669	—	506

TABLE 5

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

at September 30, 1984, 1983 and 1982

(thousands of Canadian dollars)

	1984			1983			1982		
	Total	**Canada**	**U.S.A.**	**Total**	**Canada**	**U.S.A.**	**Total**	**Canada**	**U.S.A.**
Future cash inflows	**$526,412**	**$524,453**	**$1,959**	$459,106	$456,700	$2,406	$1,271,096	$1,221,527	$49,569
Future costs									
Development	**9,288**	**9,288**	**—**	17,416	17,164	252	16,952	16,011	941
Production	**122,820**	**122,227**	**593**	155,104	154,369	735	271,270	250,947	20,323
Future net inflows before income taxes	**394,304**	**392,938**	**1,366**	286,586	285,167	1,419	982,874	954,569	28,305
Future income taxes	**115,535**	**115,535**	**—**	71,987	71,987	—	286,371	286,371	—
Future net cash flows	**278,769**	**277,403**	**1,366**	214,599	213,180	1,419	696,503	668,198	28,305
10% discount factor	**124,031**	**123,926**	**105**	114,745	114,614	131	507,951	500,781	7,170
Standardized measure of discounted net cash flows	**$154,738**	**$153,477**	**$1,261**	$99,854	$98,566	$1,288	$188,552	$167,417	$21,135

TABLE 6

Principal Sources of Change in the Standardized Measure of Discounted Future Net Cash Flows

Three Years Ended September 30, 1984

(thousands of Canadian dollars)

	1984	**1983**	**1982**
Sales of crude oil and natural gas produced, net of production costs	**$ (31,513)**	$ (25,058)	$ (27,466)
Net changes in prices and production costs	**18,957**	(156,658)	(12,218)
Extensions, discoveries and improved recovery, less related costs	**4,293**	413	13,192
Development costs incurred during the year which reduced future development costs	**4,303**	7,128	3,818
Revisions of previous quantity estimates	**39,462**	(100,940)	21,751
Accretion of discount	**14,474**	36,501	33,352
Net change in income taxes	**7,013**	152,706	1,195
Sales of reserves in place	**(2,105)**	(2,790)	(1,389)
Net change in the standardized measure of discounted future net cash flows	**54,884**	(88,698)	32,235
Standardized measure, beginning of year	**99,854**	188,552	156,317
Standardized measure, end of year	**$ 154,738**	$ 99,854	$ 188,552

Five-Year Statistical Review

	1984	1983*	1982*	1981*	1980*
REVENUE	**$ 43,435**	$ 33,825	$ 39,603	$ 33,172	$ 16,494
EXPENSES					
Operating	**11,052**	8,223	11,317	6,420	3,624
Depletion and depreciation including writedown of properties	**10,552**	82,175	40,673	11,070	9,331
General and administrative	**3,626**	4,933	7,691	4,337	4,114
Writedown of other assets	**9,731**	692	—	—	—
Interest on long term debt	**28,143**	27,326	28,440	5,952	—
Loss on sale of U.S. oil and gas properties	**—**	3,401	—	—	—
Loss on disposal of Australian subsidiary	**18,130**	—	—	—	—
Provision for income taxes	**(2,605)**	(4,660)	(10,675)	4,281	76
	78,629	122,090	77,446	32,060	17,145
Loss (earnings) from continuing operations before extraordinary item	**35,194**	88,265	37,843	(1,112)	651
Loss from discontinued operations	**2,479**	2,524	5,597	941	—
Loss (earnings) before extraordinary item	**37,673**	90,789	43,440	(171)	651
Extraordinary item	**1,031**	—	3,646	(25)	(174)
NET LOSS (EARNINGS)	**$ 38,704**	$ 90,789	$ 47,086	$ (196)	$ 477
Per Share: from continuing operations	**$ 5.05**	$ 12.78	$ 5.51	$ (0.17)	$ 0.10
: before extraordinary item	**$ 5.41**	$ 13.15	$ 6.32	$ (0.03)	$ 0.10
: after extraordinary item	**$ 5.56**	$ 13.15	$ 6.85	$ (0.03)	$ 0.07
FUNDS USED IN (GENERATED FROM) OPERATIONS	**(7)**	7,962	8,881	(15,479)	(10,037)
Per Share	**—**	1.15	1.29	(2.33)	(1.53)
CAPITAL EXPENDITURES					
Property and equipment	**8,299**	27,780	34,316	57,771	14,975
Investments	**1,051**	(8,131)	(317)	6,935	3,634
WORKING CAPITAL (DEFICIENCY)	**(63,041)**	(59,700)	(1,358)	(3,742)	23,740
Per Share	**(9.05)**	(8.65)	(0.20)	(0.56)	3.60
LONG TERM DEBT	**175,144**	181,640	238,316	190,975	—
SHAREHOLDERS' EQUITY (DEFICIENCY)	**(110,668)**	(71,980)	18,480	69,022	63,671
Per Share	**(15.89)**	(10.43)	3.19	10.05	9.66
TOTAL ASSETS	**155,540**	203,790	292,282	306,114	77,068
SHARES					
Average Number of Shares outstanding (000's)	**6,966**	6,904	6,871	6,645	6,574
Market price (Cdn $) — High	**4.75**	7.38	16.25	30.00	30.00
— Low	**1.50**	3.50	2.80	12.88	11.25
(U.S.$) — High	**3.81**	5.88	13.63	25.38	24.75
— Low	**1.13**	2.44	2.75	10.63	8.66

NOTES: (1) All dollar amounts are in thousands except per share figures.
(2) All per share amounts are calculated using number of shares outstanding, restated to reflect the 1981 stock dividend of 10%.

* Restated to reflect reclassifications of subsequently discontinued operations and other restatements to conform to the presentation adopted in fiscal 1984.

Corporate and Head Office

700, 777 - 8th Avenue S.W.,
Calgary, Alberta

Operating Subsidiaries

Canso Oil & Gas, Inc.

Canso Spain, Inc.

Great Basins Minerals Ltd.

Harbetta Pty. Limited

Imput Pty. Limited

Registrar and Transfer Agent

Guaranty Trust Company of Canada,
Calgary, Alberta

First Jersey National Bank,
Jersey City, New Jersey

United California Bank,
Los Angeles, California

Auditors

Clarkson Gordon,
Calgary, Alberta

Listings

Toronto, Montreal, Boston and Pacific Stock Exchanges (symbol UTC)

Officers	Title
Billy R. Delp	Chairman of the Board
John M. Taylor	President and Chief Executive Officer
Ronald B. Cyca	Vice President, Production
Robert G. Hillard	Treasurer
J. William Holland	Secretary
Colin Q. Winter	General Counsel and Assistant Secretary
Brian J. McManaman	Land Manager
George B. Robertson	Assistant Secretary
Sharon S. Harms	Controller

Board of Directors

Ronald B. Cyca Calgary Alberta	Vice President Production of the Company
Billy R. Delp Fort Worth, Texas	President, Nu-Way, Inc.
Robert G. Hillard Calgary, Alberta	Treasurer of the Company
William J. Holland Chicago, Illinois	Attorney and Vice President, Holland & Holland (Associated)
Dr. George H. Laycraft Vancouver, British Columbia	Executive Vice President, Chief Executive Officer and Director, Dusty Mac Mines Ltd. (N.P.L.)
Thomas A. O'Donnell San Pedro, California	Executive
George B. Robertson Halifax, Nova Scotia	Partner, McInnes, Cooper & Robertson, Lawyers
Robert W. St. Clair Fort Worth, Texas	Investor
John M. Taylor Calgary, Alberta	President and Chief Executive Officer of the Company

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