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UNITED
Canso
OIL & GAS LTD.

1982 Annual Report

Contents

METRIC CONVERSION

On January 1, 1979 the Canadian Petroleum Industry completed the conversion of measurement to the International Systems of Unit (SI). The following conversion table is intended to provide an understanding of the translation from traditional units to SI units.

Traditional Unit	SI Unit	Conversion Factor
Barrel	Cubic Metre (m^3)	1 Barrel = 0.159 Cubic Metres 1 Cubic Metre = 6.293 Barrels
Cubic Foot	Cubic Metre (m^3)	1 Cubic Foot = 0.0283 Cubic Metres 1 Cubic Metre = 35.31 Cubic Feet
Foot	Metre (m)	1 Foot = 0.305 Metre 1 Metre = 3.28 Feet
Miles	Kilometre (km)	1 Mile = 1.609 Kilometre 1 Kilometre = .621 Miles
Acre	Hectare (ha)	1 Acre = 0.405 Hectares 1 Hectare = 2.47 Acres

The annual meeting of the Shareholders will be held on Tuesday, March 8, 1983 at 9:30 a.m. in the Stephen Room, Calgary Convention Centre, Calgary, Alberta.

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 President, United Canso Oil & Gas Ltd., Box 2544 Stn. M, Calgary, Alberta, T2P 2M7.

Directors Report To The Shareholders

Fiscal 1982 was a difficult year for the petroleum industry and your Company in general. In the prior year, aggressive initiatives were made into American and Australian exploration, a diversification program was undertaken and most significantly, a major acquisition of Canadian natural gas reserves was consummated.

Many of these initiatives were made during a period of what was seen to be unlimited potential for the petroleum industry. The world economy then faltered and petroleum prices declined but interest rates remained at record high levels. This resulted in severe cash flow problems for your Company. This situation was aggravated by the fact that many of the ventures undertaken by United Canso, particularly in the United States, were not successful.

Much of 1982 was spent reducing exposure in the changed environment, lowering overhead, replacing management and otherwise putting our financial house in order. We were forced to retrench, to withdraw from our overly ambitious plans, and secure our asset base to ensure survival. We analyzed a number of possible asset sales and refinancings but did not find anything that was viable.

Fortunately, we have had some relief from the Canadian governments, particularly the Provinces of Alberta and Saskatchewan, and interest rates have declined significantly. Our largest transaction, the acquisition of the Canadian Great Basins companies now appears to hold promise for long term profitability.

We are not totally free of difficulties but some of the problems have been solved and we can now spend more time pursuing opportunities. We have solid assets and sound management. Most of our value is in Canadian natural gas about which we feel very confident. We have a substantial land position and excellent potential in some of our exploration activities in Canada and Australia. As a result of declining interest rates, new production coming on stream, higher prices for Canadian natural gas and lower government royalties, our financial position is expected to improve and we look forward to the future with optimism.

Our relationship with our principal lenders is excellent and we expect them to continue to support us. As interest rates decline, we will be locking in some of our debt for periods of three to five years. When equity markets improve, we will consider issuing common stock to increase our financial flexibility. In the meantime, we are pursuing various financing options in a difficult but improving market. Write offs this year reinforce the fact that we should concentrate our future effort on business and geographic areas about which we have experience and expertise, specifically Canadian and Australian oil and gas exploration and production.

Our appreciation goes to both our faithful stockholders and hard working staff for their efforts and continued interest in the success of your Company during these times.

In the following pages of our Annual Report, we describe our principal assets and potential out of which will come a stronger and more profitable company.

Respectfully submitted on behalf of the Board of Directors

Billy R. Delp

B. R. Delp

D. L. Hiebert

Exploration & Development

Canada

Bistcho Lake, Alberta

The Bistcho Lake area lies in the northwestern corner of the Province of Alberta. The area of interest that has been examined by United Canso encompasses approximately 3,800 square miles. To the southernmost extent of the study region, are the Shekilie and Zama fields, prolific oil and gas areas.

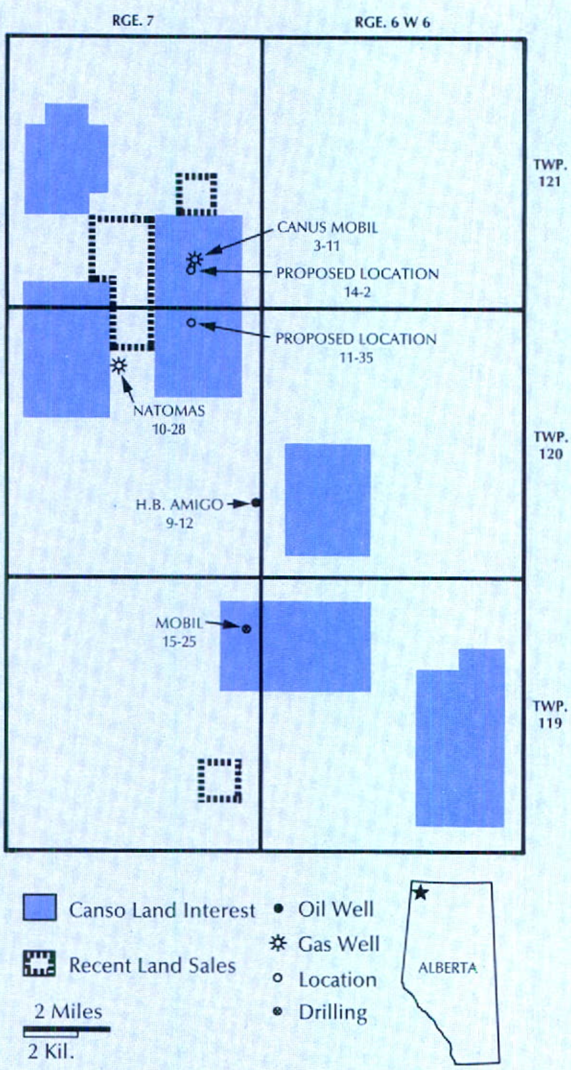
Recent exploration in Alberta has concentrated to a large extent in the Shekilie, Zama and Bistcho Lake areas. The target of exploration has been biohermal reefs containing large oil reserves. These reefs are characterized by a pinnacle form in the Bistcho Lake area with very high relief, thick pay zones, low water saturations, good porosity and permeability.

During 1982, United Canso undertook a seismic program on its lands to define the lucrative Keg River reefs. United Canso's effort has been rewarded by the identification of several anomalies within the area.

Recent land sale prices have exceeded $5,800 per acre for lands directly offsetting the Company's holdings in Township 121, Range 7, W6M and greatly enhance the potential for further exploration.

United Canso has had to curtail its exploration efforts and reduce staff over the last year. As our financial condition continues to improve we plan on increasing our efforts. Meanwhile, we have examined our land inventory and have developed several high quality prospects which we will be pursuing, hopefully this year.

We plan on concentrating our efforts in Western Canada where significant opportunities to develop cash flow in the near term exist and where our expertise lies.



Bistcho Lake Area, Alberta

Fenn-Big Valley-Rowley Area, Alberta

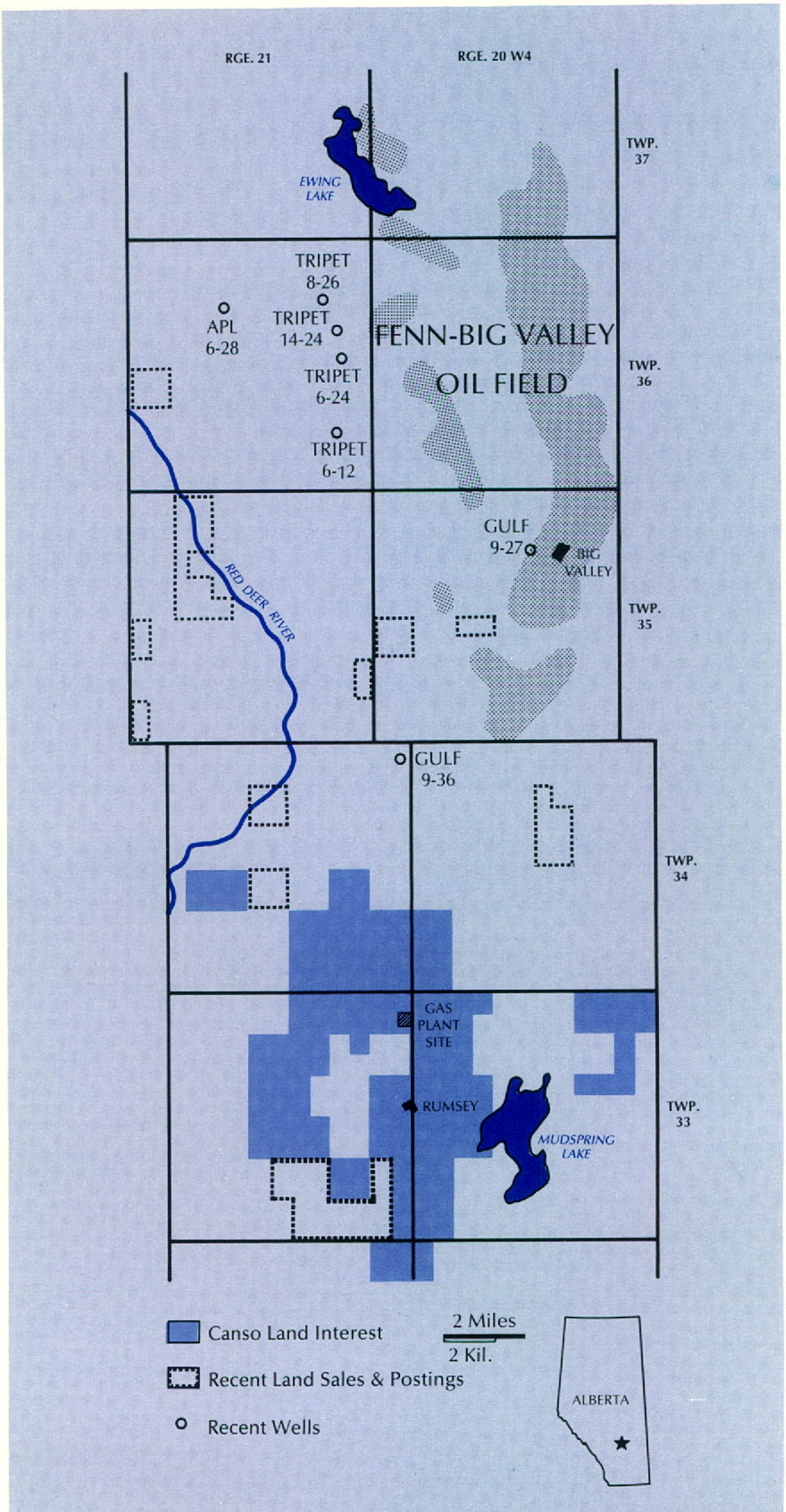
United Canso holds interests ranging from 15.46% to 100% in 23,840 gross acres (17,260 net) in the Rowley prospect area, approximately 65 miles northeast of Calgary, Alberta.

The area has potential for shallow Cretaceous, Viking, Glauconite and Basal Quartz gas and Basal Quartz oil production.

Recent discoveries of Devonian oil at Fenn-Big Valley such as the Gulf Rumsey 9-36-34-21 W4M well, just two miles north of United Canso's lands, have opened new possibilities of a Devonian reef oil play on our lands.

While the results of some recent wells in the area have not been publicly released, new discoveries of oil have resulted in a substantial increase in drilling activity and Crown Sale postings offsetting United Canso acreage. Some recent land sales have received bids of up to $1,750 per acre ($4,375 per hectare)

The Company has received numerous proposals by others who are intent on participating in the area by either farming in or joint venturing. These proposals are being held pending an intensive internal review of seismic data and a possible field seismic program.



Rowley Area, Alberta

Paddle River

United Canso currently has interests varying from 16.66% to 31.33% in 18,880 gross acres (5,173 net). In fiscal 1982, Canso participated in the drilling of three Mississippian tests. These tests resulted in two oil and gas discoveries and one gas discovery. A number of interesting locations remain to be drilled. The Operator is currently making plans to tie in the gas to sales.

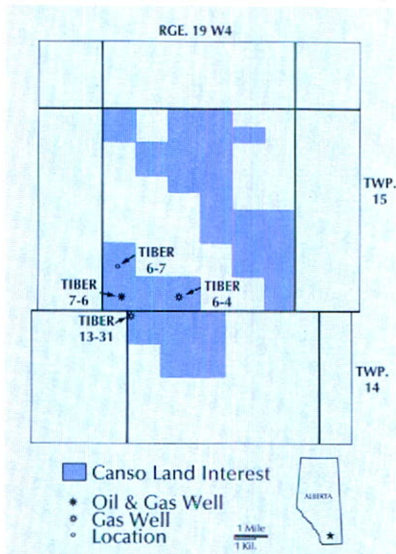
South Central Alberta

During 1982, we completed a four-section farmout in the Little Bow area in return for the drilling of two earning wells. The area has good potential for oil and gas pay in Lower Cretaceous sands. By year end three successful wells had been drilled on the farmout lands. Two are gas wells and the third is a dual oil and gas producer. These farmout lands were originally owned 100% by Canso and the drilling was subject to normal farmout terms. A fourth well has been proposed by the farmor to be drilled under the same terms.

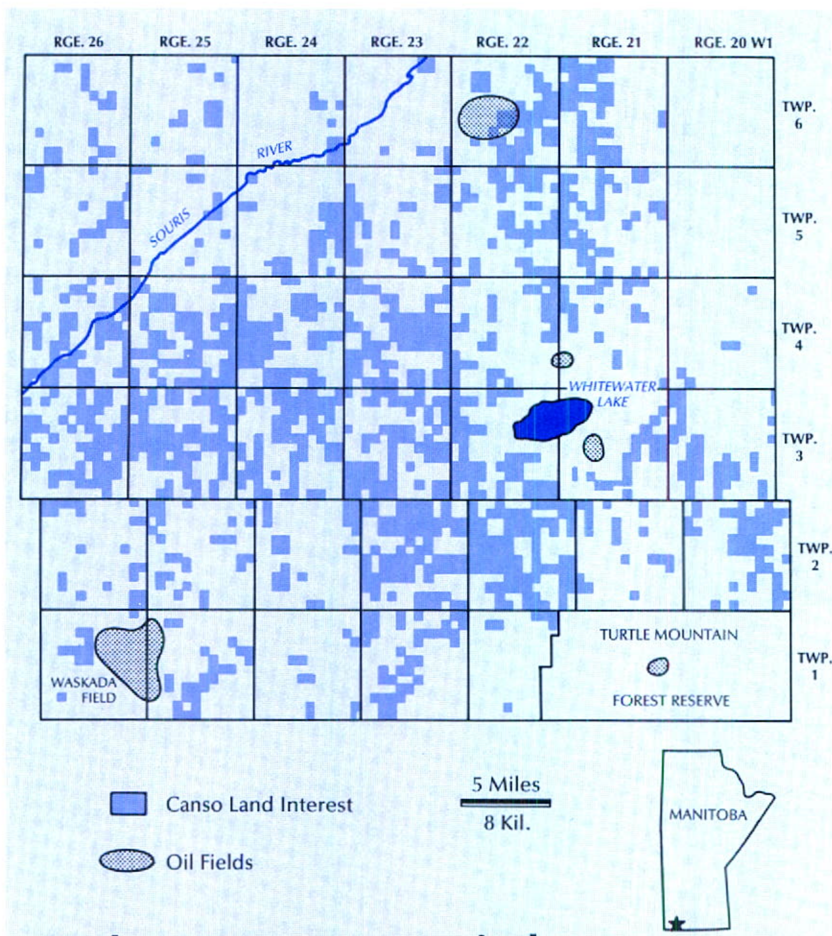
At Lomond we were successful in farming out two sections of Canso interest lands. The play involved Lower Cretaceous sands on which two wells have been drilled. One is a gas well and the second is a dual oil and gas well. This drilling again was under normal farmout terms on land in which Canso had original interest varying from 12% to 25% and in which the Company had interest in 12,626 gross acres (3,215 net).

Southwest Manitoba

At the beginning of the 1982 fiscal year, United Canso, through its acquisition of the Great Basins companies, held interests in approximately 180,000 gross acres in the Medora area of south-western Manitoba. As the acreage acquired through the corporate acquisition was widespread and subject to substantial expiries in 1982, United Canso actively sought potential farmees to explore and hold a maximum amount of prime acreage in the area. Prior to year end, the Company arranged an option agreement with a number of



Little Bow Area, Alberta



Medora Prospect, Manitoba

parties to jointly assume the role of exploring in the area, thereby eliminating the Company's requirement for participation in well costs and at the same time providing United Canso with a royalty interest in successful wells.

Fourteen wells have been drilled under the option agreement and it is anticipated that a total of 20 to 30 Mississippian tests will be drilled near the Waskada field.

Utikuma Lake

During 1982, United Canso acquired a 25% working interest in 2,240 gross acres (560 net) at Utikuma Lake in northern Alberta, 160 miles north of Edmonton. This area yields excellent oil production from the Devonian Gilwood and Keg River sands.

United Canso's 25% working interest position was farmed out in return for the drilling of a Keg River test. This test, BVX et al Nipisi 14-1-81-10W5M, has encountered Keg River oil production. United Canso has retained a GORR until payout with an option to convert to a 12.5% working interest after payout in the spacing unit. The farmor will also earn 50% of Canso's interest in the remainder of Section 1 and the SW 1/4 of Section 12-81-10 W5M. Further earning and option wells are planned.

International

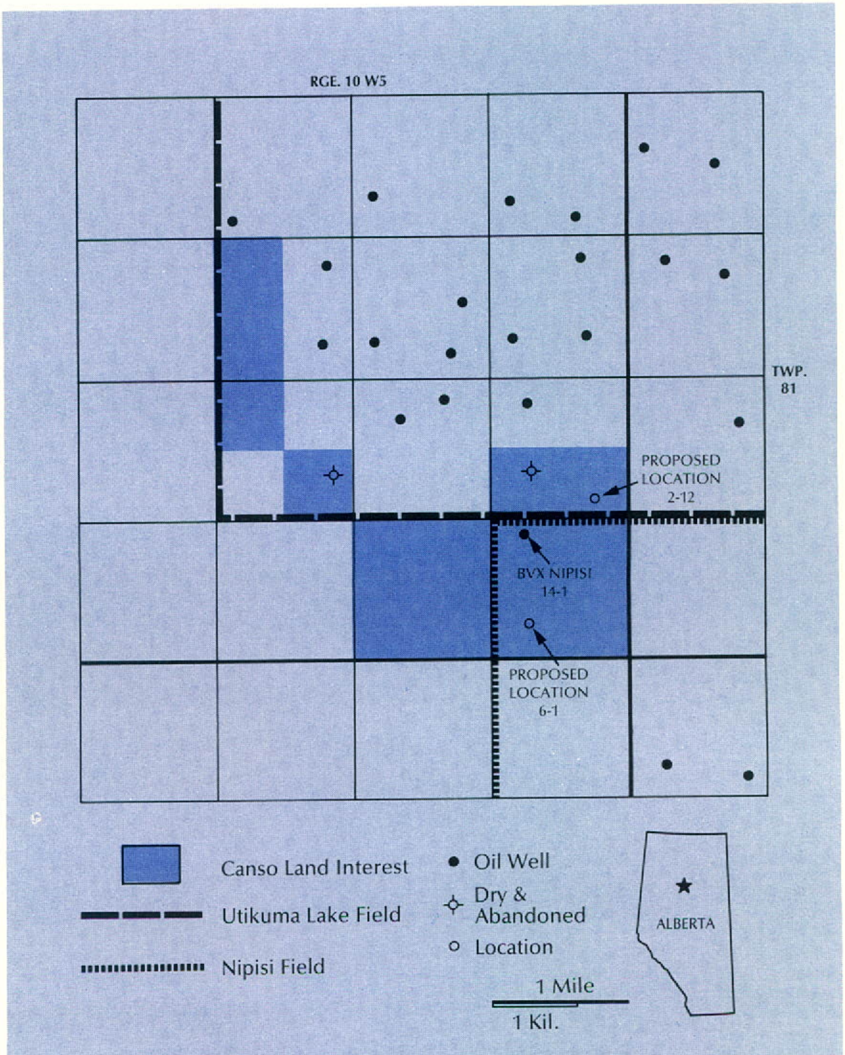
Due to our policy of fiscal restaint, United Canso is actively pursuing groups interested in acquiring Canso's position.

United Canso conducted approximately 185 miles of marine seismic in the area of a non-exclusive prospecting license in an area offshore from northern Sicily. The license involves an area of 155,600 acres. A number of attractive structural anomalies have been identified.

United Canso has a 14.4% working interest in the Delta E permit, located in Spain's offshore Mediterranean Basin. The northern part of this block remains prospective with several seismically defined anomalies.

Canso also maintains a 20% working interest in approximately 67,269 acres in the Tarragona C block offshore Spain.

An extension has been obtained from the Tunisian Government for the Kelibia permit in which Canso has a 15% working interest.



Utikuma Lake Area, Alberta

United States

In the United States, company activities have declined drastically. Several of the participation programs in which we were involved were dropped including the Woodbine and Hoen Exploration Programs. In these programs we had acquired valuable land but due to the economy, drilling plans did not materialize. We dropped out of the Westland Development Corp. Exploration Drilling Program on July 27, 1982. Work was proceeding with this program but our budgetory restraints did not permit us to continue.

Cotton Valley — Texas

Canso Inc. continued the drilling program in the Cotton Valley trend by the drilling of two wells in addition to the F.G. Cherry Gas Unit #1. These two wells Clara Glaspie Gas Unit #1 in Rusk County and Girtch Hawkins Gas Unit #1 in Marion County have been completed in the Cotton Valley formation. There are additional locations available for farmout in this area for which farmees are being actively pursued.

Deep Anadarko Basin — Oklahoma

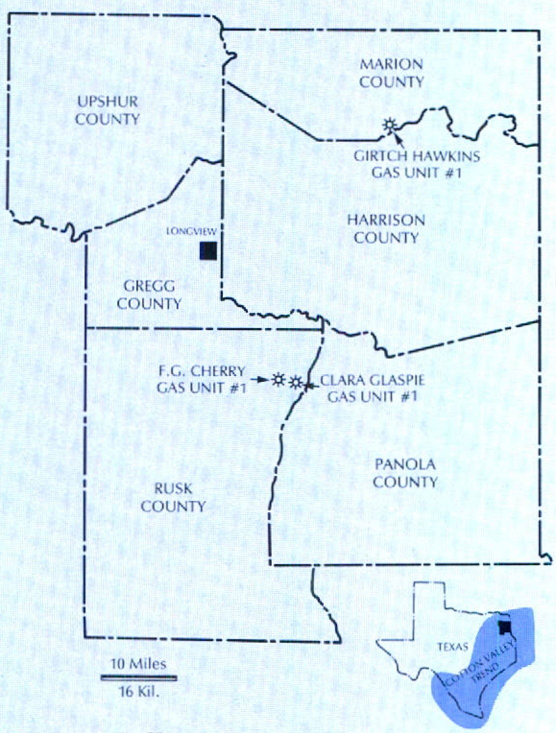
North Corn Prospect, Washita County, Oklahoma

During fiscal 1982, Canso Inc. participated in four additional wells to earn an interest in the Excalibur farmout lands in the Northwest Colony Field area of Washita County. Interests earned by the wells ranged from 0.05% to 0.80%. Three wells were completed as gas wells below 15,000 feet and one well was abandoned due to mechanical problems.

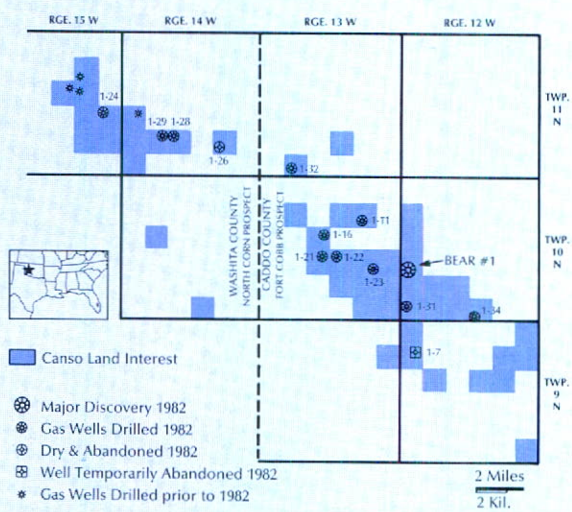
Fort Cobb Prospect, Caddo County, Oklahoma

Canso has earned an interest in an additional 10 wells as a result of drilling during the past year. Interest earned in these wells ranges from 0.48% to 12.48%, the latter for the Bear #1 well. Some of the wells are subject to a reversionary interest at payout.

The Bear #1 well was successfully completed and placed on stream as reported under production. Two additional wells, Oldtimer and Running Bear have attractive potential producing zones which are experiencing mechanical difficulties.



Cotton Valley, Texas



Anadarko Basin, Oklahoma

Australia

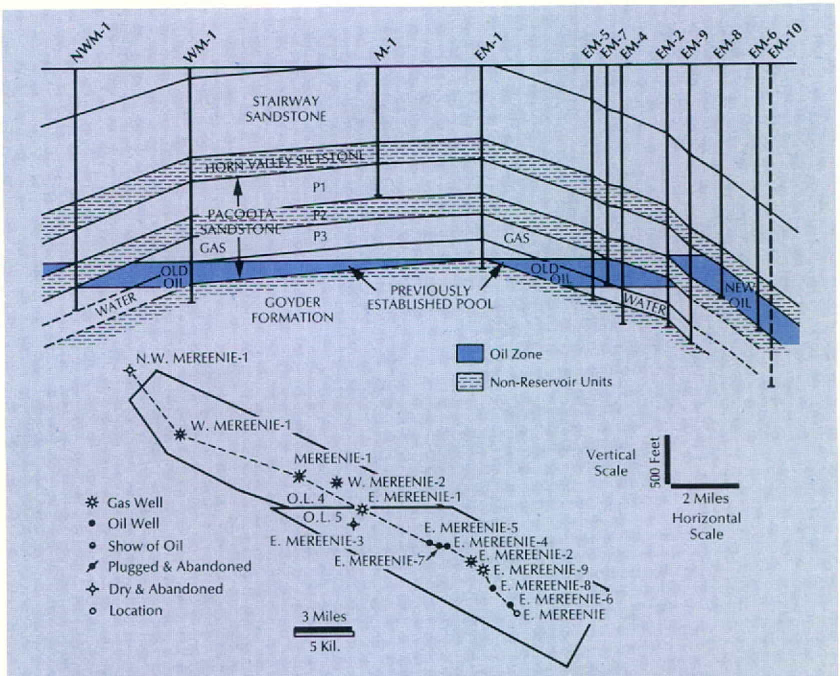
United Canso continues to be optimistic about Australia as an oil and gas province and also our position in that country. We have had difficulty in raising money by way of farmout or the sale of part of our equity, but we continue to pursue this objective. Through development of our existing reserves we expect a modest cash flow from our Australian ventures in 1983. The present value of the proven plus probable Australian reserves, discounted at 15% amounts to Can. $195 million at year end and we have an interest in 32 million gross acres.

Mereenie (Working Interest — Average 17.18%)

Under the conditions associated with the granting of the production leases, a twenty well appraisal drilling program in conjunction with a 115 mile detail seismic survey was commenced in early 1982. Five appraisal wells were drilled by November 1982 with the rig owned by the Mereenie joint venture parties. Four wells are oil wells and one is a gas well. The discovery of a "new" oil pool with the second appraisal well led to two follow-up wells with similar positive results. The significance of the discovery is that not only does the new find increase the reserve estimates for the Mereenie field but also the production from this pool is expected to receive full Import Parity Price which is estimated to be $A39.15 per barrel in 1983. Mereenie "old" oil receives Import Parity Price less $A3.00 per barrel levy. Production is expected to commence in 1983.

Palm Valley (Working Interest — 24.375%)

Natural gas from Palm Valley is now scheduled to come on stream in August 1983. The factors that led to this were the signing of a gas sales contract with the Northern Territory Electricity Commission and, in November 1982, the granting of a production lease by the Northern Territory Department of Mines and Energy followed by the award of a construction contract for the 95 mile pipeline from the Palm Valley field to Alice Springs. Up to 47 billion cubic feet of gas is contracted with delivery rates rising to 19 million cubic feet per day as the contract term progresses. Ultimate field reserves may be significantly increased if the matrix gas is found to supplement the gas deliverability from the fracture system in the reservoir. The price for initial gas deliveries is expected to be $A1.50 per thousand cubic feet with price escalation.



Mereenie Field, N.T., Australia

EP-114 Canning Basin

(3,962,378 Gross Acres)

A negotiated settlement between the consortium (of which Canso was a 40% partner) and the permit holder over the disputed farmin agreement was reached in March, 1982. As a consequence Canso now holds a 7% carried interest in the permit through an $A9,000,000 dollars of exploration expenditure. It is anticipated that this expenditure is to be completed early in 1983, at which time the Company has the option to convert to a 7% working interest.

The general level of industry confidence in the area as a future oil province is demonstrated by the intense level of seismic and drilling activities on adjacent permits within the last two years. The most publicized of these was the Blina oil discovery, 25 miles to the east.

OP-175, OP-178 Exploration Areas

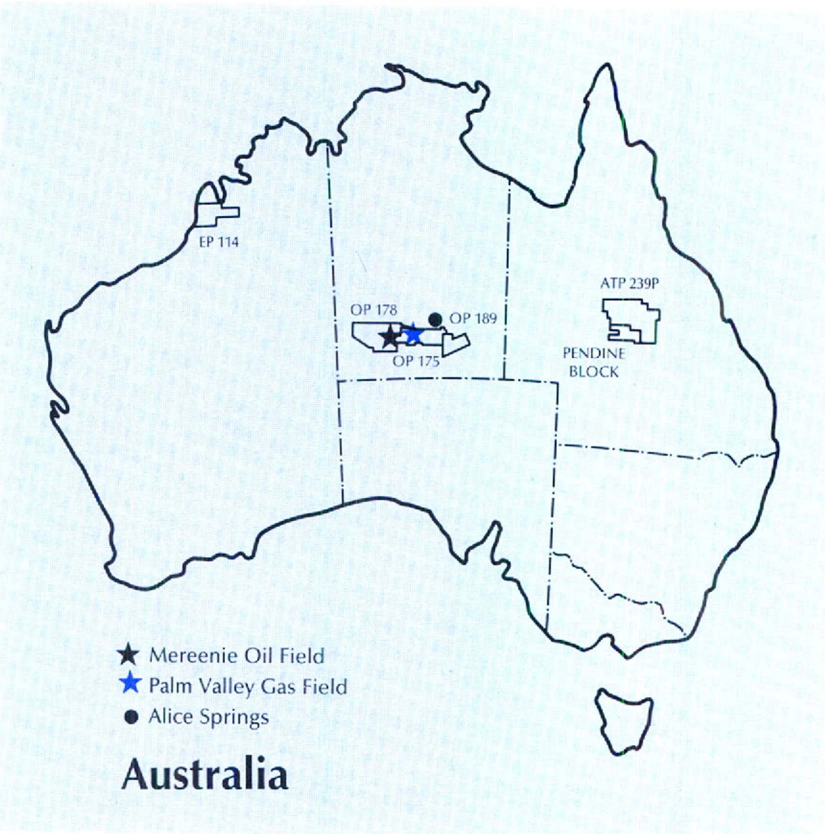
Canso gave notice of its withdrawal from the Amadeus Exploration Program on March 15th, 1982 but will still retain carried interests in the exploration areas of OP-175 and OP-178 through our respective 40% and 30% share-holdings in United Canso Oil & Gas Co. (N.T.) Pty. Ltd., and Magellan Petroleum (N.T.) Pty. Ltd.

Undandita, the fifth well of the 10 well Amadeus program is currently drilling. Two previous wells, Dingo No. 1 and West Walker No. 1 have been completed as potential gas producers. Each reported flows of over 1 million cubic feet per day. Mt. Winter, the fourth well in the program was abandoned.

During May 1982 the N.T. Government granted a renewal of OP-175 for an additional five year period. Under the terms of this renewal 50% of the permit lands were relinquished back to the Crown.

ATP 239P - Queensland

Canso has acquired all of the shares of Highwal Oil & Gas Pty. Ltd. This acquisition will provide the Company with a 10% working interest in all of the lands within ATP 239P (16,476,800 acres). Canso may earn an additional 54% in the Webb, Buchanan and Galilee Blocks (10,440,160 acres) by conducting 2,800 miles of seismic and drilling 4 wells.



Land

United Canso is fortunate to have a large land inventory for a company of its size. We are systematically reviewing our land position with a view to upgrading geological interpretations as well as protecting ourselves against expiries. As our financial position improves, we plan on judiciously adding to our land picture.

Canada

In Canada, the Land Department has focused on the consolidation of United Canso acreage holdings with those of its Canadian subsidiaries to facilitate the creation of exploration programs, farmout proposals and to encourage drilling by others.

Concentration on the two-fold objective of reduced long term capital commitment and increased cash flow has resulted in over one hundred and seventy approaches being made to third parties and the consummation of seventeen farmouts, options, pooling agreements and acreage sales within the last seven months of the 1982 fiscal year affecting some 190,000 gross acres.

Future plans include still further increases in farmout, option and sale activity utilizing the Company's acreage inventories to attract third party investment in exploratory and development plays.

We currently have a significant land picture in three very exciting and promising land plays in Canada, the Fenn-Big Valley-Rowley and the Bistcho areas in Alberta and the very active Medora area in Southwest Manitoba.

U.S.A.

In the U.S.A. we have made several attempts to farmout and sell acreage but due to the very restrained market in the U.S. we were only able to sell our 10% interest in Montana to our partner for U.S.$300,000. Farmout deals and brochures are prepared and being actively pursued.

Land Holdings

	As of September 30, 1982			
	Gross Hectares	Net Hectares	Gross Acres	Net Acres
OIL & GAS				
Yukon & N.W.T.	1,289	891	3,185	2,202 (1)
B.C.	54,568	7,560	134,836	18,680
Alberta	381,164	113,415	941,841	280,244
Saskatchewan	70,009	22,650	172,991	55,968
Manitoba	77,150	19,359	190,635	47,835
CANADA	584,180	163,875	1,443,488	404,929
UNITED STATES	113,811	25,019	281,223	61,822(2)
AUSTRALIA	13,010,359	2,027,049	32,148,159	5,008,769
EUROPE	227,225	18,122	561,464	44,780
TOTAL OIL & GAS	13,935,575	2,234,065	34,434,334	5,520,300
MINERALS (Canada)	8,671	2,972	21,425	7,343
GRAND TOTAL	13,944,246	2,237,037	34,455,759	5,527,643

(1) As the result of Bill C-48, the tenure of dispositions held by the Company in the Northwest Territories and Yukon is in question. Applications for provisional leases have been made.

(2) These acreage figures do not include Alaskan acreage of 722,517 gross (180,629 net) due to ongoing appeals concerning the filings.

Production

United Canso has substantial reserves of oil and natural gas supporting a long term production capacity. The North American reserves have a current value of $496,000,000 discounted at 15%. As the reserves are produced and prices, particularly those for gas, increase, our annual net revenue will increase substantially giving us the ability to service debt and also to embark upon new programs. Revenue from North American oil and gas operations is predicted to grow from $39,300,000 in 1983 to $69,600,000 in 1988 and to $79,900,000 in 1992.

Crude Oil and Natural Gas Liquids

Canada

In fiscal 1982, gross oil and natural gas liquids production from your Company's Canadian properties averaged 1966 barrels per day, down 5% from 1981, as most properties continued on a normal decline. New drilling during the past year added approximately 40 barrels per day of increased production. However, because of more favourable royalty treatment, particularly in Saskatchewan, net production has increased from 1,180 barrels per day in 1981 to 1,212 barrels per day in 1982.

United States

The average production rate from the Company's United States properties in fiscal 1982 was 463 gross barrels per day (367 net), up 29% from 1981. The increased production this year is due to a full year of production from J.E. Carter Energy Inc. which averaged 142 BOPD gross.

Major declines were experienced in the Powder River Basin of Wyoming where the Indian Creek Field production rate was reduced to approximately one-third of its capacity by the regulatory agencies until secondary recovery is instituted. The production rate from the Geritz Murphy well in Utah has also declined from the presently completed interval; it is anticipated that this well will be recompleted in additional pay intervals to restore productivity. Four oil wells brought on production during the year accounted for 30 barrels per day gross production.

The waterflood feasibility study of the Shannon formation in the Indian Creek Field in Wyoming has been completed. The results of the study were extremely favourable and the participating parties have agreed to the formation of a Unit to facilitate secondary recovery. The Company's interest in the Indian Creek Unit will be 19.5% and it is anticipated that water injection will commence by July 1983. By year end 1983 the production rate from this field will be restored to 130 barrels per day from its current rate of 23 barrels per day as a result of water injection.

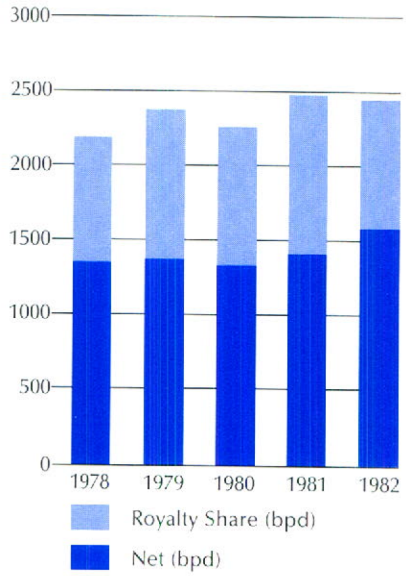
Natural Gas

Canada

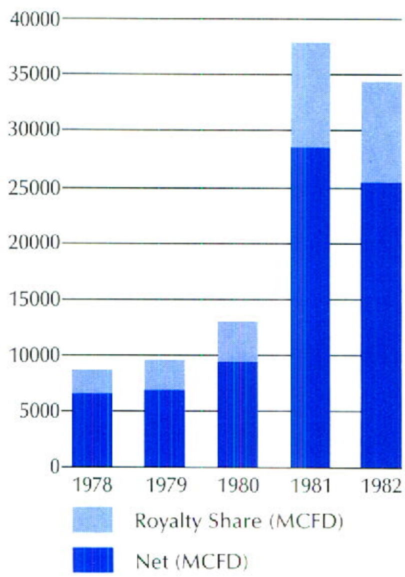
Natural gas sales from the Company's properties in Canada during fiscal 1982 decreased by approximately 3% to average 32.1 MMCFD gross. The net gas sales volumes after royalty averaged 23.7 MMCFD in fiscal 1982 compared to 25 MMCFD in 1981.

In July of 1982 the Markerville Gas Unit came on production resulting in 136 MCFD of gross gas sales to the Company. In the Little Bow area the Company has recompleted an oil well which had essentially watered out to a dual gas producing well. The gas from this well is contracted to Pan Alberta and facilities are currently being installed to place this 100% well on stream. It is anticipated that the gas

Production of Crude Oil & NGL's
(Daily Average)
Barrels per day (BOPD)



Natural Gas Sales
(Daily Average)
Thousands of cubic feet per day (MCFD)



sales from this well will average 0.6 MMCFD.

There will be a significant delay in bringing the Rowley project, in which the Company has a 75% working interest, on stream as a result of the pipeline not being in place to take delivery of the gas. The dehydration and compression facilities for this project are essentially complete and it was anticipated that this project would be on stream by November 1, 1982. It is now expected that it will not be on stream until mid 1983 at which time it is believed that the pipeline facilities will be complete. The major problem being encountered by the pipeline company at this time is obtaining surface owners' approval for the installation of the required pipeline. The Company share of gas sales from the Rowley project when it goes on stream will be approximately 5 MMCFD.

During the year TransCanada PipeLines proposed to the industry that it would restore the minimum contract obligation in the current allocation agreements in effect for the contract years 1980/81 and 1981/82 from 80% to 100% of the daily contract quantity. In return for this restoration of the contract obligation for the two contract years, the future obligation would be reduced to 60% of the daily contract quantity. In addition, TransCanada would assign its previously incurred take-or-pay payments as well as future take-or-pay obligations to the end of 1981/82 contract year to Topgas (a consortium of banks). The Company signed the Topgas Agreement which resulted in take or pay payments being received for the additional volumes in the 80/81 contract year of approximately $1,700,000. It is anticipated that an additional $3,000,000 take or pay payment will be received for the full contract quantity for the 81/82 contract year. The agreement that was signed this year with TransCanada PipeLines and Topgas provided also for the recovery of all prepaid gas that was incurred to the end of the 1982 contract year at a rate of approximately 10% per annum commencing November 1, 1984.

United States

The Company's gross gas sales from its U.S. properties declined from 3.5 MMCFD in fiscal 1981 to 2.1 MMCFD in 1982. The net sales rates to the Company after royalties were 2.9 MMCFD and 1.6 MMCFD respectively for 1981 and 1982.

Major declines in gas sales were from the West Cameron Blocks in offshore Louisiana where water production problems continue to reduce the productivity from this offshore platform.

A total of 10 wells in the Anadarko Basin in Oklahoma were brought on stream during the past fiscal year as a result of negotiating gas purchase contracts with a total of 4 different purchasers in the area. The sales from these wells will offset the decline experienced in West Cameron in the immediate future. Of the 10 wells in the Anadarko Basin that were brought on stream, 9 wells produce from below 15,000 ft. and thus are eligible for price deregulation. The deep gas prices that have been negotiated range from $6.00/MCF to $8.00/MCF varying with the purchaser involved.

The most significant well placed on stream was the Bear #1 well which went on stream July 22, 1982 and following a fracture treatment was producing at a rate of approximately 8 MMCFD at year end; your Company has a 12.48% working interest in this well before payout.

In the Cotton Valley trend of East Texas the Company has drilled and cased three wells to date; the wells are in various stages of completion at year end. The Company has a 100% working interest before payout in all three wells. The first well drilled in the program, F. G. Cherry Gas Unit #1 has been completed and on September 29, 1982 was given a mass fracture treatment in order to stimulate production. This well was tied in and subsequently produced 2.0 MMCFD of sales gas.

This well is under contract to a gas purchaser at the maximum price under Section 107, "tight gas pricing", and thus will receive a price in excess of U.S. $6.20/MCF including BTU adjustment and severance tax allowance.

The second well drilled in the program, Clara Glaspie Gas Unit #1, has been completed and is currently awaiting pipeline tie-in in order that it may be placed on stream. The gas purchase contract for this well is identical to that for the F. G. Cherry Gas Unit #1 well.

The third well drilled in the program, Girtch Hawkins Gas Unit #1 in Marion County, has been completed in the Bossier sand and briefly production tested. It is anticipated that the Lower Cotton Valley formation will be completed in the near future.

Reserves

The Company's reserves were evaluated this year by Company staff and a developed computer system with the exception of the Australian evaluation prepared by an independent consultant. The in-house procedure has proven to be cost effective and has allowed reserve evaluations to be updated instantaneously and continually. To better control reserve development, a new reserve category was introduced this year; *proven non-producing*. This category compliments the *proven producing* and *probable* reserve definitions.

Crude Oil & NGL

(thousands of Barrels)

	CANADA			UNITED STATES			AUSTRALIA		TOTAL	
	Proven Producing	Proven Non Producing	Probable	Proven Producing	Proven Non Producing	Probable	Proven Non Producing	Probable	Proven	Probable
At Sept. 30, 1981	6,907	N/A	1,733	949	N/A	184	2,718	2,559	10,574	4,476
Added by Drilling	27	14	—	18	15	47	—	—	74	47
Revision of Prior Est.	(259)	97	(340)	(37)	—	(53)	2,525	3,337	2,326	2,944
Production	697	—	—	154	—	—	—	—	851	—
At Sept. 30, 1982	5,978	111	1,393	776	15	178	5,243	5,896	12,123	7,467

Natural Gas

(millions of cubic feet)

	CANADA			UNITED STATES			AUSTRALIA		TOTAL	
	Proven Producing	Proven Non Producing	Probable	Proven Producing	Proven Non Producing	Probable	Proven Non Producing	Probable	Proven	Probable
At Sept. 30, 1981	372,155	N/A	27,652	3,971	N/A	2,745	85,700	42,000	461,826	72,397
Added by Drilling	—	601	—	856	96	2,799	—	—	1,553	2,799
Revisions of Prior Est.	(133,657)	98,937	18,609	875	—	(2,689)	(38,088)	254	(71,933)	16,174
Production	12,374	—	—	1,189	—	—	—	—	13,563	—
At Sept. 30, 1982	226,124	99,538	46,261	4,513	96	2,855	47,612	42,254	377,883	91,370

The definition of proven and probable reserves remains unchanged. The net reserves are *before royalty, taxes or burdens.*

Proven producing reserves are those established by existing production which to a high degree of certainty are recoverable under present production methods and current operating condition.

Proven non-producing reserves are those established by adequate test on existing wells or those beneath undeveloped tracts offsetting producing wells where geological control ensures their presence but are not currently on production.

Probable reserves are those estimates in zones behind pipe in existing wells or beneath undeveloped tracts where geological and reservoir data suggests the presence of these reserves but is insufficient to provide certainty or reserves considered to be recoverable due to the effects of a future institution of any form of enhanced recovery but no firm capital commitment has been made. Probable are also those reserves which are considered recoverable as a result of more favourable performance than that deemed proven at this time.

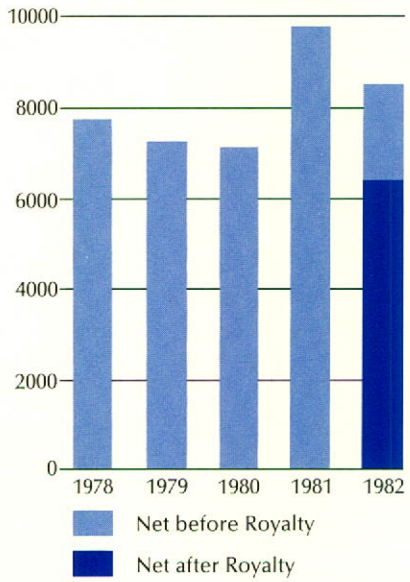
To illustrate the value of the above reserves, cash flow forecasts were prepared using the price forecasts shown below and were then discounted to reflect current value.

The world oil price was forecast to increase 5% per annum until 1985 and at 10% per annum after 1986.

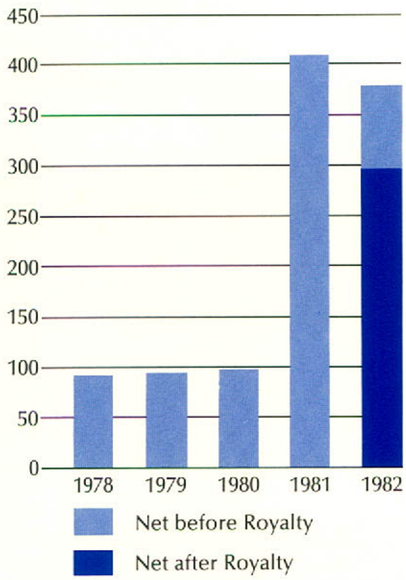
In Canada the gas price was escalated as per the pricing agreement between the Federal and Alberta governments which is in effect until 1986 and thereafter at 10% per annum. The price for conventional old oil was escalated as provided in the afore-referenced agreement until it reached 75% of the world oil price; it was assumed that this would occur in July 1983. Thereafter, it was forecast that the price would increase at 10% per annum.

In the United States it was assumed that the crude oil price would be the same as the world oil price. It was assumed that the gas price for deregulated deep gas in the United States would be in a "market-out" condition. It was further assumed that in fiscal 1983 all gas prices would remain at the level in effect at October 1, 1982. Thereafter the price was escalated at 10% per annum.

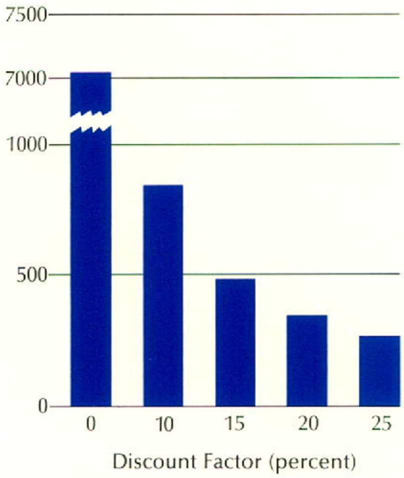
North America
Reserves of Crude Oil and NGL's
(Proven Plus Probable)
Thousands of barrels



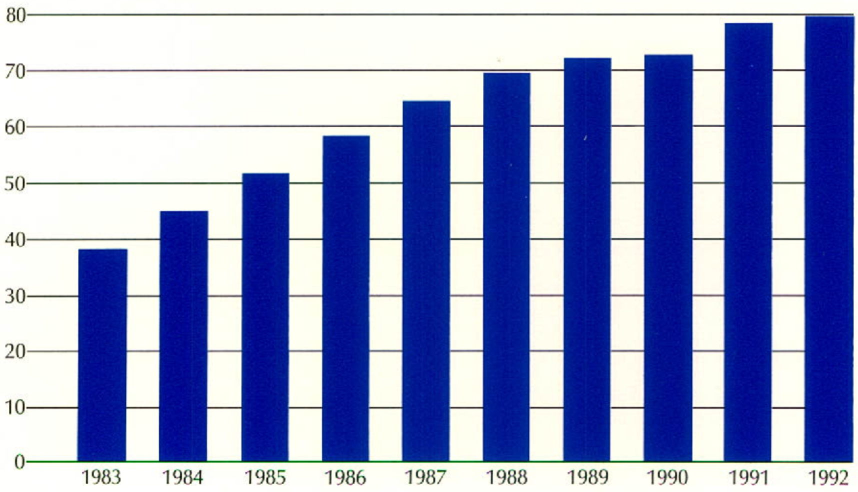
North America
Reserves of Natural Gas
(Proven plus Probable)
Billions of cubic feet (BCF)



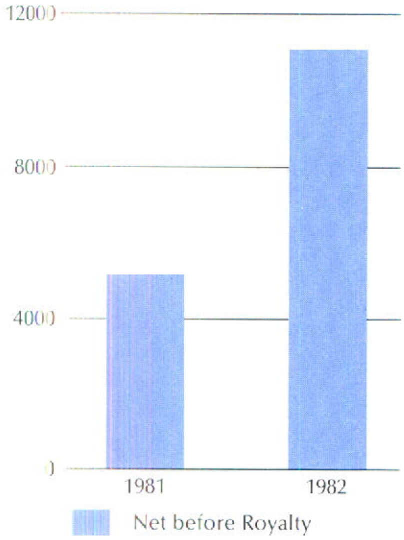
Present Worth of Cash Flow from North American Oil and Gas Operations
Proven Plus Probable Reserves
(before income tax)
(millions of Canadian Dollars)



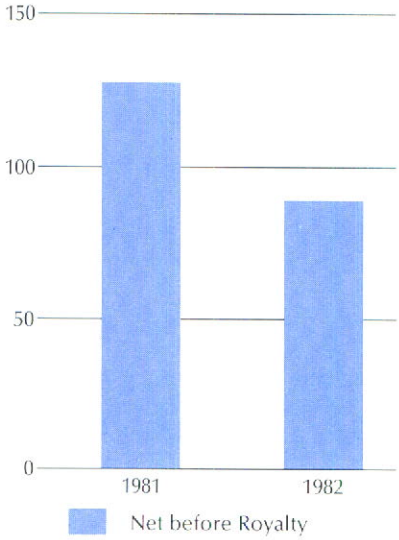
Oil and Gas Operations — North America
Cash Flow Projection (before income tax)
from Proven and Probable Reserves (See definition)
Millions of Dollars



Australia
Reserves of Crude Oil and NGL's
(Proven Plus Probable)
Thousands of barrels

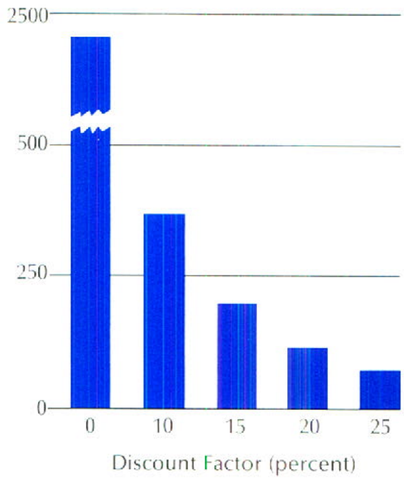


Australia
Reserves of Natural Gas
(Proven plus Probable)
Billions of cubic feet

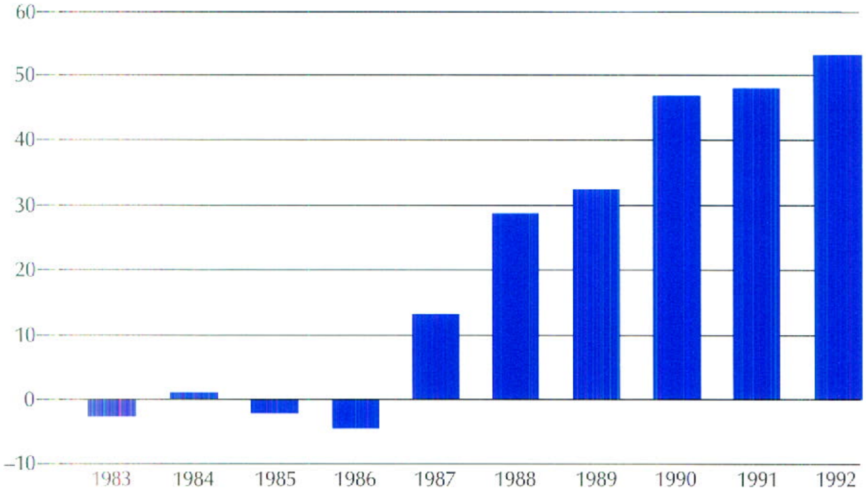


Present Worth of Cash Flow from Australian Oil and Gas Operations
Proven Plus Probable Reserves
(before income tax)

(millions of Canadian Dollars)



Oil and Gas Operations — Australia
Cash Flow (before income taxes)
from Proven and Probable Reserves (See definition)
Millions of Dollars



Drilling

United Canso participated in 88 wells during the past fiscal year of which 49 wells were productive for a success rate of 55%. At year end one well was drilling.

	1982							
	Oil		Gas		Dry		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploratory								
Canada	3	0.38	4	0.26	11	2.23	18	2.87
U.S.A.	5	1.69	18	2.61	24	1.02	47	5.32
Spain	—	—	—	—	—	—	—	—
Australia	—	—	2	0.53	2	0.47	4	0.99
Colombia	—	—	—	—	—	—	—	—
SUB-TOTAL	8	2.07	24	3.40	37	3.71	69	9.18
Development								
Canada	2	1.03	9	1.67	—	—	11	2.70
U.S.A.	2	0.25	—	—	2	0.10	4	0.35
Australia	4	0.60	—	—	—	—	4	0.60
SUB-TOTAL	8	1.88	9	1.67	2	0.10	19	3.65
TOTAL	16	3.95	33	5.07	39	3.81	88	12.83

	1981							
	Oil		Gas		Dry		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploratory								
Canada	3	0.2	11	2.0	11	4.8	25	7.0
U.S.A.	13	5.8	4	1.2	7	0.3	24	7.3
Spain	—	—	—	—	1	0.1	1	0.1
Australia	—	—	—	—	1	0.3	1	0.3
Colombia	—	—	—	—	1	0.3	1	0.3
SUB-TOTAL	16	6.0	15	3.2	21	5.8	52	15.0
Development								
Canada	—	—	21	15.5	4	2.1	25	17.6
U.S.A.	9	4.1	—	—	2	0.9	11	5.0
Australia	—	—	—	—	—	—	—	—
SUB-TOTAL	9	4.1	21	15.5	6	3.0	36	22.6
TOTAL	25	10.1	36	18.7	27	8.8	88	37.6

Industrial

The industrial division of United Canso was created in 1981 to provide services to the oil industry through three diversified wholly owned subsidiaries.

The three organizations are: Lift Systems International, a division of United Canso which manufactures pump jacks for oil wells and markets them in Canada and the U.S.A. The second entity is Heritage Industries Ltd. which operates a foundry in Winkler, Manitoba. The foundry casts parts for the L.S.I. pump jacks and for general sales primarily to the agricultural machinery manufacturing industry. The third entity is McCullough Ditching and Welding Ltd. and its subsidiary Burl Construction Ltd. who contract pipeline and plant construction for the oil and gas industry.

The downturn in the oil industry and the economy has had an adverse effect on this group of companies which depend on continued oilfield activity for their livelihood.

We are reviewing our involvement in this Division and are actively looking at available alternatives. In the meantime we are improving the management and operations of the companies at relatively modest cost to United Canso.

Financial

Management Discussion & Analysis of Financial Condition & Results of Operations

Results of Operations

United Canso experienced a net loss of $47.1 million or $6.85 per share during the 1982 fiscal year compared with net earnings of $196,000 or $0.03 per share in 1981. Reference should be made to Note 15 to the Consolidated Financial Statements in which information including operating income, revenues and assets by industry segments and geographic areas is provided.

a) Continuing operations

Consolidated revenue increased by 10% to $44.1 million in 1982 over 1981. Crude oil revenue of $16.1 million was higher by 50% in 1982 due to Canadian gross price increases of $4.50 per barrel during the year and the inclusion of the oil revenue of Carter Energy, acquired in August, 1981. Natural gas revenue increased 36% to $22.7 million in 1982 reflecting increased sales volumes of 12.5 billion cubic feet (bcf) versus 10.7 bcf in 1981. This increase arises from the inclusion of a full years production from the Great Basins properties, versus only eight months in 1981, reduced Alberta crown royalties from April 1, 1982 and Canadian gross price increases of 50 cents per thousand cubic feet in 1982. Revenue from the industrial division declined 33% to $4.5 million due to the downturn in Canadian oil and gas activity and the economic recession. Interest income declined to $455,000 in 1982 from $5.5 million in the prior year as all surplus funds were utilized in the acquisition of Great Basins on September 1, 1981.

Oil and gas operating expenses in 1982 of $7.3 million were up 63% over 1981 expenses due to a full year's operation of the Great Basins properties and increased production department staffing to manage the substantial increase in wells and facilities acquired.

Petroleum and Gas Revenue Taxes (PGRT) increased 110% to $4.0 million from $1.9 million a year ago. This substantial increase was due to a full years levy of the tax versus nine months in fiscal 1981. In addition, the effective rate of PGRT was increased from 8% to 12% on January 1, 1982 and declined to 11% on July 1, 1982. A further new tax on Canadian oil revenues, the Incremental Oil Revenue Tax (IORT) was introduced on January 1, 1982 and $.3 million had been incurred before this tax was suspended for one year on June 1, 1982.

The operating expenses of the continuing industrial operations increased to $6.8 million from $6.6 million in 1981. The current year's expenses include a provision for loss of $1.6 million on the inventory of Lift Systems International which reflects management's estimate of the net realizable value of this inventory.

Depletion and depreciation of $17.2 million for the current fiscal year compares with a provision of $11.5 million in 1981. This increase is attributable to the additions to the depletable assets previously excluded as well as significant expenditures in the year with no corresponding increase in reserves. Although the estimated present value of the Company's world-wide assets is significantly in excess of their carrying value, the estimated present value of the U.S. oil and gas reserves and non-producing lands is significantly below cost due to the disappointing results from an aggressive exploration program. The required review of the carrying value of these assets on a country-by-country basis dictates that a writedown of $23.8 million be recorded in 1982.

General and administrative expenses increased to $8.8 million in 1982 from $5.3 million a year ago primarily as a result of administrative and legal expenses of $2.2 million incurred by J.E. Carter Energy, Inc. These expenses will be substantially eliminated in future as Carter is being reorganized under Chapter 11 of the U.S. Bankruptcy Code. The operation of Canso's new office in Australia also added $.3 million to administrative costs in 1982.

Interest on long term debt increased substantially to $28.6 million for 1982 from $6.0 million last year. This increase is primarily attributable to bank borrowings of $130 million, on September 1, 1981, to finance the acquisition of the Great Basins companies, plus interest on further bank borrowings throughout the 1982 fiscal year. A full year's interest was also incurred on the $50 million of 10 1/2% convertible debentures, compared with only four months interest in fiscal 1981.

The current income tax recovery of $4.5 million relates to the Alberta Royalty Tax Credit program.

The deferred income tax recovery of $6.2 million recognizes the benefits of future tax reductions which are reasonably assured as a result of the losses suffered in the current year. Further details of the income tax provision are included in Note 7 to the Consolidated Financial Statements.

b) Discontinued Operations

The loss from discontinued operations, described in Note 3 to the Consolidated Financial Statements, of $1.7 million compares to a loss of $.2 million in 1981. The increase is due primarily to the inclusion of the operations of Spencer's Well Service Inc. acquired in August, 1981.

c) Extraordinary items

Extraordinary items for the current year of $3.6 million reflect a provision for losses which are expected on the disposition of the assets of discontinued operations. The extraordinary items for 1981 totalled $25,000, including a recovery of U.S. taxes of $.9 million, a gain on sale of stock of $.3 million and reimbursement of shareholder committee costs of $1.2 million.

Capital Expenditures and Commitments

Capital expenditures in 1982 amounted to $35.4 million, down from $58.6 million a year ago. Exploration and development programs in the United States and Australia resulted in capital expenditures of $14 million and $15.3 million respectively.

Capital expenditure commitments at the end of the fiscal year were reduced substantially. The Company has withdrawn from all exploration programs in the United States and has only small ongoing development commitments in Canada and the U.S. Development projects are only being undertaken if they provide a quick payout. In Australia the Company has reached agreement to maintain a carried interest in the Amadeus exploration program, which will entail no further outlay of funds. Commitments on EP114 in Western Australia have also been eliminated by converting to a carried working interest position. Exploration work on ATP 239 in Queensland has been put on hold and negotiations are in progress to defer the drilling commitments on this permit. Canso's participation in the Mereenie oilfield development project is being maintained.

Capital Resources & Liquidity

The Company's bank line of credit was increased to $192.7 million in November 1982. The unused portion of this credit line, together with internally generated cash flow and other receipts, are forecast to be adequate to finance the 1983 capital budget and year-end working capital deficiency of $3.3 million.

Declining interest rates, increased product prices and new production coming on stream are expected to improve United Canso's operating cash flow position in fiscal 1983. To help protect the Company from the possibility of higher interest rates in the future, a program has commenced to lock-in interest rates on approximately $40 million of debt for periods of three to five years.

Although U.S. assets have been written down for accounting purposes, the underlying value of the Company's assets continues to be well in excess of their carrying value overall. The estimated net present value of the pre-tax cash flows of the Company's proven and probable reserves discounted at 15% is $691 million. The carrying value of those same properties is $262 million.

Inflation Accounting

In October, 1982 the Canadian Institute of Chartered Accountants issued a Recommendation entitled Reporting the Effects of Changing Prices which will require the disclosure of information related to the effects of inflation on the financial statements, beginning with the 1984 fiscal year of the Company.

United Canso Oil & Gas Ltd.

Summary of Quarterly Financial Results

(unaudited)

For the years ended September 30, 1982 and 1981

	Revenues	(Loss) Earnings before Extraordinary Items Amount	(Loss) Earnings before Extraordinary Items Per Share	Net (Loss) Earnings Amount	Net (Loss) Earnings Per Share	Funds Generated from Operations
	(thousands of Canadian dollars, except per share amounts)					
First Quarter						
1982	$12,166	$ (3,853)	$(0.56)	$ (3,853)	$(0.56)	$ (2,837)
1981	5,577	2,152	0.33	2,669	0.40	4,015
Second Quarter						
1982	12,158	(2,693)	(0.39)	(2,693)	(0.39)	(1,407)
1981	11,805	1,778	0.27	1,024	0.16	5,645
Third Quarter						
1982	12,231	(1,931)	(0.28)	(1,931)	(0.28)	(825)
1981	11,729	1,134	0.17	1,451	0.22	5,101
Fourth Quarter						
1982	7,581	(34,963)	(5.09)	(38,609)	(5.62)	(3,448)
1981	11,091	(4,893)	(0.72)	(4,948)	(0.73)	906
Year						
1982	44,136	(43,440)	(6.32)	(47,086)	(6.85)	(8,517)
1981	40,202	171	0.03	196	0.03	15,667

Market Prices of Common Shares

	Toronto Stock Exchange High	Toronto Stock Exchange Low	Pacific Stock Exchange High	Pacific Stock Exchange Low
	(Canadian dollars)		(U.S. dollars)	
First Quarter				
1982	$16.25	$11.25	$13.63	$ 9.13
1981	25.38	20.00	21.88	16.25
Second Quarter				
1982	11.75	5.00	10.00	4.00
1981	29.88	19.38	25.38	16.25
Third Quarter				
1982	8.75	4.75	7.38	3.38
1981	30.00	23.50	25.38	19.25
Fourth Quarter				
1982	5.13	2.80	4.13	2.75
1981	24.50	12.88	20.50	10.63
Year				
1982	16.25	2.80	13.63	2.75
1981	30.00	12.88	25.38	10.63

Number of Security Holders

As of September 30, 1982, the number of holders of common stock was 9,453, including brokers, trust companies, individuals and corporations.

Consolidated Statement of (Loss) Earnings

Three years ended September 30, 1982
(thousands of Canadian dollars, except share and per share amounts)

	1982	1981	1980
Revenue			
Crude oil	$ 16,112	$ 10,733	$ 8,470
Natural gas	22,671	16,621	5,385
Industrial	4,463	6,676	
Interest	455	5,489	2,685
Other	435	683	681
	44,136	40,202	17,221
Expenses			
Operating			
Crude oil and natural gas	7,325	4,498	3,624
Petroleum and Gas Revenue Tax	3,992	1,922	
Industrial	6,821	6,565	
Depletion and depreciation	17,223	7,386	6,956
Writedown of oil and gas properties (Note 2)	23,814	3,872	2,375
General and administrative	8,786	5,273	3,868
Interest on long term debt	28,591	5,952	
Equity in losses of affiliates	61	85	973
	96,613	35,553	17,796
(Loss) earnings from continuing operations before income taxes and extraordinary items	(52,477)	4,649	(575)
Provision for income taxes (Note 7)			
Current	(4,500)	128	120
Deferred	(6,175)	4,153	(44)
	(10,675)	4,281	76
(Loss) earnings from continuing operations before extraordinary items	(41,802)	368	(651)
Loss from discontinued operations (Note 3)	(1,638)	(197)	
(Loss) earnings before extraordinary items	(43,440)	171	(651)
Extraordinary items (Note 10)	(3,646)	25	174
Net (loss) earnings	$ (47,086)	$ 196	$ (477)
(Loss) earnings per share			
From continuing operations	$ (6.08)	$ .06	$ (.10)
From discontinued operations	$ (.24)	$ (.03)	
Before extraordinary items	$ (6.32)	$ .03	$ (.10)
After extraordinary items	$ (6.85)	$ .03	$ (.07)
Weighted average number of shares outstanding	6,871,112	6,645,526	6,574,796

See accompanying notes

Consolidated Statement of (Deficit) Retained Earnings

Three years ended September 30, 1982
(thousands of Canadian dollars)

	1982	1981	1980
Balance at beginning of year	**$ 27,159**	$26,963	$ 41,597
Net (loss) earnings	**(47,086)**	196	(477)
Stock dividend			(14,157)
Balance at end of year	**$(19,927)**	$27,159	$ 26,963

See accompanying notes

Auditors' Report

To the Shareholders of
United Canso Oil & Gas Ltd.

We have examined the consolidated balance sheets of United Canso Oil & Gas Ltd. as at September 30, 1982 and 1981 and the consolidated statements of (loss) earnings, (deficit) retained earnings and changes in financial position for the three years ended September 30, 1982. Our examination was 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, 1982 and 1981 and the results of its operations and the changes in its financial position for the three years ended September 30, 1982 in accordance with accounting principles generally accepted in Canada applied on a consistent basis.

Calgary, Canada
December 13, 1982

Clarkson Gordon
Chartered Accountants

Consolidated Balance Sheets

September 30, 1982 and 1981
(thousands of Canadian dollars)

Assets

	1982	1981
Current		
Cash	$ 187	
Cash held in trust (Note 9)	488	
Accounts receivable	11,612	$ 15,818
Inventories	6,623	7,189
Net assets of discontinued operations (Note 3)	321	5,317
Other assets	670	457
	19,901	28,781
Investments and advances (Note 4)	16,875	13,797
Property and equipment (including oil and gas properties accounted for by the full cost method) (Note 5)	261,596	267,282
	$298,372	$309,860

Liabilities and Shareholders' Equity

	1982	1981
Current		
Bank indebtedness		$ 7,822
Accounts payable	$ 16,737	15,760
Accrued liabilities	1,293	7,696
Long term debt due within one year (Note 6)	5,159	3,096
	23,189	34,374
Long term debt (Note 6)	239,106	191,191
Deferred revenue	10,700	5,584
Deferred income taxes (Note 7)	3,441	9,689
Shareholders' equity		
Share capital (Note 8)		
Authorized		
10,000,000 preferred shares, par value $10 each		
25,000,000 common shares, par value $1 each		
Issued		
6,871,103 common shares (1981 — 6,871,114)	6,871	6,871
Contributed surplus (Note 8)	34,992	34,992
	41,863	41,863
(Deficit) retained earnings	(19,927)	27,159
	21,936	69,022
Contingencies (Note 9)		
	$298,372	$309,860

On Behalf of the Board:

Director Robert W. St. Clair

Director George H. Laycraft

See accompanying notes

UNITED Canso OIL & GAS LTD.

Consolidated Statement of Changes in Financial Position

Three years ended September 30, 1982
(thousands of Canadian dollars)

	1982	1981	1980
Source of funds			
(Loss) earnings before extraordinary items	**$(43,440)**	$ 171	$ (651)
Items not affecting funds			
Depletion and depreciation	**17,223**	7,386	6,956
Writedown of oil and gas properties	**23,814**	3,872	2,375
Deferred income taxes	**(6,175)**	4,153	384
Equity in losses of affiliates	**61**	85	973
Funds (used in) generated from operations	**(8,517)**	15,667	10,037
Increase in long term debt	**49,978**	189,154	
Proceeds from issue of shares		3,828	550
Deferred revenue	**5,116**	3,489	
Other	**(73)**	900	(34)
	46,504	213,038	10,553
Application of funds			
Acquisitions		172,517	
Additions to property and equipment	**35,351**	58,606	14,975
Investments and advances	**3,139**	6,935	3,634
Long term debt due within one year	**2,063**	3,096	
Provision for loss on disposal of discontinued operations	**3,646**		
Reimbursement of shareholder committee costs		1,217	
	44,199	242,371	18,609
Increase (decrease) in working capital	**$ 2,305**	$ (29,333)	$ (8,056)
Comprised of			
Cash	**$ 187**	$ (101)	$ (297)
Cash held in trust	**488**		
Marketable securities		(24,537)	(8,326)
Accounts receivable	**(4,206)**	9,833	2,969
Inventories	**(566)**	7,067	
Net assets of discontinued operations	**(4,996)**	5,317	
Other current assets	**213**	185	182
Bank indebtedness	**7,822**	(7,822)	
Accounts payable and accrued liabilities	**5,426**	(16,782)	(3,009)
Deferred income taxes		603	425
Long term debt due within one year	**(2,063)**	(3,096)	
(Decrease) increase in working capital	**2,305**	(29,333)	(8,056)
Working capital (deficiency) at beginning of year	**(5,593)**	23,740	31,796
Working capital (deficiency) at end of year	**$ (3,288)**	$ (5,593)	$23,740

See accompanying notes

Notes to Consolidated Financial Statements

September 30, 1982

1. Summary of significant accounting policies

The financial statements of the Company have been prepared by management in accordance with accounting principles generally accepted in Canada which are substantially in conformity with accounting principles generally accepted in the United States, except as described in Note 11. 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 subsidiaries, which are listed below:

Canso Oil & Gas, Inc.
Canso Resources Limited
Canso Spain, Inc.
Great Basins Minerals Ltd.
Great Basins Oil & Gas Ltd.
Great Basins Petroleum Ltd.
Heritage Industries Ltd.
Imput Pty. Ltd.
J. E. Carter Energy, Inc.
Lift Systems International Inc.
Loucol Petroleum Ltd.
McCullough Ditching & Welding Ltd.
Burl Construction Ltd.
Spencer's Well Service, Inc.

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) Inventories

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

c) Investments

Investments in United Canso Oil & Gas Co. (N.T.) Pty. Ltd. and Magellan Petroleum (N.T.) Pty. Ltd. are accounted for by the equity method. Under this method the investments are carried at cost plus the Company's share of equity in undistributed earnings since acquisition. Other investments are carried at cost and income is recorded only as dividends are declared.

d) 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 the following cost centres: Canada, the United States, Australia, Spain and Italy. 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.

Other property and equipment is carried at cost. Investment tax credits related to equipment are recorded as a reduction of costs.

e) Depletion and depreciation

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 in Canada are based on prices contained in the Energy Pricing and Taxation Agreements and in the United States on current prices except for changes provided by contractual agreements.

Costs incurred in Australia, Spain and Italy and certain undeveloped properties in the United States are excluded from the depletion calculation until the quantities of proved reserves can be ascertained through further exploration and development.

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

f) Mineral interests

Mineral exploration costs are capitalized on a project basis pending commencement of commercial production. When a project is determined to be non-commercial the costs are charged to earnings. At September 30, 1982 no mining projects had entered the commercial production stage.

g) 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.

h) Foreign currency translation

Current assets and current liabilities of foreign subsidiaries are translated into Canadian dollars at year-end rates of exchange. Long term assets and liabilities are translated at rates in effect at the dates the assets were acquired or the obligations incurred. Revenue and expenses are translated using average rates of exchange prevailing throughout the year with the exception of depletion and depreciation which are translated at rates of exchange used for the related assets.

i) Deferred revenue

Payments received for undelivered gas are deferred and are recognized as revenue when deliveries are made or on expiry of the period allowed for such deliveries.

j) Income taxes

The Company follows the tax allocation method of 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, 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.

k) Earnings per share

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

2. Writedown of carrying value of assets

At September 30, 1982 the Company has reduced the carrying value of its oil and gas properties to reflect the net realizable value of the underlying assets.

On a worldwide basis, the underlying value of the Company's oil and gas properties, based on the estimated net present value of future cash flows from proved reserves discounted at 10% assuming constant prices, is greater than their carrying value. However, the assets are recorded on a country by country basis and the carrying value of assets in the U.S. cost centre exceeds their underlying value. The Company has written down the oil and gas properties in the U.S. cost centre by $21,684,000 and in other foreign cost centres by $2,130,000.

In addition, the pump jack inventory of Lift Systems International has been written down $1,607,000.

The Company is of the opinion that these adjustments will result in more realistic depletion of costs against income of future periods.

3. Discontinued operations

The Company has decided to discontinue the operations of pipeline construction, gas plant construction and contract drilling presently carried on by McCullough Ditching & Welding Ltd., Burl Construction Ltd. and Spencer's Well Service, Inc. respectively. The operating losses, which are segregated from those of the Company's continuing operations in the accompanying statement of earnings, are summarized as follows:

	1982	1981
	(thousands of Canadian dollars)	
Revenue	$ 4,322	$1,249
Expenses		
Operating	4,083	1,062
Depreciation	1,080	241
General and administrative	797	143
	5,960	1,446
Loss from discontinued operations	$(1,638)	$ (197)

The net assets of these operations are carried at estimated net realizable value at September 30, 1982 and the provision for loss on disposal of assets related to such operations is disclosed as an extraordinary item in the statement of earnings (See also Note 10).

The net assets of discontinued operations are summarized as follows:

	1982	1981
	(thousands of Canadian dollars)	
Working capital (deficiency)		
Accounts receivable	$ 412	$ 927
Bank indebtedness	(1,056)	(48)
Accounts payable	(678)	(1,130)
Other	178	304
	(1,144)	53
Property and equipment	1,465	5,264
Net assets of discontinued operations	$ 321	$ 5,317

4. Investments and advances

	1982	1981
	(thousands of Canadian dollars)	
Australian companies		
United Canso Oil & Gas Co. (N.T.) Pty. Ltd.		
Equity, (40%)	$ 61	$ 83
Advances	1,838	1,196
	1,899	1,279
Magellan Petroleum (N.T.) Pty. Ltd.		
Equity, (30%)	729	659
Advances	3,828	1,479
	4,557	2,138
Total Australian companies	6,456	3,417
Other investments (cost)		
Quoted (market value 1982 — $2,660,000; 1981 — $3,263,000)	3,257	3,218
Unquoted (including advances)	7,162	7,162
	$16,875	$13,797

5. Property and equipment

	Investment at Cost	Accumulated Depletion and Depreciation	Net Investment 1982	Net Investment 1981
	(thousands of Canadian dollars)			
Oil and gas properties, including exploration, development and production equipment expenditures ...	$325,197	$76,519	**$248,678**	$255,130
Industrial operations	3,491	771	**2,720**	2,349
Mineral interests	1,170	569	**601**	911
Other property and equipment	10,558	961	**9,597**	8,892
	$340,416	$78,820	**$261,596**	$267,282

Costs of certain undeveloped properties which have been excluded from the depletion calculation during the year amounted to $29,273,000 (1981 — $26,853,000; 1980 — $170,000). Interest of $6,405,000 (1981 — $644,000; 1980 — nil) relating to undeveloped properties has been capitalized during the year.

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

	Investment at Cost	Accumulated Depletion and Depreciation	Net Investment 1982	Net Investment 1981
	(thousands of Canadian dollars)			
Canada	$248,653	$32,724	**$215,929**	$211,773
United States	68,890	43,957	**24,933**	48,332
Australia and other foreign	22,873	2,139	**20,734**	7,177
	$340,416	$78,820	**$261,596**	$267,282

6. Long term debt

	1982	1981
	(thousands of Canadian dollars)	
Bank production loans		
In Canadian funds with interest at rates varying from prime rate to prime rate plus ½%	**$ 96,419**	$ 76,211
Canadian bankers acceptances at market rates plus ½%	**19,376**	
In U.S. funds with interest at the London Interbank Offered Rate plus 1% (U.S. $50,000,000)	**59,863**	59,863
In U.S. funds with interest at prime rate plus ½% (U.S. $6,832,000)	**8,247**	
	183,905	136,074
10½% convertible subordinated debentures due May 31, 1996	**50,000**	50,000
Other	**10,360**	8,213
	244,265	194,287
Less amounts due within one year	**5,159**	3,096
	$239,106	$191,191

The bank production loans advanced under a line-of-credit of $193 million are revolving and have no specified terms of repayment. Accordingly, none of the production loans have been classified as a current liability. Should the Company not comply with certain conditions defined in the loan agreement, the loans shall convert to a ten year term.

As security for the production loans, the Company has pledged substantially all of its oil and gas properties, has assigned production revenue from those properties, has made a general assignment of book debts and has issued a floating charge debenture on its assets. Furthermore, the loans contain restrictions concerning, among other things, the payment of dividends, the disposition of oil and gas properties and the assumption of additional debt.

The 10½% convertible subordinated debentures are unsecured and are convertible into common shares of the Company up to May 31, 1991 at a price of $31.625 per share. The debentures are redeemable at any time at the Company's option at 108% prior to June 1,1984 and at declining prices thereafter. Commencing on May 31, 1992 the Company is required to provide a sinking fund for redemption in an annual amount not less than 5% nor more than 7% of the debentures outstanding on May 31, 1991.

Approximate instalments of long term debt, excluding bank production loan payments, due in each of the years 1984 to 1987 are:

1984 — $1,906,000; 1985 — $422,000; 1986 — $307,000; 1987 — $308,000.

7. Income taxes

Deferred income taxes are provided as follows:

	1982	1981	1980
	(thousands of Canadian dollars)		
Excess of exploration and development expenditures claimed for tax purposes over depletion provided in the accounts	**$ (831)**	$3,930	$ 194
Excess of income tax capital cost allowance over depreciation provided in the accounts	**(494)**	812	250
Foreign exchange transactions		(547)	(105)
Interest capitalized for tax purposes but expensed in the accounts	**1,940**		
Non-capital loss carry-forward	**(10,069)**		
Deferral of current taxes payable as a result of corporate reorganization	**3,279**		
Other, net		(42)	(383)
	$(6,175)	$4,153	$ (44)

The Company and its Canadian subsidiaries (excluding discontinued operations) have non-capital losses available for carry-forward of approximately $2,170,000 of which $1,193,000 expires in 1986 and $977,000 expires in 1987. The Company's U.S. oil and gas subsidiaries have net operating loss carry-forwards of approximately U.S. $2,718,000 at September 30, 1980 to offset future taxable income, of which U.S. $61,000 expires in 1983, U.S. $2,298,000 expires in 1984 and U.S. $271,000 expires in 1985. The net operating loss carry-forwards for 1981 and 1982 are not included, as the 1981 U.S. tax returns for those years have not yet been finalized. In addition, investment tax credits of U.S. $373,000 are available to reduce future federal tax liabilities. Additional credits may also be available when the 1981 and 1982 returns are finalized. 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:

	1982	1981	1980
	(thousands of Canadian dollars)		
(Loss) earnings from continuing operations before income taxes and extraordinary items	**$(52,477)**	$ 4,649	$ (575)
Average statutory tax rate	**47.8%**	47.8%	47.4%
Computed "expected" income tax provision	**$(25,084)**	$ 2,222	$ (272)
Increase in income taxes resulting from			
Non-deductible royalties and other payments	**4,811**	3,643	1,742
Federal resource allowance	**(3,872)**	(2,522)	(1,226)
Non-deductible Petroleum and Gas Revenue Tax	**1,767**	926	
Losses of subsidiaries	**14,494**	472	
Taxable capital gain	**1,740**		
Non-deductible depletion and depreciation	**1,029**	663	
Other	**(47)**	34	439
	19,922	3,216	955
Decrease in income taxes resulting from			
Earned depletion allowance	**(953)**	(810)	(497)
Reassessment of income taxes	**(426)**	(347)	(110)
Alberta Royalty Tax Credit	**(4,134)**		
	(5,513)	(1,157)	(607)
Actual income tax provision	**$(10,675)**	$ 4,281	$ 76

The components of (loss) earnings before income taxes between domestic and foreign categories together with related income taxes are set out below.

	1982		
	Canada	**U.S.**	**Total**
	(thousands of Canadian dollars)		
Loss from continuing operations before income taxes and extraordinary items	$(23,460)	$(29,017)	$(52,477)
Provision for income taxes			
Current	$ (4,500)		$ (4,500)
Deferred	(6,175)		(6,175)
	$(10,675)		$(10,675)

	1981		
	Canada	**U.S.**	**Total**
	(thousands of Canadian dollars)		
Earnings from continuing operations before income taxes and extraordinary items	$2,799	$1,850	$4,649
Provision for income taxes			
Current	$ 128		$ 128
Deferred	3,258	$ 895	4,153
	$3,386	$ 895	$4,281

	1980		
	Canada	U.S.	Total
	(thousands of Canadian dollars)		
(Loss) earnings from continuing operations before income taxes and extraordinary items	$(1,104)	$ 529	$ (575)
Provision for income taxes			
Current	$ 120		$ 120
Deferred	(218)	$ 174	(44)
	$ (98)	$ 174	$ 76

8. Share capital

a) Issued

	Number of common shares	Share capital, $1 par value	Contributed surplus	Total
		(thousands of Canadian dollars)		
Balance at September 30, 1979	5,938,312	$5,938	$16,097	$22,035
Shares issued				
Equity Incentive Plans	54,300	54	496	550
Stock dividends	597,802	598	13,525	14,123
Balance at September 30, 1980	6,590,414	6,590	30,118	36,708
Shares issued				
Equity Incentive Plans	190,700	191	3,637	3,828
Acquisitions	90,000	90	1,237	1,327
Balance at September 30, 1981	6,871,114	6,871	34,992	41,863
Cancelled	(11)			
Balance at September 30, 1982	6,871,103	$6,871	$34,992	$41,863

b) Share options and incentives

On November 8, 1982 the Board of Directors approved a new incentive program, the 1982 Stock Option Plan ("1982 Plan"). Under the terms of the 1982 Plan 350,000 common shares are reserved for issue of which 262,000 options have been granted (130,000 to officers and 132,000 to other employees). The option price of $3.485 per share represents a 15% discount from the market price at the time of the award. For existing officers and employees, the 1982 Plan provides that 50% of the optioned shares may be exercised immediately and 50% one year after the date granted. For new employees, 100% of the shares granted may be exercised after one year. All options expire three years from the date granted.

All outstanding options granted under previous incentive plans ("Old Plans") have been cancelled.

The Company has made interest free loans to employees under the Old Plans of which $3,456,000 remains outstanding and is included in investments and advances.

Under purchase of shares or exercise of options, the excess of the proceeds over the par value of shares issued is credited to contributed surplus.

c) Shares reserved

After giving effect to the adoption of the 1982 Plan, common shares are reserved a follows:

For conversion of subordinated debentures	1,581,028
Under the 1982 Plan	350,000
	1,931,028

9. Contingencies

The Company has been discharged from the Securities and Exchange Commission's ("SEC") investigation of the Company, Catawba Corporation and Catawba's other client companies one of the conditions of which is that the Company deposit into an interest bearing trust account certain withheld royalty payments. When these funds amount to U.S. $500,000 the Company will distribute such sum, net of any taxes due, by way of a dividend to its shareholders, other than any shareholder who is, or was, also a Catawba shareholder. At September 30, 1982 such withheld royalties amounted to $488,000 (U.S. $395,000).

The civil action brought by the Company and two shareholders against 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. $3,196,000 as a purported settlement in lieu of granting Catawba an overriding royalty on the sale of certain North Sea assets in 1975. The Company's position has recently improved as a result of a court order permitting the filing of the Third Amended Complaint which includes claims against certain defendants based on the SEC investigation referred to in the preceding paragraph. The defendants have filed a motion to dismiss such claims but such motion has not yet been argued because the judge to whom the case has been assigned has been ill for several months. In the opinion of management, the assets of the Company will not be impaired by the outcome of this action.

A wholly-owned subsidiary of Canso Oil & Gas, Inc., J.E. Carter Energy, Inc. ("Carter Energy"), voluntarily filed in Houston, Texas a reorganization proceeding under Chapter 11 of the United States Bankruptcy Code on February 4, 1982. Such filing stayed all outstanding claims which had been brought against Carter Energy to such date. A plan of reorganization has been filed by Carter Energy with the United States Bankruptcy Court in Houston, Texas. As a result of negotiations related to such plan of reorganization, it is anticipated that creditors of Carter Energy and investors in certain of its operations will approve such plan of reorganization. Thereafter, confirmation by the court of the plan also is anticipated. Certain assets of Canso Oil & Gas, Inc. in Texas, including certain of Canso's interests held jointly with Carter Energy, will be contributed to the Carter Energy asset pool under the reorganization plan and the management of the Company is of the opinion that there will be no material financial exposure for Canso Oil & Gas, Inc. under this reorganization save for such contibution of oil and gas interests. The anticipated results of the plan have been reflected in the accompanying financial statements.

On March 19, 1982, Synaventures Limited ("Synaventures") filed an action in the Court of Queen's Bench of Alberta, Judicial District of Calgary against the Company and a wholly owned subsidiary, Great Basins Petroleum Ltd. ("Great Basins"), in which Synaventures alleges that the Company and Great Basins entered into a contract to sell to Synaventures the Company's shares in Great Basins for which Synaventures seeks specific performance or damages in the amount of up to $100 million. No interrogatories have taken place between the Company and Synaventures or discoveries conducted. Negotiations have taken place between the Company and Synaventures and management considers that a settlement will be reached which will not result in any material exposure for the Company.

On August 31, 1982, Compro Limited ("Compro") filed an action in the Court of Queen's Bench of Alberta, Judicial District of Calgary, against the Company carrying on business under the trade name of Lift Systems International. Compro claims damages of $3.82 million for alleged breach of contract for failing to accept delivery of gear reducers. Although preliminary settlement discussions have taken place, management is not able to determine the outcome of this action.

Any settlement resulting from the resolution of all these contingencies will be included in earnings in the period in which such settlement occurs.

Included in current liabilities is $4,984,000 as the Company's one third share of the mortgages in place on a real estate joint venture. Mortgages on the properties held by this joint venture total $14,950,000, for which the Company and its joint venture partners are jointly and severally liable.

10. Extraordinary items

	1982	1981	1980
	(thousands of Canadian dollars)		
Provision for loss on disposal of discontinued operations (Note 3)	**$(3,646)**		
Income taxes of U.S. subsidiaries eliminated on application of net operating loss carry-forwards (Note 7)		$ 895	$174
Reimbursement of shareholder committee costs, approved by shareholder special resolution		(1,217)	
Proceeds from sale of interest in Minex, Inc. previously written off (less applicable income taxes of $68,000)		347	
	$(3,646)	$ 25	$174

11. 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:

	1982	1981	1980
	(thousands of Canadian dollars)		
(Loss) earnings before extraordinary items as reported	**$(43,440)**	$171	$(651)
Adjustments to conform to United States generally accepted accounting principles			
a) Provision for loss on disposal of discontinued operations (Note 10)	**(3,646)**		
b) Foreign currency translation	**(182)**		
(Loss) earnings before extraordinary items	**(47,268)**	171	(651)
Extraordinary items		25	174
Net (loss) earnings	**$(47,268)**	$196	$(477)
(Loss) earnings per share			
Before extraordinary items	**$ (6.88)**	$ .03	$ (.10)
After extraordinary items	**$ (6.88)**	$ .03	$ (.07)

(a) 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.

(b) The United States Financial Accounting Standards Board Statement No. 52 requires that the Company translate its foreign denominated debt at the current rate of exchange versus the rate in effect at the date the obligation was incurred. If the Company had adopted the provisions of Statement No. 52, long term debt would have increased and retained earnings would have decreased by $182,000 (1981 and 1980 — NIL).

12. Related party transactions

The law firm of Holland and Holland has rendered legal services to the Company for fees of $92,000 (1981 — $138,400; 1980 — $24,066). Mr. J. W. Holland, Secretary and a director of United Canso, is a partner in that law firm. Mr. Holland has received no direct compensation from the Company in his capacity as Secretary.

The 10½% convertible subordinated debentures referred to in Note 6 were issued in 1981 to related parties as follows:

Thomas J. Jacobsen	$10,000,000
John Duby	$5,000,000

Mr. Jacobsen and Dr. Duby are directors of United Canso.

13. Remuneration of directors

Aggregate remuneration paid or payable during the year to directors of the Company in their capacity as directors amounted to $94,576 (1981 — $76,125; 1980 — $75,049).

14. 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 $120,960 (1981 -$46,431; 1980 — $42,204) 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.

15. Segmented information

The Company is engaged in two industries i) exploration for and development of crude oil and natural gas and ii) oilfield manufacturing and service (industrial), with operations primarily in Canada and the United States. The following is an analysis of certain financial information by industry segments and geographic area.

	1982	1981	1980
	(thousands of Canadian dollars)		
Industry segments			
Revenue			
Crude oil and natural gas	$ 38,783	$ 27,354	$13,855
Industrial	4,463	6,676	
	$ 43,246	$ 34,030	$13,855
Operating (loss) income			
Crude oil and natural gas	$ (13,206)	$ 9,864	$ 900
Industrial	(2,723)	(77)	
	(15,929)	9,787	900
Other			
Interest and other revenue	890	6,172	3,366
General and administrative	(8,786)	(5,273)	(3,868)
Interest on long term debt	(28,591)	(5,952)	
Equity in losses of affiliates	(61)	(85)	(973)
Income taxes	10,675	(4,281)	(76)
Loss from discontinued operations	(1,638)	(197)	
Extraordinary items	(3,646)	25	174
	(31,157)	(9,591)	(1,377)
Net (loss) earnings	$ (47,086)	$ 196	$ (477)

Identifiable assets			
Crude oil and natural gas	**$262,048**	$278,409	$68,238
Industrial	**8,930**	5,990	
	270,978	284,399	68,238
Other (including net assets of discontinued operations)	**27,394**	25,461	8,830
	$298,372	$309,860	$77,068

	1982	1981	1980
	(thousands of Canadian dollars)		
Geographic area			
Revenue			
Canada	**$ 34,268**	$ 26,336	$ 8,757
United States	**8,978**	7,694	5,098
	$ 43,246	$ 34,030	$13,855
Operating (loss) income			
Canada	**$ 12,178**	$ 10,409	$ 2,171
United States	**(25,977)**	2,617	1,104
Other foreign	**(2,130)**	(3,239)	(2,375)
	(15,929)	9,787	900
Other			
Interest and other revenue	**890**	6,172	3,366
General and administrative	**(8,786)**	(5,273)	(3,868)
Interest on long term debt	**(28,591)**	(5,952)	
Equity in losses of affiliates	**(61)**	(85)	(973)
Income taxes	**10,675**	(4,281)	(76)
Loss from discontinued operations	**(1,638)**	(197)	
Extraordinary items	**(3,646)**	25	174
	(31,157)	(9,591)	(1,377)
Net (loss) earnings	**$ (47,086)**	$ 196	$ (477)
Identifiable assets			
Canada	**$234,106**	$232,414	$55,163
United States	**35,616**	54,304	14,788
	269,722	286,718	69,951
Other (including net assets of discontinued operations)	**28,650**	23,142	7,117
	$298,372	$309,860	$77,068

16. Costs incurred and capitalized costs related to oil and gas producing activities

The following table sets forth (i) costs incurred in oil and gas producing activities (whether charged to expense or capitalized) and (ii) the aggregrate capitalized costs relating to oil and gas producing activities and the aggregate amount of depletion and depreciation and writedown of properties:

	1982				
	Canada	United States	Australia	Other	Total
Capitalized costs incurred					
Property acquisition	$ 716	$ 600			$ 1,316
Exploration	2,157	10,132	$12,377	$ 957	25,623
Development	3,054	764			3,818
Mineral exploration	259				259
Interest capitalized		2,507	2,967		5,474
	$6,186	$14,003	$15,344	$ 957	$36,490
Costs charged to expense					
Production	$5,486	$ 1,839			$ 7,325
Depletion and depreciation	4,207	11,566			15,773
Writedown of properties	305	21,370		$2,139	23,814
	$9,998	$34,776		$2,139	$46,912

	1981				
	Canada	United States	Australia	Other	Total
Capitalized costs incurred					
Property acquisition	$ 2,206	$16,934		$ 238	$19,378
Exploration	4,108	10,212	$ 4,306	5,736	24,362
Development	4,422	573			4,995
Mineral exploration	279				279
Interest capitalized	644				644
	$11,659	$27,719	$ 4,306	$ 5,974	$49,658
Costs charged to expense					
Production	$ 3,587	$ 911			$ 4,498
Depletion and depreciation	3,665	3,533			7,198
Writedown of properties		633		$ 3,239	3,872
	$ 7,252	$ 5,077		$ 3,239	$15,568

	1980			
	Canada	United States	Other	Total
Capitalized costs incurred				
Property acquisition	$ 1,150	$ 215		$ 1,365
Exploration	3,678	636	$ 2,755	7,069
Development	2,844	2,826		5,670
Mineral exploration	386			386
	$ 8,058	$ 3,677	$ 2,755	$14,490
Costs charged to expense				
Production	$ 2,553	$ 1,071		$ 3,624
Depletion and depreciation	4,033	2,923		6,956
Writedown of properties			$ 2,375	2,375
	$ 6,586	$ 3,994	$ 2,375	$12,955

17. Subsequent events

The Company has reached an agreement with Magellan Petroleum Corporation, the controlling shareholder of United Canso Oil & Gas Co. (N.T.) Pty. Ltd. and Magellan Petroleum (N.T.) Pty. Ltd. to exchange the Company's 40% and 30% interests respectively in these companies for direct working interests in certain Australian permits. The relevant documentation to accomplish this exchange has been lodged by Magellan with the court in Queensland, Australia and the hearing is set for December 15, 1982 for final court approval.

Supplementary Information

Reserve Recognition Accounting (Unaudited)

a) Introduction

The United States Securities and Exchange Commission ("SEC") believes that neither of the traditional methods of accounting (full cost and successful efforts) provides sufficient information on the financial position and operating results of oil and gas producers. Although the SEC has ceased developing Reserve Recognition Accounting ("RRA") as a method of accounting for oil and gas producing activities in the primary financial statements, the SEC regulations still require that the Company prepare supplementary information in accordance with RRA. The following information is disclosed in compliance with the regulations of the SEC.

b) Estimated quantities of proved reserves

Substantially all of the crude oil and natural gas reserves of the Company are developed. As prescribed by the SEC, the quantities of such reserves are presented net after royalties and form the basis for the calculations included in the following sections. The quantities for 1982 are based upon reports of the Company's reservoir engineers and for prior years upon reports of McDaniel & Associates Consultants Ltd. and James A. Lewis Engineering Co., Ltd., independent reservoir engineers, and have been calculated in accordance with SEC definitions. These reports do not include any reserves for Australia where the Company is converting its equity interest in certain companies which have reserves into direct working interests.

Estimated Proved Oil and Gas Reserves
Three years ended September 30, 1982

	Canada		United States		Total	
	Crude Oil & NGL's	Natural Gas	Crude Oil & NGL's	Natural Gas	Crude Oil & NGL's	Natural Gas
Reserves Sept. 30, 1979	3,794	55,490	260	3,526	4,054	59,016
Revisions to previous estimates	(152)	(2,871)	48	928	(104)	(1,943)
	3,642	52,619	308	4,454	3,950	57,073
Discoveries	107	5,692	86		193	5,692
Production	(394)	(2,702)	(95)	(736)	(489)	(3,438)
Reserves Sept. 30, 1980	3,355	55,609	299	3,718	3,654	59,327
Revisions to previous estimates	202	3,787	237	319	439	4,106
	3,557	59,396	536	4,037	4,093	63,433
Discoveries	38	4,191	88	79	126	4,270
Acquisition of reserves	1,408	228,514	203	120	1,611	228,634
Production	(413)	(7,066)	(110)	(1,056)	(523)	(8,122)
Reserves Sept. 30, 1981	4,590	285,035	717	3,180	5,307	288,215
Revisions to previous estimates	358	(17,208)	39	77	397	(17,131)
	4,948	267,827	756	3,257	5,704	271,084
Discoveries	24	742	16	876	40	1,618
Disposition of reserves			(68)		(68)	
Production	(442)	(8,664)	(134)	(584)	(576)	(9,248)
Reserves Sept. 30, 1982	4,530	259,905	570	3,549	5,100	263,454

Crude oil and natural gas liquids stated in thousands of barrels.
Natural gas stated in millions of cubic feet.

c) **Estimated future net revenues and present value thereof**

As prescribed by the SEC, estimated future net revenues are computed by applying current year prices of oil and gas (with consideration of future price changes to the extent provided by contractual arrangements) to estimated future production of proved oil and gas reserves and deducting future expenditures (based on current year costs) to be incurred in developing and producing the proved reserves. In Canada the increases in selling prices and taxes contained in the Energy Pricing and Taxation Agreements have been reflected in the computation and inflation is built into costs for the years where pricing is guaranteed. As prescribed by the SEC, a 10% discount factor has been applied to the estimated future net revenues to determine the present value.

Estimated Future Net Revenues

	1982		
	Canada	U.S.	Total
	(thousands of Canadian dollars)		
Estimated Future Net Revenues			
1983	$ 28,999	$ 7,521	$ 36,520
1984	35,586	5,503	41,089
1985	42,121	3,764	45,885
Remaining	847,863	11,517	859,380
	$ 954,569	$28,305	$ 982,874
Present Value of Estimated Future Net Revenues	$ 365,013	$21,135	$ 386,148

	1981		
	Canada	U.S.	Total
	(thousands of Canadian dollars)		
Estimated Future Net Revenues			
1982	$ 21,470	$ 6,656	$ 28,126
1983	23,171	5,617	28,788
1984	29,747	4,455	34,202
Remaining	885,951	11,609	897,560
	$ 960,339	$28,337	$ 988,676
Present Value of Estimated Future Net Revenues	$ 333,515	$21,593	$ 355,108

	1980		
	Canada	U.S.	Total
	(thousands of Canadian dollars)		
Estimated Future Net Revenues			
1981	$ 7,209	$ 4,739	$ 11,948
1982	6,530	3,788	10,318
1983	6,293	2,700	8,993
Remaining	91,269	4,804	96,073
	$111,301	$16,031	$127,332
Present Value of Estimated Future Net Revenues	$ 50,463	$12,976	$ 63,439

d) Statement of Reserve Recognition Accounting Policies

Beginning in 1979, the SEC required that companies present unaudited financial information on the basis of RRA. The accounting policies set forth below have been followed in preparing the RRA presentations. Under RRA, an asset is recognized and earnings recorded when proved reserves are added through exploration and development activities. A dollar valuation of proved reserves is developed as follows:

(1) Estimates are made of quantities of proved reserves and the future period during which they are expected to be produced based on current economic conditions;

(2) The estimated future production of proved reserves is priced on the basis of year-end prices except that future prices are increased for fixed and determinable escalation provisions in contracts including the Canadian Energy Pricing and Taxation Agreements (to a maximum of 75% of the current world oil price).

(3) The resulting future gross revenue streams are reduced by estimated future costs to develop and to produce the proved reserves, based on current cost estimates (except for Canadian costs which are inflated in the years when prices have been escalated).

(4) The resulting future net revenue streams are reduced to present value amounts by applying a 10 percent discount factor.

As acknowleged by the SEC, this method of accounting is not intended as an estimate of the fair market value of a company's oil and gas properties nor does it represent the type of earnings normally reported in the financial statements. Due to many uncertainties inherent in this method of accounting, the Company considers RRA to be potentially very misleading.

e) Summary of Oil and Gas Producing Activities on the basis of RRA

The following RRA Summary reports the present value of future revenues (net of royalties, exploration, development and production expenses) from proved reserves added during the year, together with revisions to estimates of reserves proved in prior years and accretion of discount. Accretion of discount is a revision due to the process of discounting. The revision is due to the production schedule of proved reserves being advanced one year on the discount table. Each year as full production is realized the discount factor becomes smaller, a higher present value amount results and income is recognized due to the increase. Revisions to prior year estimates are broken down between those attributable to changes in prices and costs and all other, which includes changes in the quantity of the reserve estimates and changes in estimated rates of production. Current years exploration and development expenditures in relation to proved reserves are deducted to arrive at earnings for RRA. Income taxes are calculated for Canada and the United States by applying appropriate statutory tax rates to RRA results before provision for income taxes (after taking into account the effect of the non-deductible revenue taxes and crown royalties). Foreign losses have been tax effected in Canada and the United States.

Summary of Oil and Gas Producing Activities On the Basis of Reserve Recognition Accounting
Three years ended September 30, 1982

	Canada	United States	Foreign	Total 1982	Total 1981	Total 1980
	(thousands of Canadian dollars)					
Additions to estimated proved reserves	$ 1,193	$ 11,999		**$ 13,192**	$ 7,361	$ 6,987
Revision to reserves proved in prior years						
Changes in prices	(16,894)	4,676		**(12,218)**	15,170	14,068
Accretion of discount	31,198	1,837		**33,035**	9,738	4,244
Other	37,070	(10,492)		**26,578**	6,344	10,659
	51,374	(3,979)		**47,395**	31,252	28,971
Exploration and development expenses	(5,927)	(25,879)	$ (691)	**(32,497)**	(19,248)	(4,166)
RRA earnings before income taxes	46,640	(17,859)	(691)	**28,090**	19,365	31,792
Provision for income taxes	(27,471)	8,215	330	**(18,926)**	(11,238)	(16,184)
Net earnings (loss) from oil and gas producing activities on the basis of RRA (before other income and expenses)	$ 19,169	$ (9,644)	$ (361)	**$ 9,164**	$ 8,127	$ 15,608

f) **Changes in Present Value of Estimated Future Net Revenue from Proved Oil and Gas Reserves**

This summary reconciles future discounted net reserves at September 30, 1982 with those reported at September 30, 1981 and 1980.

Changes in Present Value of Estimated Future Net Revenues from Proved Reserves On the Basis of Reserve Recognition Accounting
Three years ended September 30, 1982

	Canada	United States	Total 1982	Total 1981	Total 1980
	(thousands of Canadian dollars)				
Balance at beginning of year	$333,515	$ 21,593	**$355,108**	$ 63,439	$ 41,344
Revisions to reserves proved in prior years	51,374	(3,979)	**47,395**	31,252	28,971
	384,889	17,614	**402,503**	94,691	70,315
Additions to estimated proved reserves	1,193	11,999	**13,192**	7,361	6,987
Acquisition (disposition) of proved reserves		(1,389)	**(1,389)**	273,990	
Production, net of lifting costs	(21,069)	(7,089)	**(28,158)**	(20,934)	(13,863)
Balance at end of year	$365,013	$ 21,135	**$386,148**	$355,108	$ 63,439

UNITED CANSO OIL & GAS LTD.

Five-Year Statistical Review

	1982	1981	1980	1979	1978
FINANCIAL					
REVENUE	$ 44,259	$ 40,531	$ 16,975	$ 13,306	$ 10,911
EXPENSES					
Operating	18,138	12,985	3,624	2,487	1,855
Depletion and depreciation including writedown of properties	41,037	11,258	9,331	5,772	4,308
General and administrative	8,786	5,273	3,868	2,555	2,230
Exchange (gains) losses	123	329	(246)	475	(2,761)
Interest on long term debt	28,591	5,952			
Equity in losses of affiliates	61	85	973	879	786
Provision for income taxes	(10,675)	4,281	76	1,883	2,344
	86,061	40,163	17,626	14,051	8,762
(Loss) earnings from continuing operations before extraordinary items	(41,802)	368	(651)	(745)	2,149
Loss from discontinued operations	(1,638)	(197)			
(Loss) earnings before extraordinary items	(43,440)	171	(651)	(745)	2,149
Extraordinary items	(3,646)	25	174		
NET (LOSS) EARNINGS	$ (47,086)	$ 196	$ (477)	$ (745)	$ 2,149
Per Share: from continuing operations	$ (6.08)	$ 0.06	$ (0.10)	$ (0.11)	$ 0.33
: before extraordinary items	$ (6.32)	$ 0.03	$ (0.10)	$ (0.11)	$ 0.33
: after extraordinary items	$ (6.85)	$ 0.03	$ (0.07)	$ (0.11)	$ 0.33
FUNDS GENERATED FROM OPERATIONS	(8,517)	15,667	10,037	7,572	8,831
Per Share	(1.23)	2.21	1.53	1.16	1.35
CAPITAL EXPENDITURES					
Property and equipment	35,351	58,606	14,975	10,335	14,830
Investments and advances	3,139	6,935	3,634	1,968	523
WORKING CAPITAL (DEFICIENCY)	(3,288)	(5,593)	23,740	31,796	36,527
Per Share	(0.48)	(0.84)	3.60	4.86	5.59
LONG TERM DEBT	239,106	191,191			
SHAREHOLDER'S EQUITY	21,936	69,022	63,671	63,632	64,377
Per share	3.19	10.05	9.66	10.72	10.84
TOTAL ASSETS	298,372	309,860	77,068	74,235	76,560
SHARES					
Average Number of Shares outstanding (000's)	6,871	6,646	6,574	6,536	6,536
Market price (Canadian $) — High	16.25	30.00	30.00	18.90	12.83
— Low	2.80	12.88	11.25	7.88	7.20
(U.S. $) — High	13.63	25.38	24.75	16.31	9.90
— Low	2.75	10.63	8.66	7.43	5.85

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%.

(3) Revenues exclude exchange gains and losses which are included in revenue on the Consolidated Statement of Earnings.

	1982	1981	1980	1979	1978
OPERATING					
PRODUCTION — gross before royalties — daily					
Crude oil and natural gas liquid-bbls	2,429	2,455	2,250	2,363	2,187
Natural gas-thousands of cubic feet	34,220	37,736	13,250	9,450	8,464
GROSS RESERVES — proven and probable					
Crude oil — thousands of bbls	19,590	15,050	7,103	7,269	7,726
Natural gas — millions of cubic feet	469,253	534,223	95,600	92,803	91,860
DRILLING ACTIVITY					
Gross wells	88	88	131	69	70
Net wells					
Successful	9	29	17	17	17
Dry	4	9	12	5	7
LAND HOLDINGS — thousands of acres					
Gross	34,456	27,275	18,333	19,869	23,635
Net	5,528	10,870	4,336	4,716	4,886

Corporate and Head Office

3700, 700 - 2nd Street S.W.
Calgary, Alberta

Operating Subsidiaries

Canso Oil & Gas, Inc.
Canso Resources Limited
Canso Spain, Inc.
Great Basins Minerals Ltd.
Great Basins Oil & Gas Ltd.
Great Basins Petroleum Ltd.
Heritage Industries Ltd.
Imput Pty. Ltd.
J. E. Carter Energy Inc.
Lift Systems International — a Division of UCOG
Lift Systems International Inc.
Loucol Petroleum Ltd.
McCullough Ditching & Welding Ltd.
Burl Construction Ltd.
Spencer's Well Service, Inc

Registrar and Transfer Agent

Guaranty Trust Company of Canada, Calgary, Alberta

Co-Transfer Agent

First Jersey National Bank, Jersey City, New Jersey

First Interstate Bank of California, Los Angeles, California

Auditors

Clarkson Gordon, Calgary, Alberta

Listings

Toronto, Montreal, Boston & Pacific Stock Exchanges (symbol UTC)
NASDAQ (symbol UCANF)

Officers	Title
DELP, Billy R.	Chairman of the Board
HIEBERT, Donald L.	President and Chief Executive Officer
BANKS, C. David	Senior V.P.
CYCA, Ronald B.	V.P. Production
BROWN, R. James	Treasurer (Appointed December 1, 1982)
HOLLAND, J. William	Secretary
WINTER, Colin Q.	Assistant Secretary (Appointed December 13, 1982)
McMANAMAN, Brian J.	Land Manager (Appointed December 13, 1982)
ROBERTSON, George B.	Assistant Secretary

Board of Directors

Billy R. Delp Fort Worth, Texas Chairman	President, Nu-Way Oil Company
Dr. John Duby Calgary, Alberta	Executive
D. L. Hiebert Calgary, Alberta	President, United Canso Oil & Gas Ltd.
J. William Holland Chicago, Illinois Secretary	Attorney and V.P., Holland & Holland (Associated)
Thomas J. Jacobsen Calgary, Alberta	Executive
Dr. George H. Laycraft Vancouver, British Columbia	Exec. V.P., Chief Exec. Officer and Director Dusty Mac Mines Ltd. (N.P.L.)
Angus A. MacNaughton San Francisco, California Appointed November 18, 1982	President and Chief Executive Officer Genstar Corporation
George B. Robertson Halifax, Nova Scotia	Partner, McInnes, Cooper & Robertson, Lawyer
Robert W. St. Clair Fort Worth, Texas Treasurer	President, Thrift Distributors, Inc.
Sandy S. Sheinin Resigned November 18, 1982	Sheinin & Co.

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1982 Annual Report

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