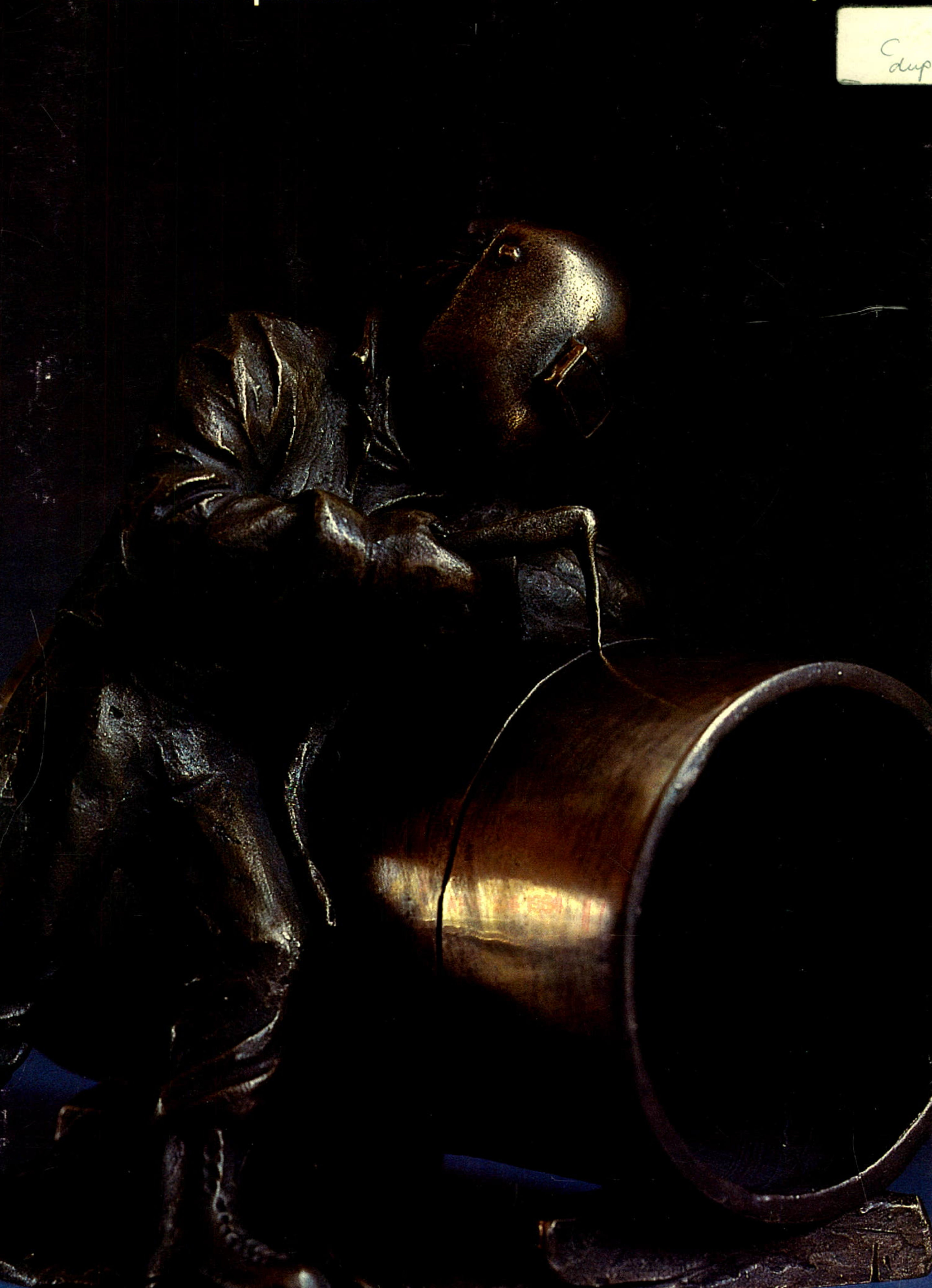
TransCanada PipeLines

Annual Report 1983



The Company

TransCanada PipeLines has assets exceeding $5 billion in Canada, the United States and other countries.

The Company

- is a major purchaser and transporter of Alberta natural gas to domestic and export markets
- owns and operates Canada's major natural gas transmission system from Alberta to Quebec
- owns a 50% interest in Trans Québec & Maritimes Pipeline Inc.
- owns a 44% interest in Foothills Pipe Lines (Sask.) Ltd.
- owns a 50% interest in Great Lakes Gas Transmission Company
- owns a 30% interest in Northern Border Pipeline Company
- has extensive oil and gas interests in western Canada, as well as oil and gas interests in the United States, Indonesia, Australia, Italy, the North Sea
- owns interests in energy-related manufacturing and an ethane and natural gas liquids extraction plant
- carries on studies of natural gas transportation in northern Canada and in the Atlantic provinces
- is participating in a geothermal project in California

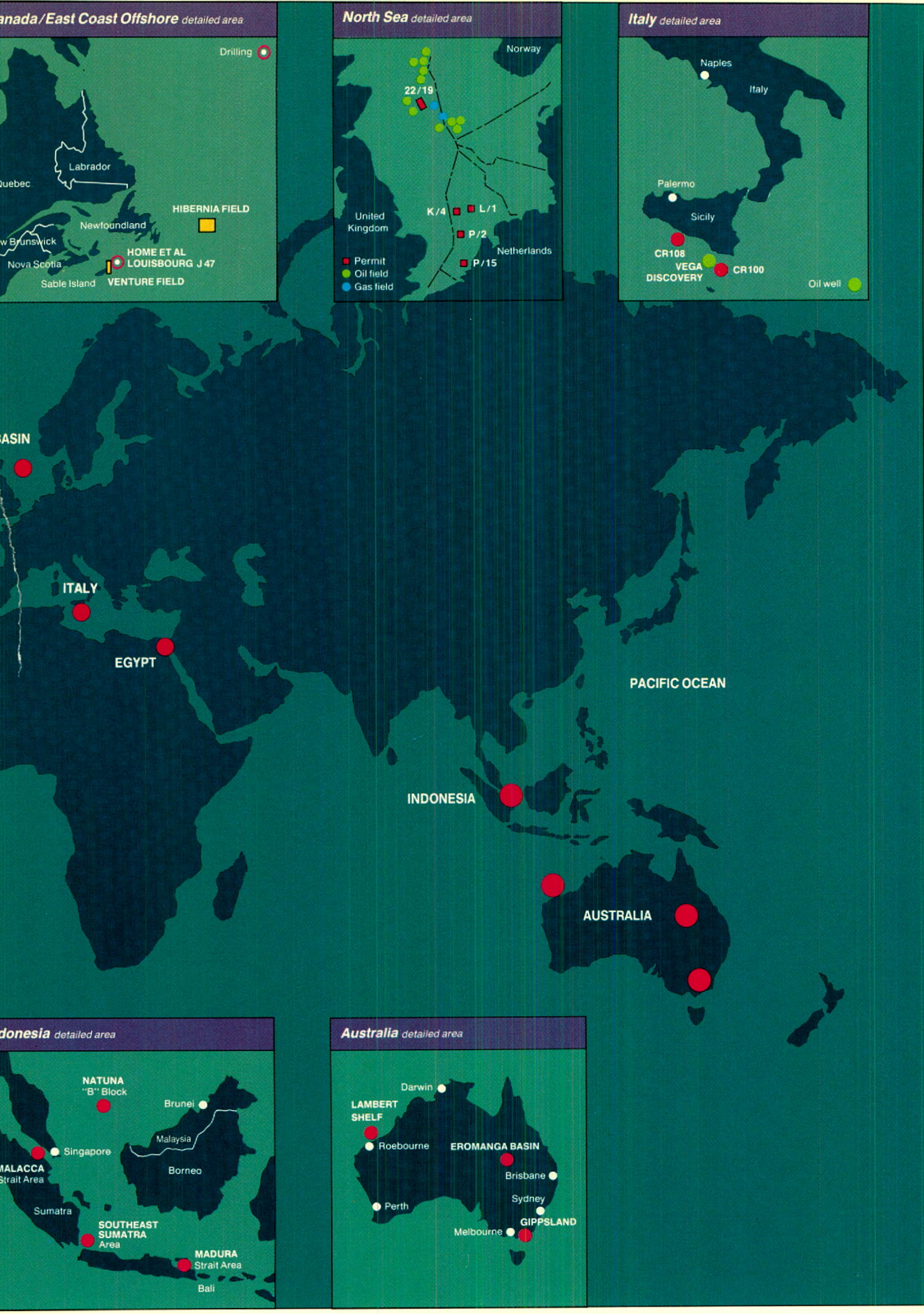
Cover picture
THE FINAL WELD
Limited Edition Bronze Sculpture by Siggy Puchta commissioned to commemorate the 25th anniversary of the completion of the first of the Company's pipelines from Alberta to eastern Canada

Inside front cover
Pine seedlings grown by using surplus heat from compressor engines.
Station 105, Ramore, Ontario.

Index

The Annual Meeting of Shareholders will be held in the Concert Hall of the Royal York Hotel, 100 Front Street West, Toronto, Ontario, on Wednesday, May 2, 1984, commencing at 10:00 o'clock a.m. Toronto time.

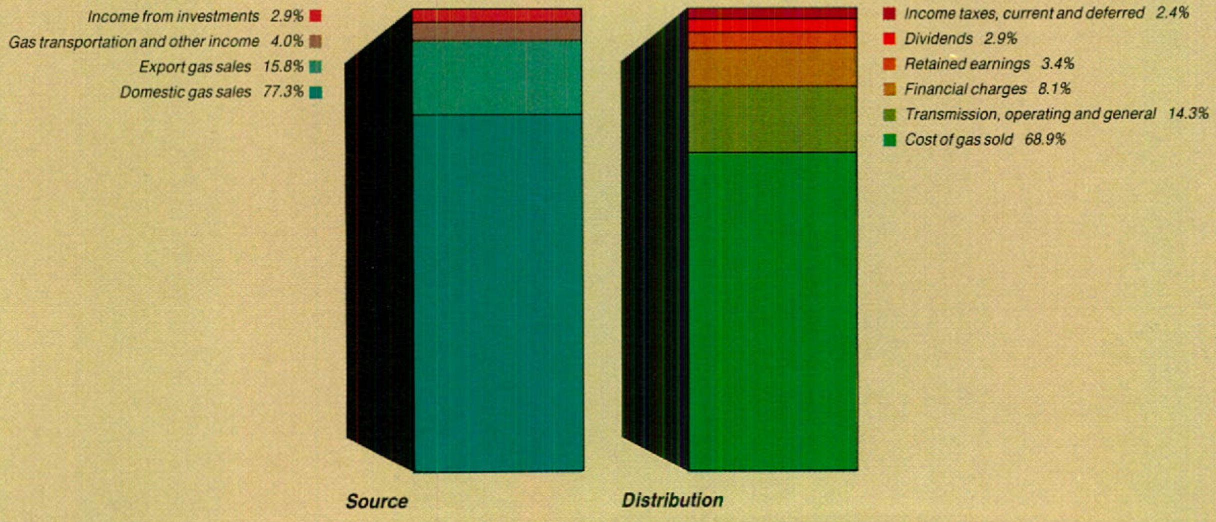
Si vous désirez vous procurer une copie de ce rapport en français, veuillez vous adresser au secrétaire, TransCanada PipeLines, C.P. 54, Commerce Court West, Toronto, Ontario M5L 1C2.


anada/East Coast Offshore detailed area
Drilling
Labrador
Quebec
HIBERNIA FIELD
Newfoundland
w Brunswick
HOME ET AL
LOUISBOURG J 47
Nova Scotia
Sable Island
VENTURE FIELD
North Sea detailed area
Norway
22/19
United Kingdom
K/4
L/1
P/2
Netherlands
P/15
Permit
Oil field
Gas field
Italy detailed area
Naples
Italy
Palermo
Sicily
CR108
VEGA
DISCOVERY
CR100
Oil well
ASIN
ITALY
EGYPT
PACIFIC OCEAN
INDONESIA
AUSTRALIA
donesia detailed area
NATUNA
"B" Block
Brunei
Malaysia
Singapore
MALACCA
Strait Area
Borneo
Sumatra
SOUTHEAST
SUMATRA
Area
MADURA
Strait Area
Bali
Australia detailed area
Darwin
LAMBERT
SHELF
Roebourne
EROMANGA BASIN
Brisbane
Sydney
Perth
GIPPSLAND
Melbourne


ARCTIC ISLANDS
BEAUFORT SEA
CANADA
NORT
SABLE ISLAND
U.S.A.
ATLANTIC OCEAN
PACIFIC OCEAN
Alaska Natural Gas Transportation System
TransCanada PipeLine Alaska Ltd. (proposed)
7% interest Alaska Segment
Foothills Pipe Lines (Yukon) Ltd. (constructed)
Foothills Pipe Lines (Yukon) Ltd. (proposed)
(Connecting System)
TransCanada Border PipeLine Ltd.
Phase 1 — Northern Border Segment 30% interest
Future Extension
Canadian Operations
TransCanada PipeLines
100% Ownership
Trans Québec & Maritimes Pipeline
50% Ownership
Sable Gas Systems Limited
Foothills Pipe Lines (Sask.) Ltd.
44% Ownership
TCPL Resources Ltd.
Areas of principal activity
Connecting System
United States Operations
Great Lakes Gas Transmission Company
50% Ownership
TCPL Resources U.S.A. Ltd.
Areas of principal activity
International Operations
Oil and Gas Interests

Highlights

	1983	1982
Financial (in millions of dollars except for common share data)		
Revenues	3,470.7	3,466.9
Net income	191.8	161.1
Funds generated by operations and equity investments	394.3	326.3
Capital expenditures	303.3	833.0
Total assets	5,034.5	4,716.9
Per share data, after giving effect to two-for-one share split approved February 8, 1984:		
Net income	$2.13	$1.81
Funds generated by operations and equity investments	4.39	3.66
Dividends declared	.75	.59½
Operating		
Pipeline operations		
Gas delivered for sales and transportation (millions of cubic metres)		
annual	28 576	32 497
maximum day	121	125
Oil and gas operations		
Oil and natural gas liquids production (thousands of cubic metres)	795.5	763.9
Natural gas sales (millions of cubic metres)	673.7	687.8



1983 Revenue dollars

To Our Shareholders

In 1983 TransCanada PipeLines completed 25 years as a successful operating company.

Changes in the holdings of the Company's major shareholders were among the most significant events in the anniversary year. Dome Petroleum and Dome Canada disposed of over 32 million of their TransCanada common shares, (restated to reflect a two-for-one share split approved by common shareholders on February 8, 1984) by way of secondary offerings on the open market during 1983. In December, Bell Canada Enterprises Inc. ("BCE") acquired on a post share split basis the remaining 10.6 million common shares held by Dome Canada. As a result of this private purchase and further shares acquired on the same terms on the open market, BCE held at December 31, 1983 42.3% of the Company's common shares.

The growth and stability of TransCanada's income stream and asset base, the strong long-term future in natural gas in Canada, and TransCanada's extensive oil and gas interests in western Canada, were all factors which prompted the BCE investment. No change is anticipated in the corporate direction of TransCanada.

The 25th year was also important in the strategic development of the Company's business horizons. Since 1958, TransCanada has assured Alberta natural gas producers of maximum access to eastern Canadian energy markets by providing low-cost, efficient pipeline transportation. To achieve economies of scale in pipeline transportation, TransCanada has been aggressive in securing export sales in the United States since 1960 and in investing in connecting United States pipeline systems since 1965. The TransCanada system became a mature pipeline system after a significant expansion in the first half of the 1970's and, commencing in 1979, TransCanada made a series of major investments in oil and gas lands in Canada and, on a much smaller scale in the United States and other countries. As a result of growing financial strength and lower requirements for pipeline investment in the near future, a decision was taken during 1983 to increase TransCanada's participation in energy-related projects in the United States, as a prelude to further major pipeline participation in both Canada and the United States. The Company will also increase its direct participation in oil and gas.

1983 Financial Results

TransCanada ended 1983 in excellent financial condition with a strong cash flow. The Company's diversification continued to show beneficial results.

Earnings applicable to common shares increased by 19.1% to $191.8 million in 1983, up from $161.1 million in 1982.

Earnings per common share, restated to reflect the two-for-one share split, increased to $2.13, up from $1.81 in 1982.

Funds generated from operations and equity investments in 1983 were $4.39 per common share, up from $3.66 in 1982.

For the first time, assets exceeded $5 billion.

Dividends

On a post share split basis, dividends declared in 1983 increased to 75 cents per common share, up from 59.5 cents in 1982.

In December 1983, the annual dividend rate was increased to 96 cents per common share effective with the January 31, 1984 dividend payment.

Sales

A combination of warm weather, reduced economic activity, and delays by the Alberta, Canadian and United States governments in resolving natural gas pricing policies, prevented the Company from achieving its full sales potential in 1983. As a result, the most pressing concern to TransCanada during 1983 was the continuing surplus of natural gas deliverability over short-term market demands in both Canada and the United States. This was particularly true in the United States markets served by the Company where United States customers incurred substantial obligations to TransCanada for volumes of gas which they have not taken, but which they are required to pay for under their gas purchase contracts with TransCanada.

During 1983, the Company's total gas sales volumes declined by 9.9%. Sales of natural gas volumes in Canada were down by 4.5%. In the United States markets the reduction was even greater — 36.8% lower than in 1982. Volumes transported by TransCanada for others were also lower.

These reductions resulted in the Company being able to nominate only 48% of the minimum annual obligation under its gas purchase contracts and in the incurring of further take or pay obligations for 1983 of $360 million. Arrangements were made with a syndicate of banks under which the banks made payments to the producers for a substantial portion of this amount.

To stem the decline in export sales markets and to provide new incentives to purchasers to take larger volumes of Canadian natural gas in 1984 and ensuing years, the Company negotiated amendments of its major export sales contracts with United States customers. Some of these amendments were approved by the National Energy Board in January 1984 and are expected to lead to increased sales in 1984 and 1985. Other amendments are awaiting approval.

During late 1983, with a return of more normal temperatures and a strong recovery of sales in the industrial sector of the Canadian energy market, average daily deliveries of natural gas improved by about 5%. In December, a new peak day for 1983

Gordon P. Osler, Chairman

transportation and deliveries of natural gas of 121 million cubic metres was set. In the first quarter of 1984, sales and transportation volumes increased by 1 620 million cubic metres, or 20% higher than in the first quarter of 1983.

In January 1984, a significant approval was received from United States regulatory authorities under which 1.1 million cubic metres daily will be exported into the northeastern United States, commencing in November 1984. Exports of additional short-term volumes of natural gas for Vermont were also approved. However, major new exports will depend on new pricing agreements between Canada and the United States and the solving by the United States of its own domestic pricing problems.

Pipeline Investments

Great Lakes Gas Transmission Company, in which TransCanada has a 50% interest, contributed $9.8 million to investment income in 1983, down from $15.4 million in 1982 due to the reduction in exports of Canadian gas and in volumes transported for eastern Canadian markets.

Northern Border Pipeline Company, in which TransCanada has a 30% interest and Foothills Pipe Lines (Sask.) Ltd., in which TransCanada has a 44% interest, completed their first year of operation under an "all events" tariff and contributed $64.7 million of investment income to the Company.

Trans Québec & Maritimes Pipeline Inc., in which the Company has a 50% interest, contributed $10.1 million to investment income in its first full year of operations. The completion of the Trans Québec & Maritimes pipeline facilities as far as Quebec City and the construction of major new distribution laterals in Quebec, are opening up substantial new domestic markets for western Canadian natural gas, which is transported to Trans Québec & Maritimes by the Company.

Special Projects

During 1983, in co-operation with the government of Nova Scotia, the Company commenced studies of pipelines and other related facilities in Canada which will be required to move Sable Island gas to markets in Nova Scotia, New Brunswick and the United States.

As manager of the Polar Gas project, the Company plans to apply during 1984 for a new smaller pipeline project to be built down the Mackenzie River Valley initially to transport natural gas from the Mackenzie River delta to southern markets.

Under present plans, natural gas reserves from these areas could be attached to markets in the late 1980's and early 1990's.

Canada-United States Negotiations

Some progress was made during 1983 between the governments of Alberta and Canada in resolving the future course of natural gas pricing in Canada and limited progress was also made in resolving differences between the

Radcliffe R. Latimer, President and Chief Executive Officer

governments of Canada and the United States over the price of Canadian gas imported into the United States. The border price for natural gas exports was lowered from (U.S.) $4.94 to (U.S.) $4.40 per MMBtu and subsequently, under a new incentive pricing system, it was agreed that United States customers would pay (U.S.) $4.40 per MMBtu for the first 50% of their contract volumes and (U.S.) $3.40 per MMBtu for the balance. The objective of allowing natural gas to compete freely with other forms of energy in the United States market was not attained.

Oil and Gas Division

While the investment in the Company's oil and gas exploration and development activities was lower in 1983 due to weakness in the market demand for natural gas and due to lower world oil prices, it is estimated that these expenditures will increase by about 48% to $140 million in 1984. The strong financial position of the Company will enable continuing expenditures on oil and gas exploration in the years ahead. The operator of substantially all of the Company's western Canada oil and gas properties has entered into a farmout agreement covering much of western Canada. The agreement will not reduce the Company's interest in these properties, but will accelerate exploration activity. The Company will continue to consolidate its foreign land holdings and will be participating in exploratory wells in the North Sea, Italy, Australia, and Indonesia.

Outlook for 1984

During 1983, prices for all forms of fossil energy tended to stabilize, as did interest rates. This favourable trend should continue into 1984, but the world price of oil is still subject to many stresses and any drastic change could affect both interest rates and all current energy use projections.

The improved stability in 1983 created an atmosphere more conducive to forward economic planning by Canadian and United States business, particularly in the industrial sector. Only a continuation of the economic recovery, coupled with prices competitive with other fuels used in industry, will materially improve Canadian natural gas sales in the short term.

It is becoming increasingly accepted in both Canada and the United States that governments should let the marketplace determine the price of natural gas. TransCanada has advocated and will continue to advocate that the private sector should be responsible for the negotiation of sales agreements and that such agreements should be subject to government review only after negotiation. With national elections likely to take place in 1984 in both countries, it may be too optimistic to hope for definitive political action before 1985.

The chief effect of the sales decline on the Company's operations has been to reduce and defer projected investments in new pipeline facilities by two or three years. Pipeline construction expenditures are expected at a relatively low level until 1986. Expenditures on plant, property and equipment are estimated at $64 million in 1984 as compared to $75.8 million in 1983. Major new pipeline construction, estimated to cost $2 billion, associated with increased exports of natural gas to the United States, will be deferred until 1986, at the earliest. It is expected that this investment will be spread over a period of from three to five years.

The lower requirements for investment in new pipelines will provide the Company with the opportunity over the next three years to expand into other fields. The Company anticipates it may make additional investments in 1984 and 1985 in energy-related activities, particularly in the United States, where the Company is already operating. The large United States market and favourable investment climate are significant factors in this decision.

In 1983, the Company acquired a 50% interest in a new ethane and natural gas liquids extraction plant near Empress, Alberta. The Company anticipates that the manufacturing facilities of its wholly-owned subsidiary, Cancarb Limited, which has been making significant gains in sales of thermal carbon black in southeast Asian markets, may be expanded in the last half of the decade.

The Company has entered into an agreement under which the Company will drill geothermal wells in California for steam, which will be used in the generation of electricity in California.

TransCanada anticipates that its 1984 earnings will be higher than 1983 earnings, assuming that world oil prices and interest rates remain fairly stable.

1983 Financing Activities

During 1983, the Dividend Reinvestment and Stock Dividend Plans contributed significant amounts of equity. Eight percent of common shareholders and three percent of preferred shareholders participated in these plans and contributed $9 million in new common equity. Primarily as a result of the election by BCE to join the Dividend Reinvestment Plan, it is estimated that these plans will provide more than $50 million in new equity in 1984.

In 1983, the Company sold $100 million in debentures in Canada and an additional Swiss francs 100 million in notes. Three security issues totalling the Canadian equivalent of $77.3 million were sold by one of the Company's European subsidiaries.

The association with BCE, which will reinforce the Company's existing financial strength in North American and European financial markets, was further strengthened by the appointment of Mr. R. R. Latimer, President and Chief Executive Officer of the Company, as a Director of BCE in January, 1984.

Board of Directors

Several changes occurred during 1983 in the membership of the Company's Board of Directors. Mr. John Beddome, Chairman of the Board and a Director, resigned both as Chairman and as a Director in early December, 1983, following the sale by Dome Canada of its remaining TransCanada common shares. His fellow Directors wish to record their thanks and appreciation to Mr. Beddome, particularly for his invaluable contribution in ensuring Company participation as an investor in Northern Border, Foothills (Sask.) and Trans Québec & Maritimes. Mr. W. E. Richards resigned as a Director at the same time. His fellow Directors wish to confirm their appreciation of the opportunities Mr. Richards created for the Company's diversification into oil and gas exploration and development.

On December 7, 1983, the Company was fortunate in securing the services of Mr. Allan R. Taylor, President and Chief Operating Officer of The Royal Bank of Canada and Mr. Gerald J. Maier, President and Chief Executive Officer, Bow Valley Industries Ltd., as new Directors. On your behalf, we welcome both of these gentlemen to the Board.

At the same time, Mr. Gordon P. Osler, Chairman, Stanton Pipes Limited, was elected as Chairman of the Board to succeed Mr. Beddome. Mr. Osler has been a Director of TransCanada PipeLines since 1954 and this year celebrates his 30th anniversary as a Company Director.

To succeed Mr. James W. Kerr, who has reached the mandatory age of retirement, the name of Dr. Robert J. Richardson, Executive Vice-President, E. I. DuPont de Nemours and Company, and President designate of BCE will be submitted to the shareholders at the Annual Meeting of Shareholders on May 2. If elected, Dr. Richardson will bring to TransCanada a great knowledge of oil and gas and related energy industries. Dr. Richardson is also a Director of BCE.

The Board has decided to increase the number of Directors to 16. Mr. Robert H. Knight, a senior partner of the New York law firm of Shearman & Sterling has also accepted an invitation to join the Board, subject to shareholder approval. Mr. Knight will make available to the Board his very broad experience with United States government and business.

In conclusion, may we express once again our thanks to our employees, who have made our 25th anniversary year such a success.

On behalf of the Board:

Chairman

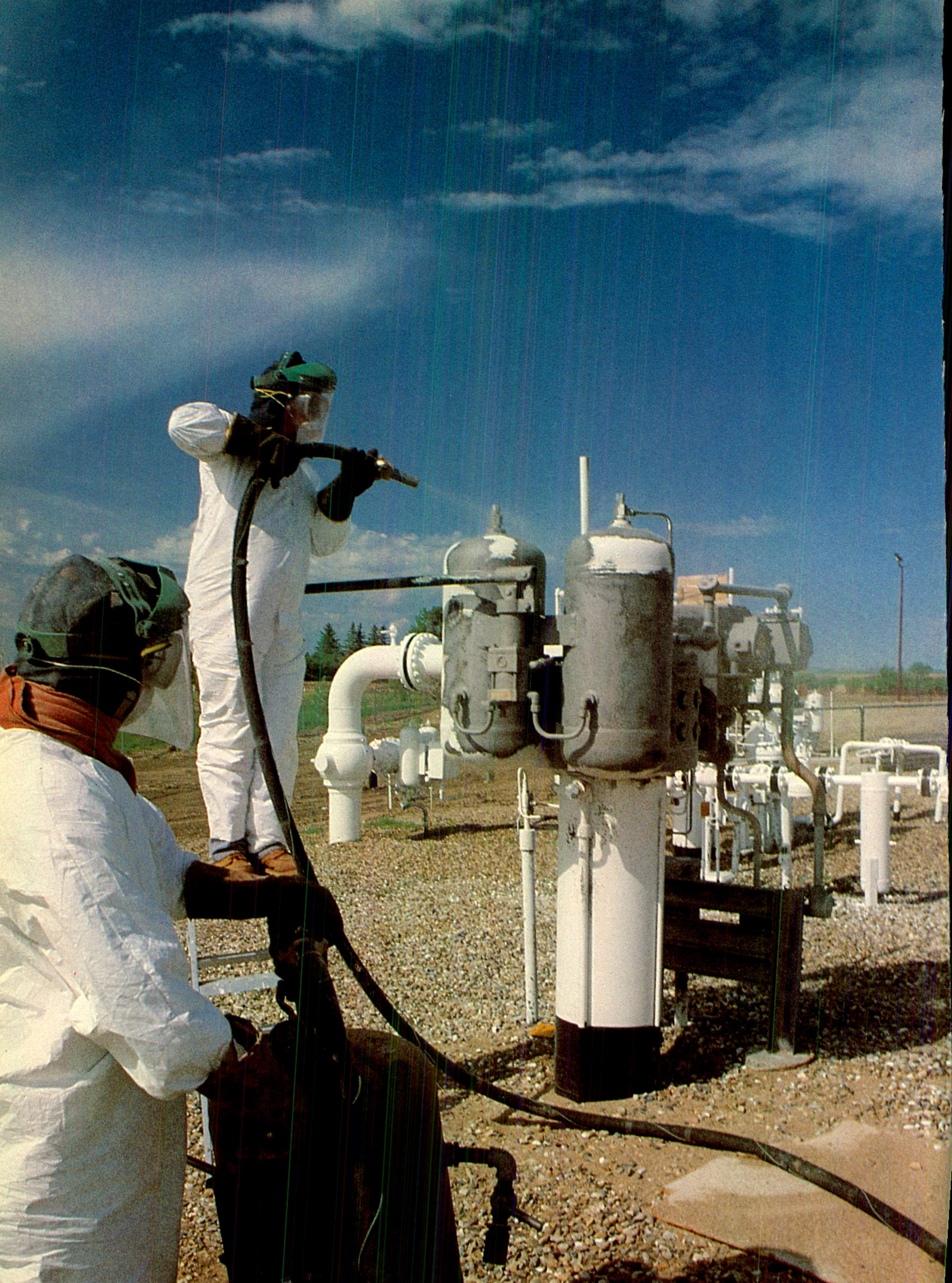
President and Chief Executive Officer

Toronto, Canada
April 3, 1984.

James W. Kerr

On May 2, 1984, Mr. James W. Kerr will be leaving the Board of Directors. Commencing in late 1958 when he became President and Chief Executive Officer of the Company, Mr. Kerr was successful in building TransCanada into a large Canadian company. He first demonstrated his leadership by securing early vital gas export contracts and in developing major Canadian suppliers for pipe, compressor engines, valves and other pipeline equipment. His dynamic sponsorship of Great Lakes Gas Transmission Company after he became Chairman, President and Chief Executive Officer, his encouragement of new pipeline technology which made TransCanada a world leader in the field, his skill in securing the financing and construction of a second loop line across northern Ontario, and his election as the first Canadian President of the world-wide International Gas Union, are only a few of the highlights of a distinguished business career.

After retiring as an officer of the Company in late 1979, Mr. Kerr continued as a Director and Consultant to the Company. His fellow Directors wish to acknowledge the unparalleled contribution he has made to TransCanada PipeLines during his years of service.



Gas Reserves

At December 31, 1983, the Company estimated that 1 424 billion cubic metres of gas reserves had been established under its contracted lands in western Canada. Contracted gas production totalled 565 billion cubic metres, including production of 29.3 billion cubic metres for the 12-month period ending December 31, 1983. Approximately 99% of the Company's contracted reserves are in Alberta, with a minor portion in Saskatchewan.

While the Company again experienced an increase in established reserves and productive capability on its contract lands, the 1983 growth rate was less than experienced in previous years. The drilling of 4,780 wells in Alberta during 1983 was essentially the same as 1982. There was a marked shift in emphasis to oil well completions, which increased by 988 wells over the 1982 level, while the completion of 1,431 gas wells represented a decrease of 957.

The Alberta Energy Resources Conservation Board in its February, 1983 report recommended the total volume, which may be removed from Alberta under the Company's major removal permit, be increased by 302 billion cubic metres to 1 136 billion cubic metres and that the permit term be extended five years to October 31, 1999. The recommendation is awaiting approval by the Alberta government. At December 31, 1983 some 495 billion cubic metres had been removed under this permit.

Take or Pay Payments

Substantially all of the Company's gas purchase contracts have provisions requiring take or pay payments by the Company when it is unable to request specified minimum annual quantities of gas for delivery. Since 1977, the strength of the Company's gas supply has been such that with the market available to it, the Company has been unable to purchase annual quantities of gas sufficient to satisfy its obligations under its gas purchase contracts. This resulted in an arrangement, (the "Topgas Program") implemented in 1982 between the Company, a consortium of Canadian and foreign banks, and substantially all of the Company's producers, which provided for the Company's future take or pay obligations being limited to 60% of the 1981/82 contract year obligation, and that Topgas Holdings Ltd. ("Topgas") acquire the Company's asset "Payments on Future Gas Supply". The Company's term bank loans incurred for this purpose were repaid. The total funds that were advanced by Topgas under the Program amounted to $2.3 billion.

The market decline in the 1982/83 contract year resulted in the Company's average level of take being 48% of the minimum annual obligation level set out in the Topgas Program, causing the Company to incur 4 812 million cubic metres of take or pay gas. Total take or pay payments due at the end of 1983 for the 1982/83 contract year amounted to approximately $360 million.

The Company proposed and, with the co-operation of its producers, implemented a further program, "Topgas Two", which is similar to the Topgas Program and reduces the future take or pay obligation to a level derived from a formula that is based on the level of take for the two preceding years, subject to a minimum of 50% of the 1981/82 contract year obligation. At end of March 1984, producers representing approximately 90% of the Company's contracted supply had participated in the Topgas Two program and had received $310 million under the program for the take or pay incurred in 1983. The outstanding balance of the take or pay payments made by the Company as at the end of March 1984 was $50 million. The Company expects that the majority of the producers by volume will join the program in 1984 and that the payments made by the Company will be refunded. The recovery period under both the Topgas and Topgas Two Programs is a maximum term of 10 years, commencing November 1, 1984.

The carrying costs associated with the funds advanced to the producers by Topgas, Topgas Two and the Company will be recovered through the Company's Alberta cost of service.

Left: Sandblasting valves before painting. Station 9, Herbert, Saskatchewan.

On October 10,1983, TransCanada completed 25 years of successful operation.

As the Company's operations have changed over the years, TransCanada's people have accepted and met the challenge. As the Company expands into new areas, new employees with new skills are joining us.

In this Annual Report, we are saluting all our employees for their contribution.

Conversion from metric

TransCanada reports its operations in the International System of Units (SI). To convert the metric terms shown in this report to the English system of units, the following list of simplified, approximate conversion factors is given:

To Convert	To	Multiply by
thousands of cubic metres of gas (10^3m^3)	thousands of cubic feet of gas (Mcf)	35.3
cubic metres of oil (m^3)	barrels of oil (bbls)	6.29
kilometres (km)	miles (mi.)	0.62
millimetres (mm)	inches (in.)	0.04
square kilometres (km^2)	acres	247.1
tonnes (t)	tons (short)	1.10
gigajoules (GJ)	millions of British thermal units (MMBtu)	0.95
kilowatts (kW)	Horsepower (HP)	1.34
kilopascals (kPa)	pounds per square inch (psi)	0.15


3650

Canadian Operations/Pipeline Division

Left: Night shift maintenance on a bulldozer. Station 58, Ignace, Ontario.

Marketing

1983 Performance

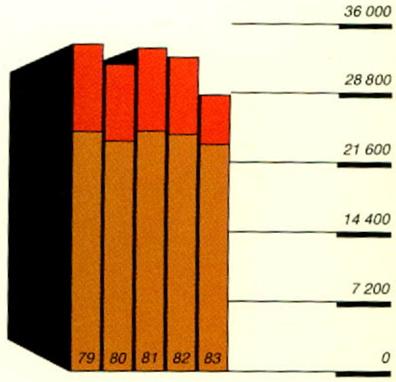
Gas sales and transportation deliveries in 1983 were greatly influenced by warmer than normal weather and by the economic recession in Canada and the United States. In 1983, the Company's total sales and transportation deliveries were 12% below 1982 levels. However, sales in the last half of 1983 in both Canadian and U.S. markets increased from the levels experienced during the early part of the year.

The Company's Canadian and export deliveries were 5% higher in the last quarter of 1983 than in the corresponding period in 1982. Deliveries during December 1983 were higher than for any month since January 1982. In the first quarter of 1984, sales and transportation volumes increased by 1 620 million cubic metres, or 20% higher than the first quarter of 1983. A revival of industrial sales in the Canadian market which started in mid-1983, continued strongly into 1984.

Marketing Initiatives in Canada

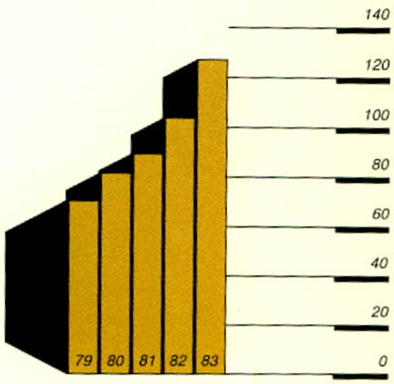
The Company participated in a number of marketing initiatives during 1983 which will provide the framework for increased natural gas sales in both Canada and the United States.

The Company, in co-operation with its Canadian distribution customers, is aggressively promoting natural gas use. During 1983, the Company financially supported advertising campaigns in Manitoba, Ontario and Quebec beyond those undertaken solely by the distributors. These programs promoted an awareness of the benefits of using natural gas. The Company intends to pursue similar advertising programs in 1984.

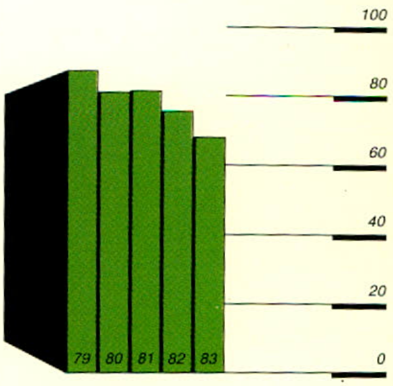


Gas delivered for sales and transportation
Millions of cubic metres

Canadian
Export



Average price Canadian sales
Dollars per thousand cubic metres



Average daily sales
Millions of cubic metres

Annual Gas Sales and Transportation Volumes
in thousands of cubic metres

Sales	**1983**	1982	1981	1980	1979
Saskatchewan Power Corporation	**35 884**	57 310	35 560	166 706	444 824
Plains-Western Gas (Manitoba) Ltd.	**329 017**	296 967	238 243	251 994	260 014
Inter-City Gas Corporation	**225 951**	239 825	216 440	238 057	250 637
Greater Winnipeg Gas Company	**1 283 129**	1 362 133	1 332 688	1 413 725	1 508 782
Northern and Central Gas Corporation Ltd.	**2 975 668**	3 029 432	3 449 209	3 483 152	3 546 983
The Consumers' Gas Company Ltd.	**7 543 916**	8 170 197	8 247 993	8 025 751	8 151 365
Union Gas Limited	**6 533 808**	7 276 464	7 141 439	6 407 173	6 840 115
Kingston Public Utilities Commission	**81 601**	76 101	84 933	79 813	74 731
Gaz Métropolitain, inc.	**2 901 359**	2 485 354	2 622 884	2 330 752	2 220 273
Trans Québec & Maritimes Pipeline Inc.	**51 891**	379	—	—	—
Total Canadian	**21 962 224**	22 994 162	23 369 389	22 397 123	23 297 724
Michigan Wisconsin Pipe Line Company	**178 111**	200 003	372 997	383 020	516 986
Midwestern Gas Transmission Company	**1 046 754**	1 583 241	2 868 160	3 713 995	4 273 792
Great Lakes Gas Transmission Company	**1 243 027**	2 437 712	2 616 861	2 663 417	3 206 072
Inter-City Gas Limited	**159 652**	143 755	157 585	169 441	188 078
Niagara Gas Transmission Limited	**180 392**	157 288	179 699	183 003	186 033
Vermont Gas Systems, Inc.	**130 590**	128 009	130 001	119 566	128 740
Additional Exports	**—**	—	—	—	60 174
Total U.S. Export	**2 938 526**	4 650 008	6 325 303	7 232 442	8 559 875
Total Sales	**24 900 750**	27 644 170	29 694 692	29 629 565	31 857 599
Transportation	**3 675 666**	4 852 478	3 753 127	2 167 927	1 994 348

Under the Canadian government's Distribution System Expansion Program, the Company's Canadian distribution customers expect to add more than 26,000 new natural gas customers over the next three years by expanding their distribution networks. In addition, there were more than 36,000 conversions from oil to natural gas in 1983. These new customers will add approximately 500 million cubic metres of natural gas sales each year. The Company added six new delivery points to facilitate service to communities receiving natural gas for the first time.

In Quebec, natural gas service to Québec City through the extended Trans Québec & Maritimes Pipeline Inc. ("TQM") system commenced in September 1983. By year end, natural gas became available in the Eastern Township areas. As a result of these expansions, the Company's daily contracted quantity increased by one million cubic metres. In addition, Gaz Inter-Cité Québec announced that its distribution system will be extended during 1984 and 1985 to serve more communities in its franchise area.

During 1983, the Company was involved in two major initiatives to resolve the problem of surplus heavy fuel oil in eastern Canada. At a National Energy Board ("NEB") inquiry, the Company urged that imports of heavy fuel oil not be permitted where they impede penetration of natural gas. The Company also participated in an Industry Task Force which recommended that imports be reduced by using the equivalent of the subsidy on imported heavy fuel oil to lower the costs of transporting domestic heavy fuel oil to non-gas service areas.

Domestic Natural Gas Pricing

On June 30, 1983, the governments of Alberta and Canada amended the 1981 Energy Pricing Agreement, resulting in a stable wholesale price for natural gas until at least February 1985. The amendment also confirmed the Federal government's commitment to maintain the wholesale price of natural gas in eastern Canada at 65% of the price of crude oil.

This stability in wholesale natural gas prices will help natural gas to maintain its price advantage over oil and increase its price advantage over electricity. Assurance of price stability will assist gas marketing efforts.

Natural Gas For Vehicles

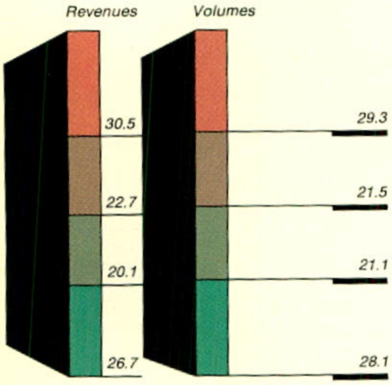
The use of natural gas to displace gasoline as a transportation fuel has opened up an important future market for natural gas in Canada and the United States. Federal and provincial government incentive programs and marketing initiatives by the natural gas industry have combined to establish natural gas as a viable, safe and economical motor vehicle fuel. Several public and private fuelling stations have opened, mainly in the larger urban areas in Canada.

The Company is participating in the development and promotion of natural gas as a vehicle fuel through its involvement with industry groups and through the funding of research and development projects. In addition, the Company has converted a number of Company vehicles to operate on natural gas.

Natural Gas Exports

The combination of recession, a warmer than normal winter, excess deliverability of U.S. natural gas and the high relative price of Canadian gas resulted in lower than usual export deliveries during 1983. While export sales and transportation deliveries declined by more than one-third from 1982 levels, indications are that export deliveries will increase in 1984 and beyond. During the last quarter of 1983, export deliveries were 13% higher than the corresponding period of 1982.

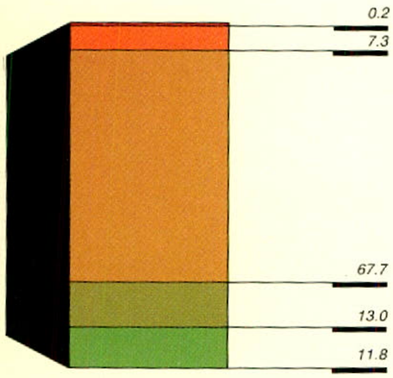
In April 1983, the Federal government reduced the export price of natural gas by 11% to (U.S.) $4.40 per MMBtu. In July 1983, a Volume-Related Incentive Pricing Plan was introduced, whereby U.S. natural gas importers could benefit from a further reduction of 23% to (U.S.) $3.40 per MMBtu for volumes purchased in excess of 50% of the licenced quantity.



Distribution of sales revenues and volumes

Percentage by calendar quarter

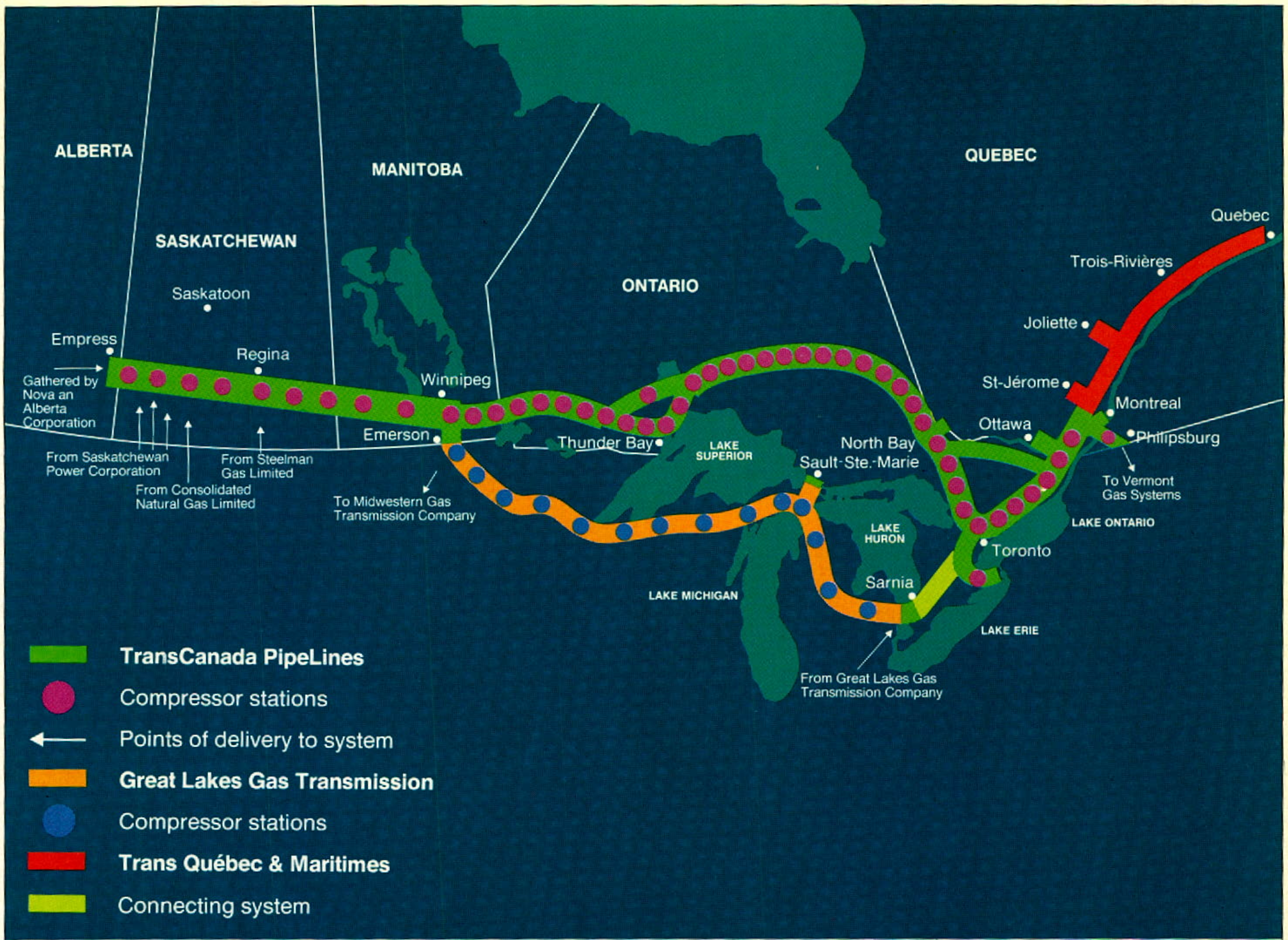
First quarter
Second quarter
Third quarter
Fourth quarter



Where the gas was sold in 1983

Percentage of volume sales

Saskatchewan
Manitoba
Ontario
Quebec
Export

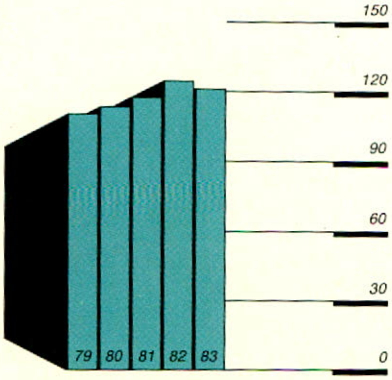

ALBERTA
SASKATCHEWAN
MANITOBA
ONTARIO
QUEBEC
Saskatoon
Empress
Regina
Winnipeg
Emerson
Thunder Bay
LAKE SUPERIOR
North Bay
Sault-Ste.-Marie
LAKE HURON
LAKE MICHIGAN
Sarnia
Toronto
LAKE ONTARIO
LAKE ERIE
Ottawa
Montreal
Philipsburg
St-Jérome
Joliette
Trois-Rivières
Quebec
Gathered by Nova an Alberta Corporation
From Saskatchewan Power Corporation
From Consolidated Natural Gas Limited
From Steelman Gas Limited
To Midwestern Gas Transmission Company
From Great Lakes Gas Transmission Company
To Vermont Gas Systems
TransCanada PipeLines
Compressor stations
Points of delivery to system
Great Lakes Gas Transmission
Compressor stations
Trans Québec & Maritimes
Connecting system


Gaz Inter-Cité Québec Inc.
GICQ Constructed
GICQ 1985 Construction
Trans Québec & Maritimes
TransCanada PipeLines
Jonquière
La Baie
La Tuque
QUEBEC
Québec
Trois-Rivières
Louiseville
Bécancour
Joliette
Drummondville
Asbestos
St-Jérôme
Granby
Sherbrooke
Montreal
Waterloo
Ottawa
ONTARIO
UNITED STATES

Left: *Installing a new silencer to reduce engine noise. Station 130, Maple, Ontario.*

Top: *Natural gas pump for automobiles and commercial vehicles.*

Bottom: *Forging furnace at Hayes Dana's St. Catharines Plant, using natural gas.*



Maximum day gas delivered for sales and transportation

Millions of cubic metres

While these pricing initiatives are steps in the right direction, the Company believes that Canada must move to a market-oriented export pricing system if the potential for export sales is to be realized. The Company is currently working with a Federal/Provincial task force to develop new natural gas export pricing policies to take effect November 1, 1984.

As a result of temporary marketing problems, some of the Company's United States customers were not able to purchase the minimum volumes specified in their contracts and incurred "take or pay" liabilities. In recognition of these problems, the Company negotiated amendments to its export sales contracts with all of its major U.S. customers. Under these amendments, the customers are obligated to purchase at least 50% of their contracted volumes for the next two years. Since these customers took less than 50% of the contracted volumes during 1983, the amendments are expected to result in increased export sales during 1984.

Additional Export Sales

In January 1983, the Canadian government authorized the Company to export significant additional gas sales, mainly to the U.S. northeast, subject to the receipt of suitable U.S. authorizations and to the construction of the necessary transmission facilities. Some U.S. authorizations were received during 1983 and hearings began on others.

A significant breakthrough was achieved in new exports to the United States early in 1984 following final U.S. authorizations for the sale of 113 thousand cubic metres per day at Niagara Falls, Ontario to Boundary Gas Inc. of Boston. The northeastern United States will be the first market to feel the pinch of declining deliverability and the sale to Boundary represented only the start of developing this important new market. The Company expects to begin delivering the volumes in November 1984.

During 1983, the Company initiated studies to determine the most economical route for transporting the remainder of the newly approved exports. The Company expects to complete these studies early in 1984. An application to the NEB to construct the necessary facilities will be filed shortly thereafter.

1983 Toll Decision

The NEB adjusted the Company's transportation tolls effective August 1, 1983. The new tolls reflect a 14.00% rate of return on rate base. This compares with a previously authorized rate of return of 13.88%.

In support of the Canadian government's price restraint program and in order to limit increases in its proposed tolls, the Company applied for a deferral of recovery of a portion of return and associated income taxes with respect to the North Bay Shortcut facilities. The NEB accepted the Company's deferral concept and has allowed a total deferral of $45.6 million, which, along with carrying costs, will be amortized into future tolls over a three-year period commencing August 1, 1984.

The new tolls set August 1, 1983 were, on average, 5% higher than the tolls previously in place.

1984 Toll Application

In January 1984, the Company applied to the NEB for new transportation tolls to be effective August 1, 1984. The requested tolls reflect an increase in the Company's rate of return on equity from 15% to 16¼%.

One of the Company's objectives in determining new tolls has been to restrain cost increases at levels below the current level of inflation. In its application, the Company has proposed to refund a portion of its deferred tax balance in order to keep the requested increase in tolls equal to the guideline of 4% established by the Canadian government. The Company's new tolls to the Eastern Rate Zone would result, if approved, in a 4% increase over those in place February 1, 1984.

In the Energy Pricing amendment of June 30, 1983, the Canadian and Alberta governments agreed that increases in the Company's tolls of more than 5% above tolls in effect July, 1983 would be subsidized by the Canadian government. Since the Company's tolls, effective February 1, 1984, are slightly greater than 5%, the Canadian government will subsidize eastern Canadian distributors for any such excess subsequent to February 1, 1984 until the expiration of the subsidy period of the June 30, 1983 agreement on January 31, 1985.

1983 Construction

After three years of heavy construction, 1983 was a year of consolidation. The capital expenditure program of $75.8 million included the final clean-up and restoration of the right-of-way of the North Bay Shortcut and the Saskatchewan and Manitoba loop line, which was placed in service in 1982. The ongoing programs of modification and upgrading of existing plant and pipeline facilities to maintain safe and efficient operation of the system, included pipe replacements at 147 locations across the TransCanada system, totalling 13.9 km. Many of the smaller construction and maintenance projects were carried out by TransCanada's experienced construction and operations personnel.

New delivery points were established at Lowther, Val Gagne, Brighton, Sabrevois, Beauharnois and Vaudreuil to meet the requirements of new markets in Ontario and Quebec.

1983 Operations

In 1983, the continuing program of ensuring that the pipeline is adequately protected against corrosion included the inspection of 4 700 kilometres of pipe and completion of the necessary remedial work. A total of 566 kilometres of pipe was internally inspected for dents and other deformation using the Company's electronic inspection tools. The Company's high standards of gas conservation and operating efficiency were maintained by regular performance testing of compression equipment and by plant modifications.

The commencement of operation of the North Bay Shortcut in December 1982, increased both the capability and supply to the eastern Canadian markets, which reached new peaks in December 1983.

New Technology

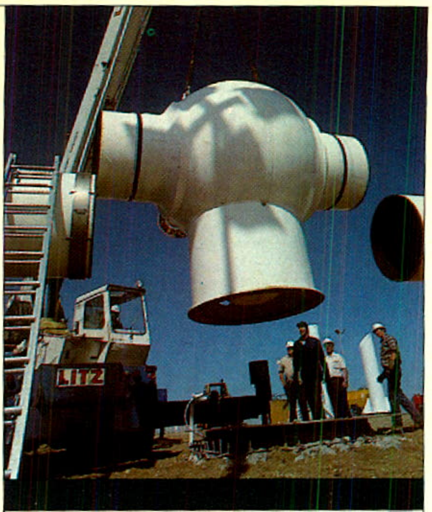
The Company made several notable technical achievements during the year.

A new electronic inspection tool, designed to detect external corrosion of buried pipe, has undergone successful preliminary testing. This electronic inspection tool will now join the Company's inventory of similar tools for the detection of mechanical and metallurgical flaws, which are in regular use to ensure that the pipeline system operates safely and efficiently.

Advancement in minicomputer technology enabled a major upgrading of the Company's gas control system. In addition to cost savings, the use of minicomputers has resulted in faster response times, increased data availability and improved system flexibility.

1984 Construction

A construction program of $64.0 million is planned for 1984. This program includes the replacement of 9.5 km of the Emerson line, the utilization of new high impact welding technology on the construction of 6.2 km of loop line in northern Ontario and the continuation of the Company's program of modification and upgrading of existing plant and pipeline facilities to maintain safe and efficient operation of the system.



Right: Installation of new pipeline strainer. Station 17, Regina, Saskatchewan.
Top: Pipeline strainer removal.
Bottom: Ultrasonic testing of pipe.


LITZ
CRANE RENTALS
LITZ

Canadian Operations/Pipeline Investments

Trans Québec & Maritimes Pipeline Inc. (TQM)

In August 1983, the extension of the TQM pipeline system from Trois-Rivières to Québec City was completed and deliveries commenced in September. During October and November, Gaz Inter-Cité Québec ("GICQ"), placed in service laterals to serve Bécancour and Shawinigan/Grand-Mère from TQM's pipeline and also constructed a lateral to serve communities as far east as Sherbrooke in the Eastern Townships from TransCanada's pipeline system.

While the displacement of heavy fuel oil in the industrial sector has been slower than expected in new markets in Quebec, there were significant breakthroughs in 1983 in selling gas to large industrial customers in both the new areas served by GICQ and the expansion areas served by Gaz Métropolitain.

The rationalization of refining capacity in the Province of Quebec is making less heavy fuel oil available in the industrial markets and there is a great potential for natural gas sales as a result. Natural gas is facing increasing competition from electricity in residential heating markets.

For the first full contract year 1982/1983, TQM's total sales in the Quebec expansion markets totalled 28.1 million cubic metres. These lower than expected sales are mainly due to the lack of success in displacing heavy fuel oil in the industrial sector and partly as the result of the strong competition from Hydro-Québec's surplus electricity.

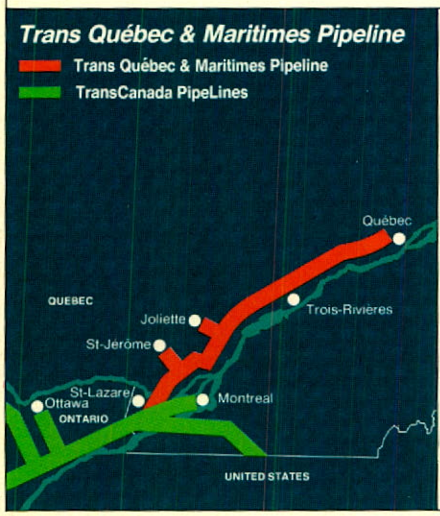
Foothills Pipe Lines (Sask.) Ltd.

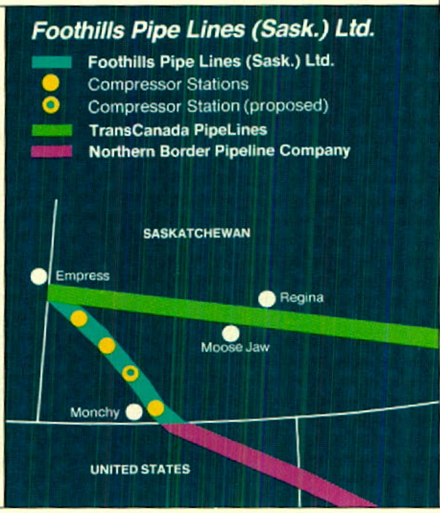
The Company owns a 44% interest in Foothills Pipe Lines (Sask.) Ltd., a 257 kilometre pipeline built across southwestern Saskatchewan to connect with the Northern Border pipeline near Monchy, Saskatchewan. The Company operates this pipeline on behalf of Foothills Pipe Lines (Sask.) Ltd.

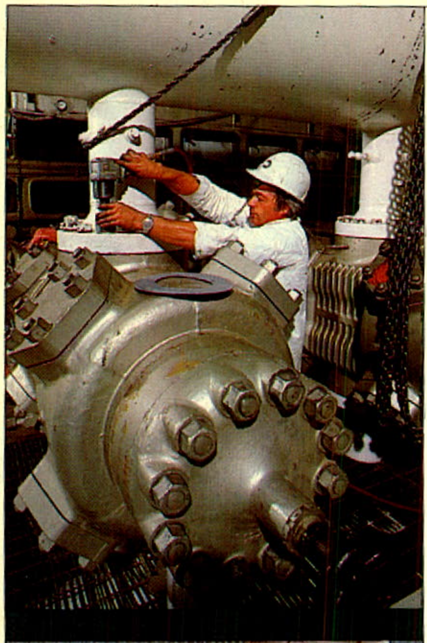
Right: Welder making a connection on 406 mm pipe replacement, TQM line near St. Lazare, Quebec.

Top: Summer student mowing the lawn at Senneville sales meter station near Montreal.

Bottom: Shoring up the walls for pipe replacement at the Soulange canal crossing.







Right: A subsoiler reconditioning farmland to a depth of one metre or more along a pipeline right of way.

Top: Overhauling a reciprocating compressor. Station 13, Caron, Saskatchewan.

Bottom: Summer student cleaning compressor. Station 802, Candiac, Quebec.

Canadian Operations/Special Projects

Sable Gas Systems Limited

In May of 1983, TransCanada PipeLines and Nova Scotia Resources Limited, a Nova Scotia Crown corporation, established Sable Gas Systems Limited. The new company was given a mandate to design, build, own and operate natural gas transmission facilities from the Nova Scotia offshore through Nova Scotia and New Brunswick to the United States border. TransCanada PipeLines is manager of Sable Gas Systems. The Province of Nova Scotia has the option to acquire up to 50% of any Nova Scotian hydrocarbon transmission facilities from offshore through the province. The option was provided to Nova Scotia as part of the Canada-Nova Scotia agreement covering offshore hydrocarbon development.

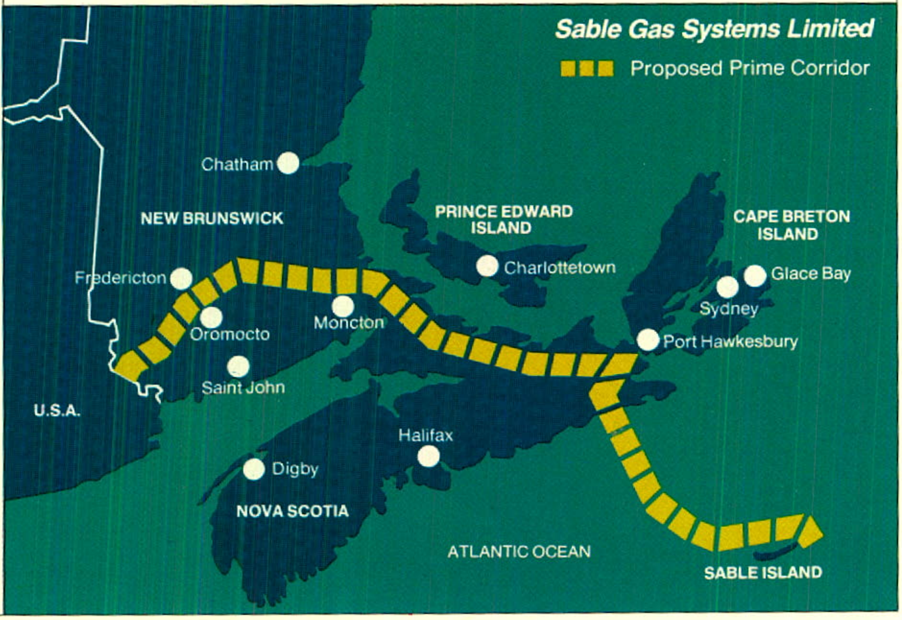
It is anticipated that the various producers of the Venture structure near Sable Island, will file an export application with the NEB during 1984. Sable Gas Systems will follow immediately with a facilities application.

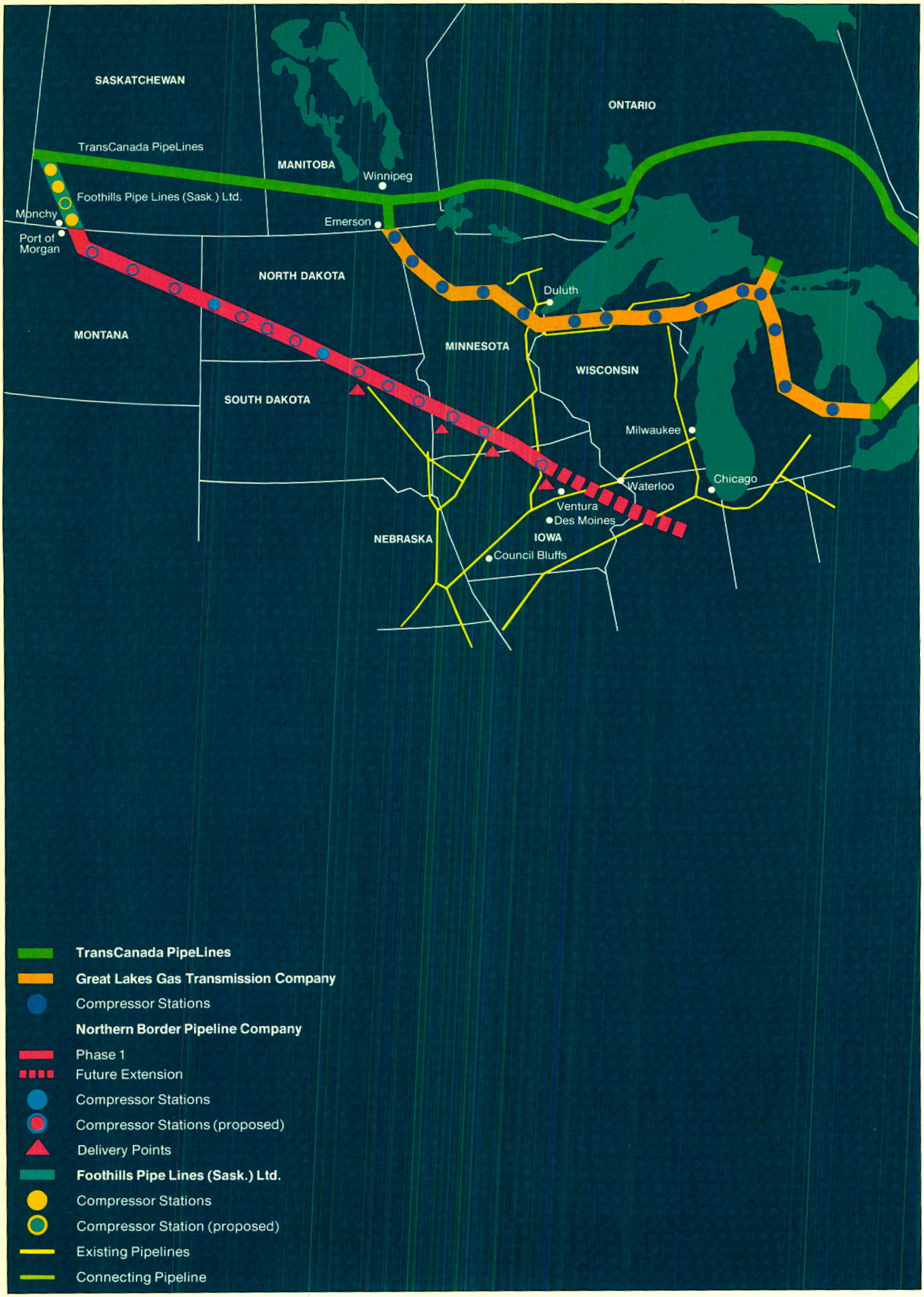
Polar Gas Project

The participants in the Polar Gas Project, of which the Company is manager, have indicated their intention to file by mid-1984 an application to construct a pipeline through the Mackenzie River Valley initially to connect gas reserves in the Mackenzie River delta to southern markets in the early 1990's.

King Christian Island LNG Project

Discussions continue between a group of major west European utilities, Petro-Canada and the Company, regarding development of a project to move liquefied natural gas ("LNG") by icebreaking LNG carriers from the Arctic Islands areas to markets in western Europe. No immediate new developments are expected in this long term project.




SASKATCHEWAN
MANITOBA
ONTARIO
TransCanada PipeLines
Winnipeg
Foothills Pipe Lines (Sask.) Ltd.
Monchy
Port of Morgan
Emerson
NORTH DAKOTA
Duluth
MONTANA
MINNESOTA
WISCONSIN
SOUTH DAKOTA
Milwaukee
Waterloo
Chicago
Ventura
Des Moines
NEBRASKA
IOWA
Council Bluffs
TransCanada PipeLines
Great Lakes Gas Transmission Company
Compressor Stations
Northern Border Pipeline Company
Phase 1
Future Extension
Compressor Stations
Compressor Stations (proposed)
Delivery Points
Foothills Pipe Lines (Sask.) Ltd.
Compressor Stations
Compressor Station (proposed)
Existing Pipelines
Connecting Pipeline

Great Lakes Gas Transmission Company

TransCanada PipeLines owns a 50% interest in Great Lakes Gas Transmission Company ("Great Lakes"), which operates a pipeline from the international boundary near Emerson, Manitoba, across the States of Minnesota, Wisconsin and Michigan, to points on the international boundary near Sault Ste. Marie and Sarnia, Ontario. The Great Lakes pipeline system consists of 2 100 kilometres of pipe and a total of 279 000 kilowatts installed at 14 compressor stations.

Great Lakes' 1983 operations resulted in net income of (U.S.) $17.5 million. This net income compares with (U.S.) $25.0 million in 1982. Great Lakes delivered for transportation or sale a total of 9.73 billion cubic metres of gas, of which 6.18 billion cubic metres, or 64%, was redelivered to the Company for sale in eastern Canada, with the balance, 3.55 billion cubic metres, delivered to Great Lakes' customers in the United States.

New rates became effective July 1, 1983, as a result of a settlement agreement reached with all parties in a 1982 general rate application. Further adjustments in rates to customers became effective January 1, 1984, resulting from a Federal Energy Regulatory Commission order on rate design issues which has been pending for some time.

TransCanada Border PipeLine Ltd.

Through its wholly-owned subsidiary, TransCanada Border PipeLine Ltd., the Company owns a 30% partnership interest in the First Phase of the Northern Border Pipeline Company, which extends 1 323 kilometres from Monchy, Saskatchewan, to Ventura, Iowa. Northern Border forms part of the eastern leg of the Alaska Natural Gas Transportation System ("ANGTS") and is intended initially to transport natural gas produced in Alberta and ultimately to transport Alaska natural gas to the mid western and eastern regions of the United States.

The Company has the right to acquire at least a 17½% partnership interest in the Second Phase. The Second Phase contemplates the extension of the pipeline from Ventura to Dwight, Illinois. However, Northern Border now plans to file an application with the Federal Energy Regulatory Commission ("FERC") to construct an extension of its pipeline from Ventura to Sandwich, Illinois, a distance of approximately 467 kilometres. This filing will be associated with a filing by ANR Pipeline Company and Northern Natural Gas Company for the construction of facilities from Sandwich to Clinton County, Pennsylvania. Under these proposed new plans the Company expects to acquire a 30% partnership interest in Northern Border's new facilities.

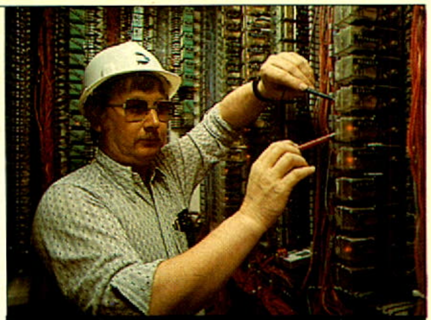
A full cost of service tariff was in effect during 1983. The requirements of the separate shippers has resulted in a substantial decrease in the volumes anticipated and on March 8, 1984 Northern Border filed with the FERC a request to reduce its transportation charges to its shippers for the first ten months of 1984 with a recoupment of this reduction by October 31, 1988.

TransCanada PipeLine Alaska Ltd.

Through its wholly-owned subsidiary, TransCanada PipeLine Alaska Ltd., the Company expects to acquire a 7% partnership interest in the Alaska segment of ANGTS. The Company's interest in the partnership may be adjusted, depending on final financing for the project.

In testimony before a U.S. Senate Committee in November 1983, the Chairman of the partnership for the Alaska segment stated that the earliest gas will flow is during the year 1990. The ultimate realization of the Company's investment in the Alaska segment is dependent upon final governmental and regulatory authorizations and cost approvals, satisfactory gas purchase, sale and transportation contracts, adequate financing and successful completion of construction.

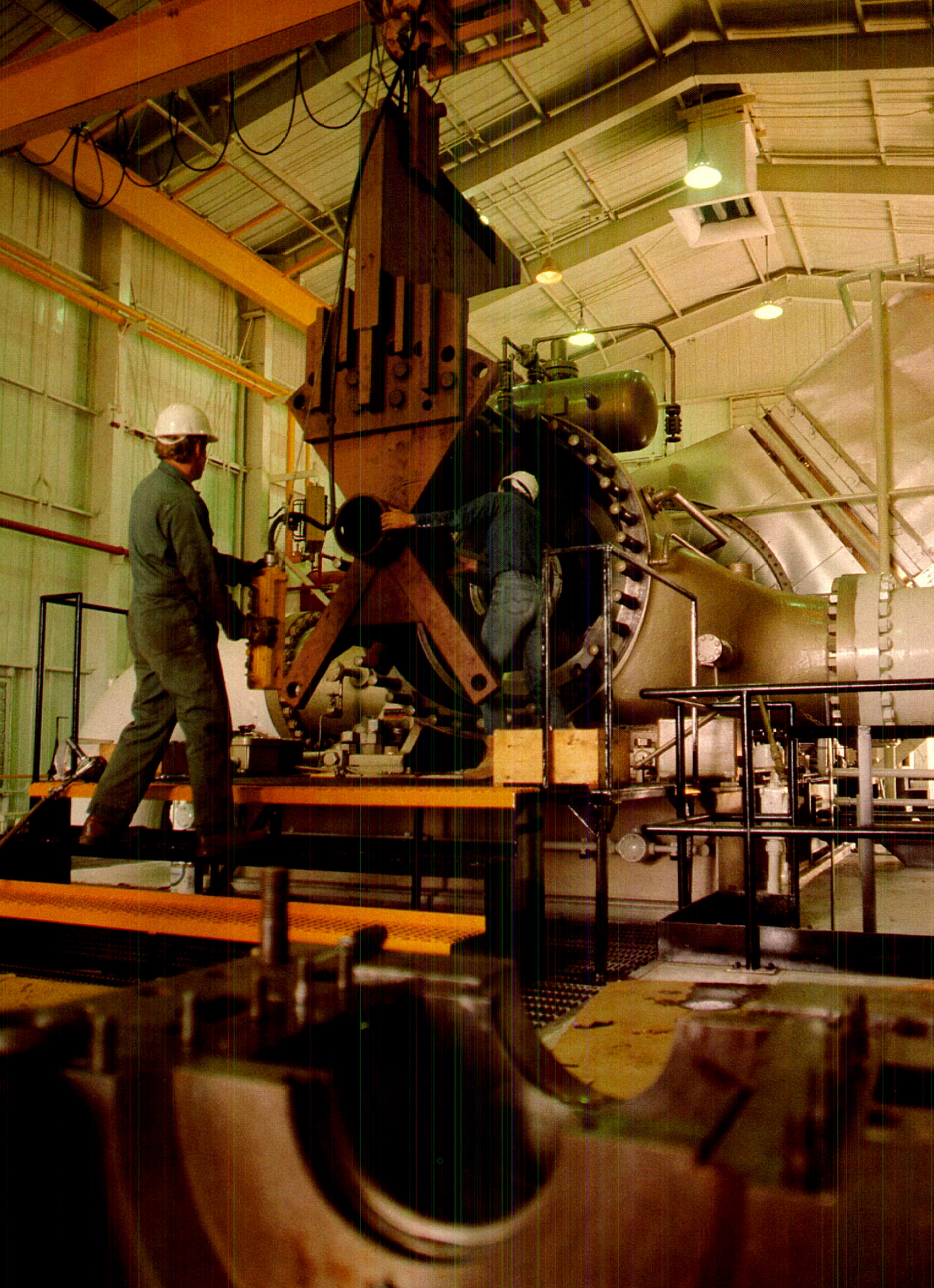
At the end of 1983, the Company had made cash expenditures of approximately (U.S.) $19.4 million in the Alaska segment.



Top: Testing new graphic control panel. Station 21, Grenfell, Saskatchewan.

Middle: Fire fighting school. Station 130, Maple, Ontario.

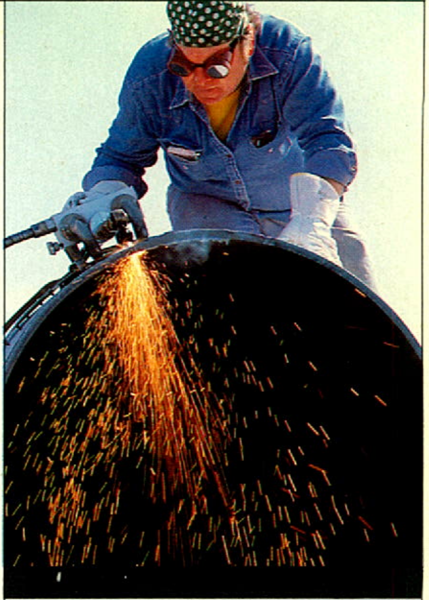
Bottom: Calibration of control system. Station 69, Eagle Head, Ontario.

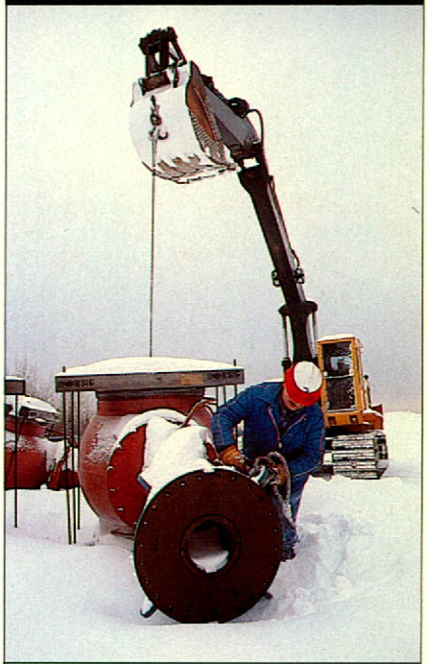


Geothermal
In March 1984, the Company, through its wholly-owned subsidiary TCPL Geothermal Ltd., entered into a formal agreement under which the Company will explore and develop lands in California. Drilling of the first joint venture well to produce steam for resale to electrical utilities commenced in March.

Niagara Interstate Pipeline System
When gas export contracts, which have already been approved by the NEB, are also approved by United States regulatory authorities, the Company will be a participant in the construction of a 259 kilometre large diameter pipeline from a point on the international boundary at Niagara Falls, New York, to the Leidy natural gas storage field near Tamarack, Pennsylvania.

Connecting United States Facilities — Sable Island Gas
When export of natural gas from the Sable Island gas reserves is fully approved, the Company has agreed in principle to participate in the construction of new United States transmission facilities from the international boundary between Maine and New Brunswick to connecting United States pipeline systems.

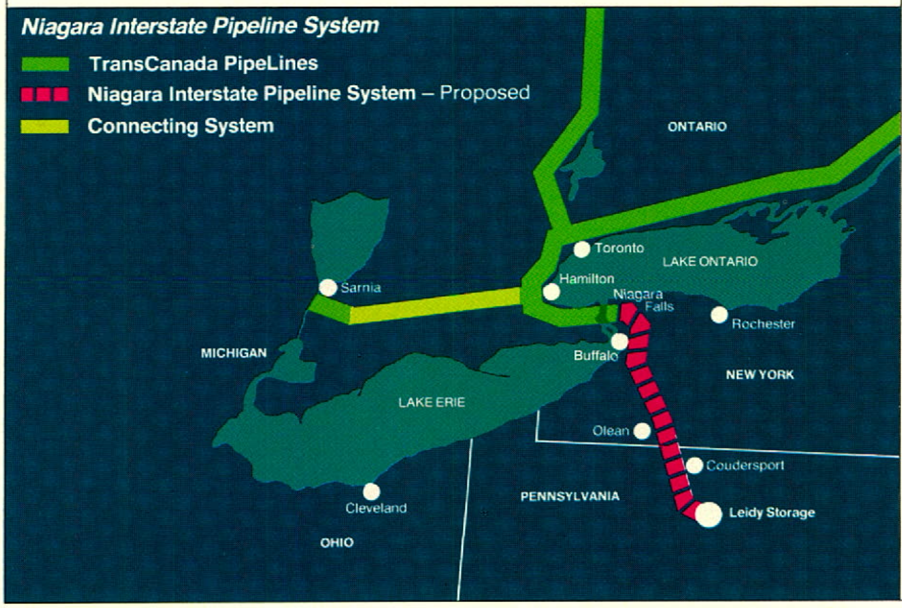


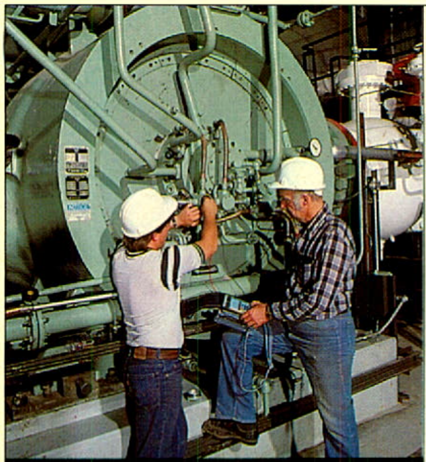


Left: Overhaul of natural gas compressor. Station 123, Bracebridge, Ontario.

Top: Welder trimming 1 219 mm pipe.

Bottom: Preparing to lift a 914 mm ball valve. Station 116, North Bay, Ontario.





Right: Technician inspecting orifice plate at Brazeau Gas Plant, Alberta.

Top: Inspection of vibration monitoring equipment. Foothills (Sask.) Station 392, Piapot, Saskatchewan.

Bottom: Pulling pipe on a drilling rig in Garrington area, Alberta.

Oil and Gas Division

Highlights

	1983	1982
Financial (in millions of dollars)		
Investment in oil and gas properties	1,336.9	1,290.7
Revenues	214.2	189.6
Operating		
Oil and natural gas liquids sales *(thousands of cubic metres)	795.5	763.9
Natural gas sales *(millions of cubic metres)	673.7	687.8

Oil and Gas Operations

Summary

The year 1983 saw the Company undergo significant organizational changes with respect to its domestic and international oil and gas operations. During the year the Company established exploration and production departments in Canada and the United States to administer oil and gas interests owned outside of its joint venture interests with Dome Petroleum Limited ("Dome") and Dome Petroleum Corp.

During 1983, the first full year of operations since the acquisition of the Hudson's Bay Oil and Gas Company Limited ("HBOG") properties, the Company participated in the drilling of 293 exploratory and 677 development wells. In addition 94 wells were drilled on the Company's land at no cost to the Company as a result of farmout agreements with other companies. Of the 970 wells drilled by the Company, 810 were located in western Canada, 122 in Indonesia, 33 in the United States and 5 in other foreign areas.

Sales volumes in 1983 averaged 2 179 cubic metres of crude oil and natural gas liquids per day, and 1.845 million cubic metres of natural gas per day.

The Company's remaining established oil and natural gas reserves at December 31, 1983 were 12.531 million cubic metres of oil and natural gas liquids and 25.295 billion cubic metres of natural gas.

At year end the Company held oil and gas interests in 266 070 km^2 netting 14 650 km^2. On a net basis, 71% were located in Canada, 7% in the United States, and the remaining 22% outside North America in Indonesia, Australia, Italy, the North Sea and Egypt. The Company's total net land holdings at December 31, 1983 decreased by approximately 25% from year end 1982 levels with the major decrease occurring in the Company's international holdings.

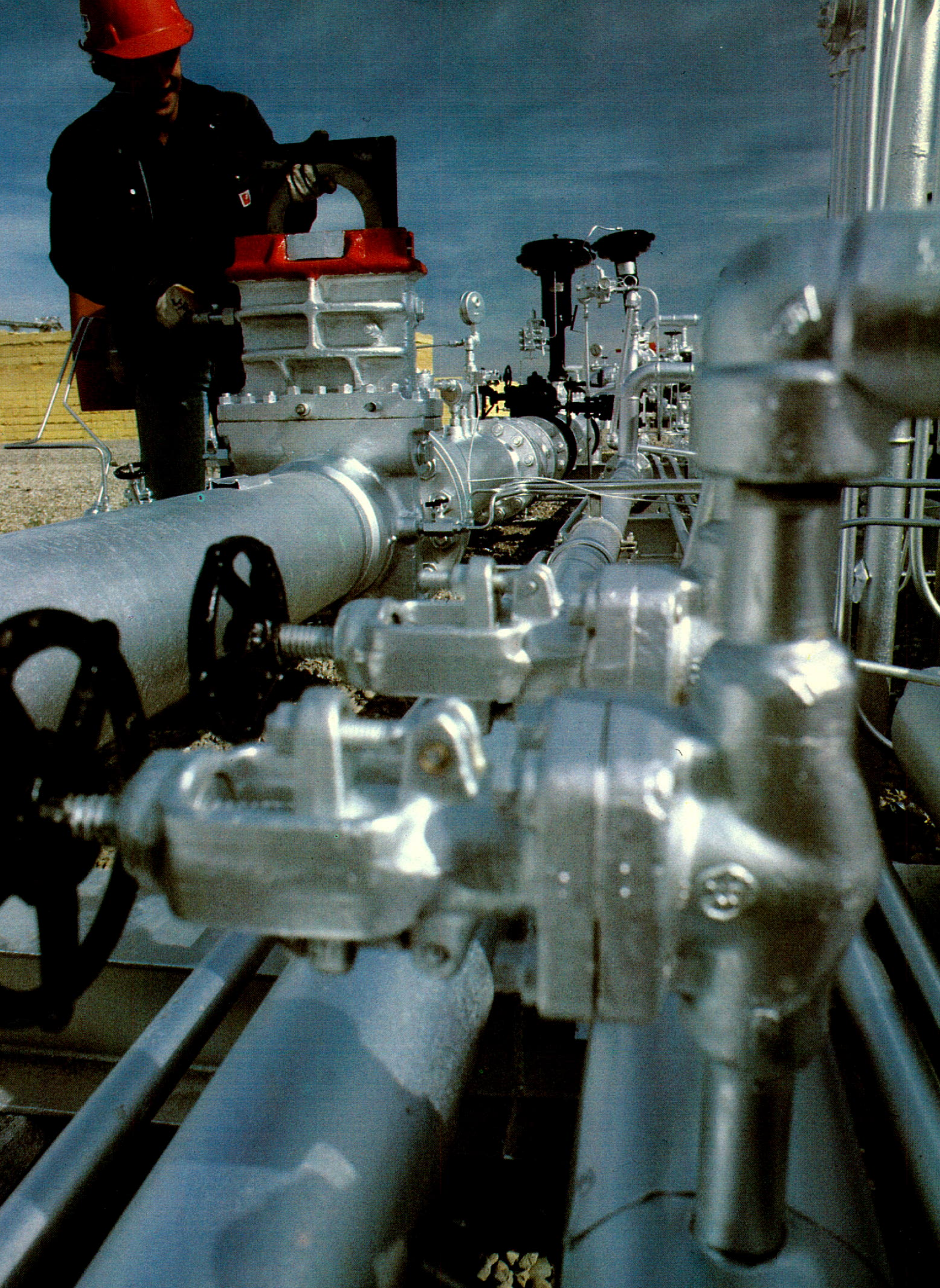
Costs incurred in oil and gas property acquisition exploration and development activities:

	Property Acquisition	Exploration	Development	Total
		(millions of dollars)		
During 1983				
Canada	—	31.3	29.2	60.5
United States	2.2	10.0	5.8	18.0
Other Foreign	—	8.8	7.0	15.8
Total	2.2	50.1	42.0	94.3
During 1982				
Canada	482.8	26.7	20.0	529.5
United States	21.7	9.3	6.7	37.7
Other Foreign	55.5	3.7	1.6	60.8
Total	560.0	39.7	28.3	628.0

Conversion from metric

TransCanada reports its operations in the International System of Units (SI). To convert the metric terms shown in this report to the English system of units, the following list of simplified, approximate conversion factors is given:

To Convert	***To***	***Multiply by***
thousands of cubic metres of gas (10^3m^3)	thousands of cubic feet of gas (Mcf)	35.3
cubic metres of oil (m^3)	barrels of oil (bbls)	6.29
kilometres (km)	miles (mi.)	0.62
millimetres (mm)	inches (in.)	0.04
square kilometres (km^2)	acres	247.1
tonnes (t)	tons (short)	1.10
gigajoules (GJ)	millions of British thermal units (MMBtu)	0.95
kilowatts (kW)	Horsepower (HP)	1.34
kilopascals (kPa)	pounds per square inch (psi)	0.15



Top: *New computer control system at Natural Gas Liquids Extraction Plant, Empress, Alberta.*
Bottom: *New addition to the Natural Gas Liquids Extraction Plant, Empress, Alberta.*

Canadian Operations

The majority of the Company's oil and gas interests are located in Canada and are held through its wholly-owned subsidiary, TCPL Resources Ltd. ("Resources"). Commencing with Resources' initial purchase in December 1979 of a 50% undivided interest in the oil and gas properties of Maligne Resources Limited ("Maligne"), a wholly-owned subsidiary of Dow Chemical Canada Inc., Resources has continued to expand its oil and gas interests.

Western Canada

The Company's largest Canadian oil and gas interests are located in the western Canada Sedimentary Basin. As at December 31, 1983, Resources held working interests in 104 000 km^2 and royalty interests in approximately 3 500 km^2 in western Canada. Approximately two-thirds of these interests are in Alberta.

The majority of Resources' interests are held through the MT Partnership, a partnership created in December 1979 and owned equally by Resources and Maligne. In March 1983, Resources assumed the responsibility of managing the partnership's interests from Maligne. These interests are operated for the partnership by Dome.

During 1983, Resources participated in the drilling of 202 gross exploratory wells and 608 gross development wells in western Canada. Of the 202 gross exploratory wells, 75 were completed as oil wells and 59 as gas wells for a success ratio of 66%. Of the 608 gross development wells, 443 were completed as oil wells and 108 as gas wells for a success ratio of 91%. Of particular note was Resources' participation in 68 exploratory wells in five high interest areas in Alberta resulting in 38 oil wells and 15 gas wells. Three of the areas, the Peace River block, the Zama-Shekilie area and the Red Earth-Utikuma area are in northern Alberta. The remaining areas are in south central and southeastern Alberta. Exploratory activity levels increased in the latter half of 1983 as a result of Dome's major farmout agreement with Home Oil Company Limited. Resources' percentage interest in these areas was not altered by the farmout.

Development drilling activity was concentrated in the Valhalla area of northwestern Alberta, the Caroline area of central Alberta and the Grand Forks area in southeastern Alberta, all of which are oil prone areas with potential to generate early cash flow. Extensive activity is proposed for the Valhalla region in 1984. Resources participated in several heavy oil development programs which accounted for approximately 26% of the total development wells drilled by Resources during the year.

Natural gas operations in 1983 concentrated on projects with timely on stream dates. The most significant capital project in which Resources participated was the construction of the West Pembina gas plant. Resources owns a 10.5% interest in the plant which, commencing in mid-1984, will process 1.7 million cubic metres per day of raw natural gas, producing 1 500 cubic metres per day of natural gas liquids and 30 tonnes per day of sulphur.

In 1984, Resources will commence exploration activity in western Canada outside its joint venture activities with Dome. This is a result of Dome's sale of undeveloped lands to Alberta Energy Company Limited in 1983 and subsequent removal of these and adjoining lands from the joint venture area of mutual interest. Similarly, lands in Saskatchewan, on which Dome had proposed limited activity, were also removed from the area of mutual interest late in 1983.

1983 was the first full year of operations since the acquisition of 12½% of the assets of HBOG. Average daily sales were 1 645 cubic metres for conventional and synthetic oil, 281 cubic metres for natural gas liquids and 1.787 million cubic metres for natural gas.

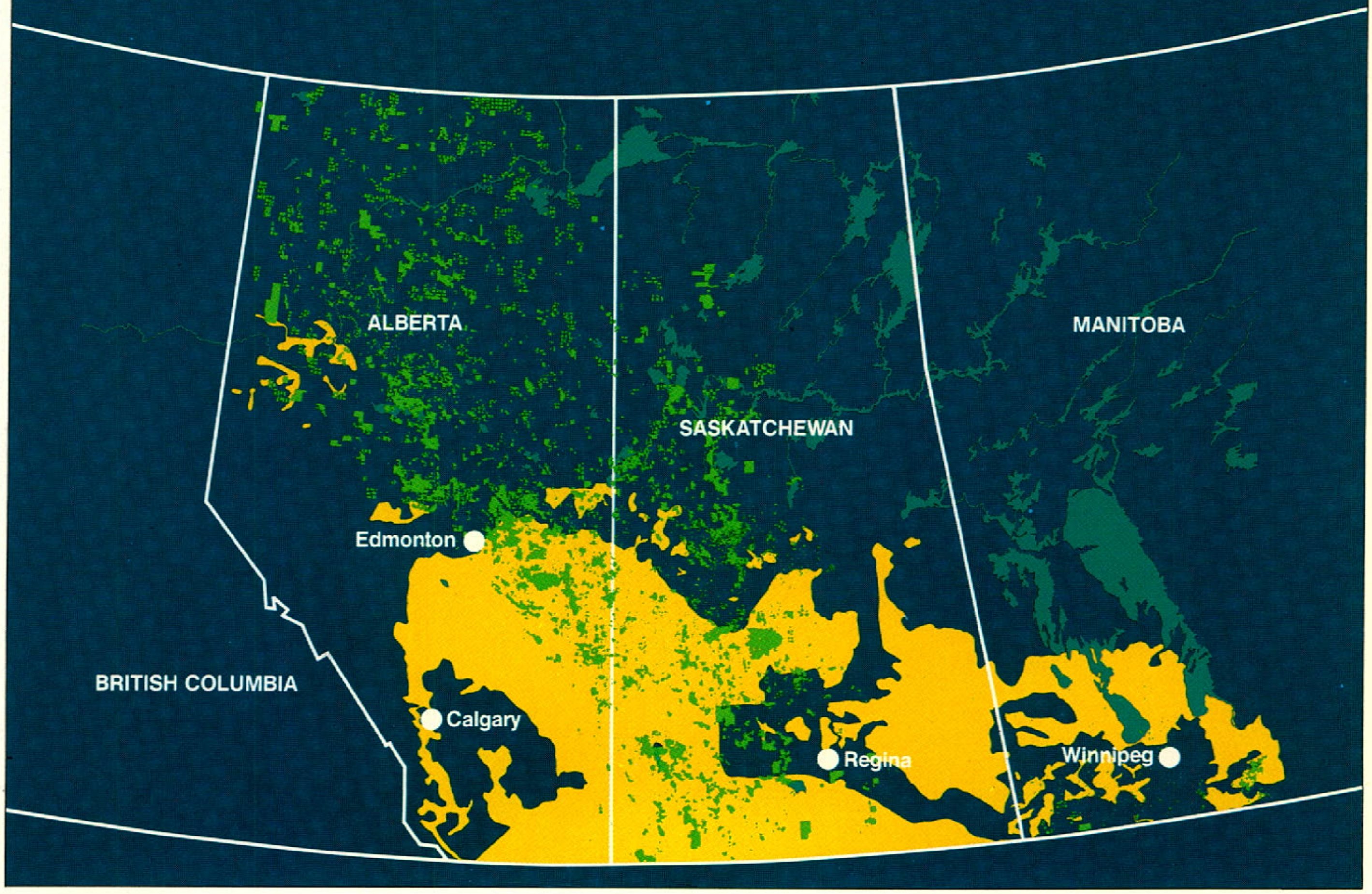
Petroleum and Natural Gas Rights
as at December 31, 1983

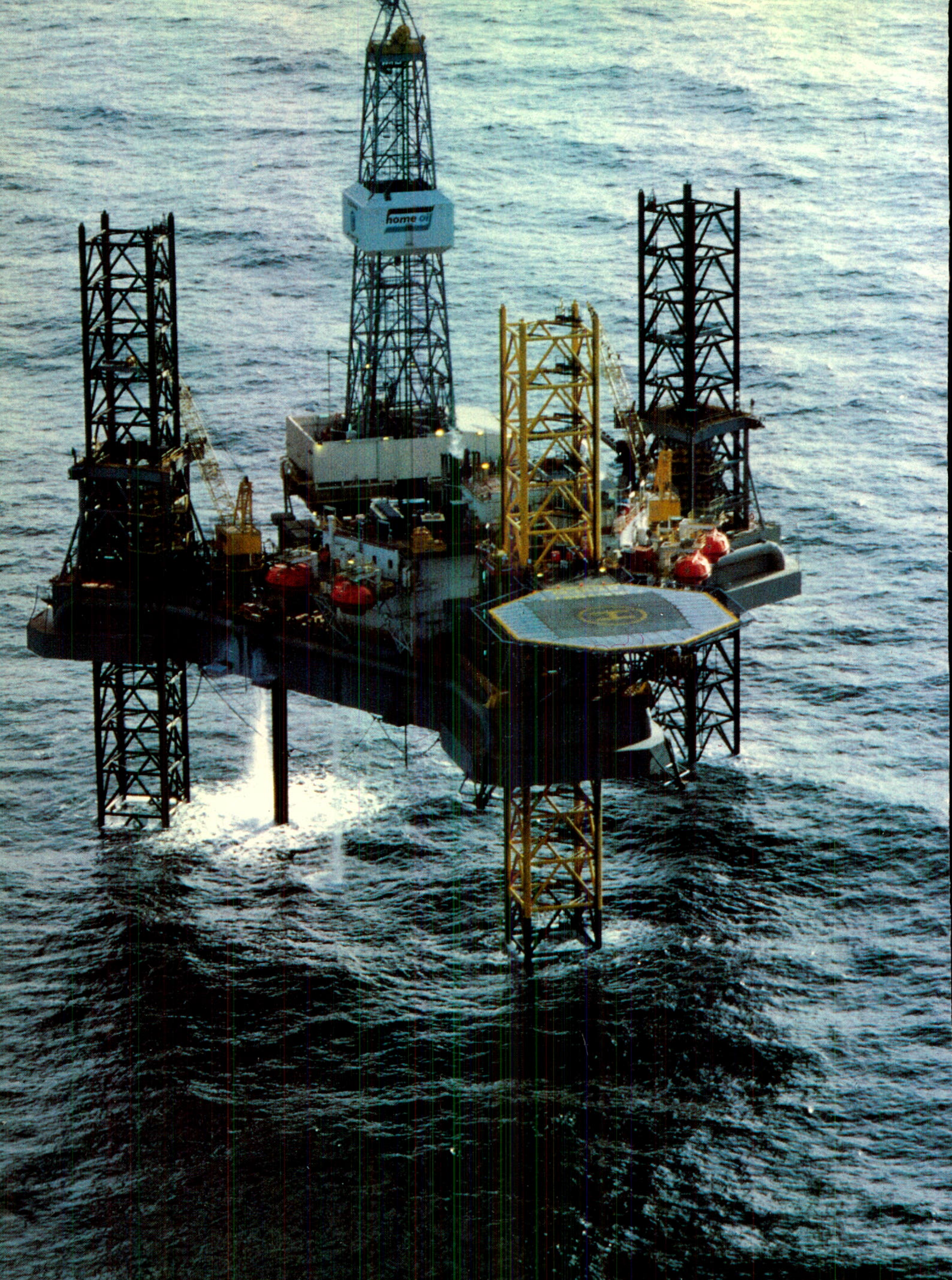
	Working interest			
	S.I. Units (km^2)		Imperial Units (thousands of acres)	
	Gross	Net	Gross	Net
Canada				
Western Canada (1)	103 710	7 480	25,628	1,849
Frontier (2)	72 640	2 920	17,950	721
Total Canada	176 350	10 400	43,578	2,570
U.S.A.	11 110	1 080	2,746	268
International				
Indonesia	52 980	1 780	13,092	439
Australia (3)	20 490	1 180	5,062	290
Italy	1 160	110	286	26
North Sea (4)	1 280	50	317	12
Egypt	2 700	50	667	14
Total International	78 610	3 170	19,424	781
Grand Total	266 070	14 650	65,748	3,619

(1) Includes Alberta, British Columbia, Saskatchewan, Manitoba and Ontario. In addition royalty interests are held in 3 500 km^2 (865 m acres).
(2) Includes Arctic Islands, Beaufort Sea, East Coast Offshore, and the Northwest Territories.
(3) The gross and net figures for Australia do not include the Block ATP 257 in which Resources will earn an interest after fulfilling seismic and drilling obligations during 1984.
(4) Includes holdings in the United Kingdom and Dutch sectors of the North Sea.

TCPL Resources Ltd.

Working interest acreage
General area of mineral title lands




home oil

Frontier

All of Resources' frontier land holdings are held under proposed Exploration Agreements with the Canada Oil and Gas Lands Administration department. Resources has varied interests, mostly minor, in a total of 18 offshore Exploration Agreements of which 9 are located in the Arctic Islands, 2 in the Beaufort Sea, and the remaining offshore Eastern Canada. These Agreements are for terms of three to five years and each require minimum specified work obligations and include acreage relinquishment provisions. Of particular note is the Home et al Louisbourg J-47 well, which was in the process of drilling at year end approximately 415 km east of Halifax, Nova Scotia. Resources has a 7.308% working interest in the well, which is the first of two obligatory wells to be drilled on the 2 400 km^2 block.

Oil Sands

The Company's share of synthetic crude oil sales from its 0.625% interest in the Syncrude Oil Sands Project averaged 111 cubic metres per day in 1983. A debottlenecking and expansion program for Syncrude's plant is planned over the next four years and will increase gross production levels by approximately 3 180 cubic metres per day.

National Energy Program

Resources qualified for maximum incentive grants payable under the government of Canada's National Energy Program in 1983. The payments, in essence, rebate a specified percentage of approved oil and gas exploration and development costs.

Cancarb

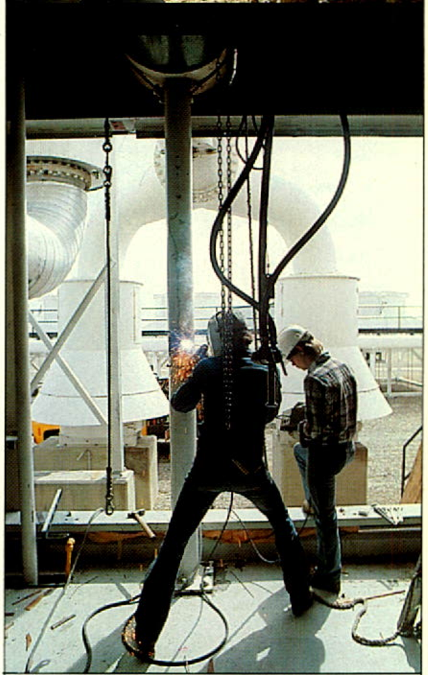
Acquired by TransCanada in October 1981, Cancarb operates one of the most modern thermal carbon black facilities in the world at Medicine Hat, Alberta and markets its product, Thermax, throughout the world. Thermax is derived from natural gas and is the purest of carbon black, containing the lowest levels of ash, metallics and sulphur. It is an important ingredient in many manufacturing processes.

Under an aggressive marketing program, Cancarb is expanding sales in the United States, Europe, and the Pacific Rim countries. With steady growth forecast over the next five years a 50% expansion of the Cancarb plant is scheduled to be completed in late 1986 or early 1987, at a cost of about $15 million.

Cancarb also purchases and resells natural gas for use in enhanced oil recovery operations in Alberta.

Empress Extraction Plant

During 1983, Resources acquired the right to a 50% participation in a new extraction plant at Empress, Alberta. The investment is on a cost of service basis with the total cost of the plant estimated to be $155 million including interest during construction. The testing of the new plant began on November 9, 1983 followed by an official start-up utilizing one of two trains on November 16, 1983. Performance testing of both trains is expected to take place during April of 1984, at which time the plant will have capacity to process an inlet volume of approximately 56 million cubic metres per day and have the capability to extract 5 500 cubic metres per day of ethane and 2 800 cubic metres per day of liquid petroleum gases.



Left: *Drilling platform, Home et al Louisbourg J-47 well.*

Top: *Tightening valve packing beside a low pressure gas separator.*

Middle: *Radiography of pipeline weld.*

Bottom: *Fabricating a pipe support. Station 13, Caron, Saskatchewan.*

United States Operations

Prior to 1983, Resources U.S.A. explored for oil and gas in the United States solely through its passive participation in a joint venture with Dome Petroleum Corp. in a joint venture (the Dome Joint Venture). Continued budget restraints of Dome necessitated Resources U.S.A. assuming an active management role in exploration. Accordingly, a professional staff was recruited and put into place during the year. Resources U.S.A. was able to take advantage of a number of attractive investment opportunities in 1983 and thus expended approximately (U.S.) $8.1 million on exploration, development, and land acquisitions independent of the Dome Joint Venture. Approximately (U.S.) $2.9 million was expended under the Dome Joint Venture. Effective November 1, 1983, the Dome Joint Venture was terminated.

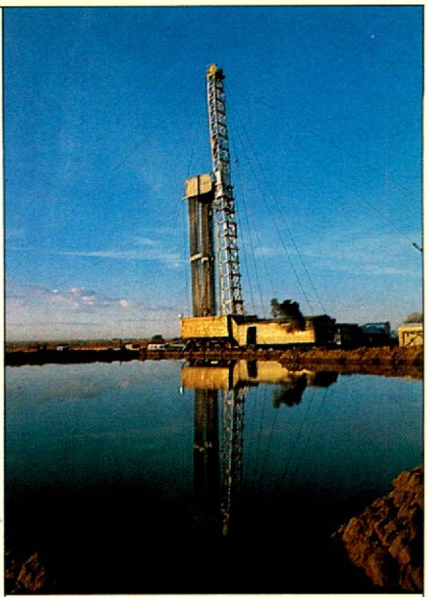
During the year, Resources U.S.A. participated in the drilling of 14 exploratory wells and 19 development wells. Of the 33 wells drilled, 7 were drilled under the Dome Joint Venture of which 3 were completed as oil wells. Of the 26 wells drilled outside the Dome Joint Venture, 11 were completed as oil wells and 3 were completed as gas wells. In addition, 19 wells were drilled at no cost to Resources U.S.A. as a result of farmout agreements with other companies. Of these 19 farmout wells, 4 were completed as oil wells and 7 were completed as gas wells.

With successful independent exploration activity, production rates climbed in 1983, particularly in the latter half of the year. Crude oil and natural gas liquids sales averaged 46 cubic metres per day in 1983, up 44% from 1982 levels. Natural gas sales averaged 40 945 cubic metres per day in 1983, up 15% from 1982 levels. Approximately 60% of the gas production and substantially all of the natural gas liquids production is attributable to Resources U.S.A.'s interest in Fields Field in Beauregard Parish, Louisiana. Oil production is not concentrated in any particular region.

Operations outside the Dome Joint Venture resulted in new reserve additions of over 175 000 net equivalent cubic metres of oil in 1983. In comparison, Resources U.S.A.'s reserves at December 31, 1982 were approximately 313 000 net equivalent cubic metres of oil. In the latter half of 1983 TCPL Resources Ltd. transferred its 3.125% interest in natural gas reserves, located in the Gulf of Mexico, to Resources U.S.A.

Resources U.S.A.'s net land inventory, located in 25 states, decreased from 12 080 km^2 at December 31, 1982 to 11 110 km^2 at December 31, 1983. The 1983 year end total included 1 080 km^2 acquired through acquisitions outside the Dome Joint Venture, the majority of which are in the Williston Basin, the Uinta Basin and the Powder River Basin. In the latter half of 1983, Resources U.S.A. entered into a joint exploration program with Spartan Petroleum Corporation in the onshore Gulf Coast area of Texas and Louisiana that is expected to result in additional land purchases and drilling activity during 1984.

Resources U.S.A. will continue to expand its exploration and development activities in the United States in 1984. Areas of principal activity will be the Rocky Mountain states, Oklahoma and the onshore Gulf Coast area of Texas and Louisiana.



Left: *View from the travelling block on a Colorado well in which Resources U.S.A. participated.*

Top: *Drilling rig on Government Doty #1, Weld County, Colorado.*

Above: Close up of drilling operations, Government Doty #1, Weld County, Colorado.

Bottom: Pulling pipe at a well in the Garrington area, Alberta.

Foreign Operations

At year end, the Company held interests in six countries outside North America. During 1983, exploration activities were carried out in Indonesia, Australia, Italy, and the North Sea.

Indonesia

In the Southeast Sumatra production sharing contract area, comprising 14 870 km^2, where the Company holds a 1.226% interest, 108 wells were drilled during 1983, resulting in 59 oil wells and 49 dry holes. The gross daily crude oil production rate for the contract area continued at an average rate of 15 900 cubic metres per day. The anticipated production decline in 1983 was offset by the Karmila A field which came onstream during 1983 at a gross production rate of 4 290 cubic metres per day.

In the Malacca Strait production sharing contract area, comprising 11 840 km^2, where the Company holds a 7.08% interest, development drilling in the Lalang oil field was initiated and was essentially complete by year end. Production startup date for the Lalang field is scheduled for mid-1984 at an average rate for the balance of the year of approximately 5 565 cubic metres of oil per day.

In the Madura Strait production sharing contract area, comprising 13 970 km^2, where the Company holds a 4.167% interest, a 3 500 km seismic program was completed during 1983. Two drillable structures have been identified and the drilling of one exploratory well is planned for 1984.

In 1983, the Company, in conjunction with other interest owners, farmed out its interest in the Natuna B production sharing contract area. The farmee will spend (U.S.) $6 million to drill one well and earn a 50% working interest in the contract area. The Company's interest in the contract area, encompassing 12 300 km^2, will be reduced from 2.84% to 1.42% after the farmout.

Australia

In Australia, the Company participated in acquiring two additional onshore blocks in 1983, which brings the Company's present total to five oil prone blocks totalling 20 490 km^2, with interests ranging from 3.75% to 15%. During the year, seismic programs were conducted on two of the onshore blocks in preparation for four exploratory wells planned in 1984.

Italy

The Company has varied interests in three exploration permits located offshore in the Sicily Channel.

During 1983, seismic surveys were conducted on the CR100 and the CR108 blocks. Of particular interest is the program undertaken on Block CR100, which is in proximity to the recent major Vega oil discovery. One exploratory well will be drilled in this block during 1984. Under a farmout agreement reached in early 1984 the Company is also participating in a second well in the area which is currently being drilled.

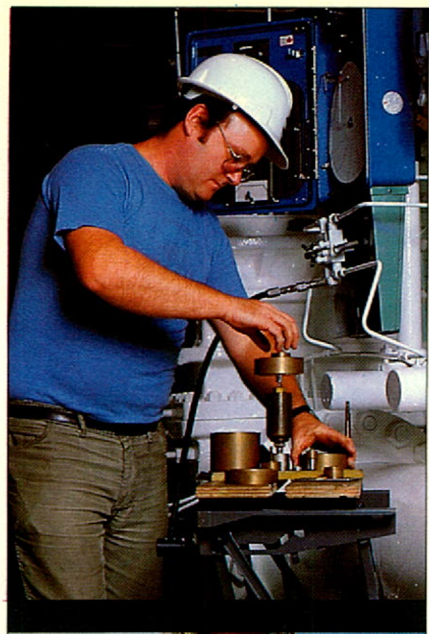
The Company is currently endeavouring to expand its holdings in Italy by participating in a Study Group. During 1983, three applications were submitted by the Study Group to the Italian Government to obtain exploration permits in the Adriatic Sea and the Sicily Channel.

Reserves

As at December 31	**1983**	1982
Oil and Natural Gas Liquids (thousands of cubic metres)		
Canada — conventional and natural gas liquids	**10 440**	11 848
— synthetic	**961**	1 002
United States	**196**	109
Other Foreign	**934**	859
	12 531	13 818
Natural Gas (millions of cubic metres)		
Canada	**25 134**	25 579
United States	**161**	141
Other Foreign	**—**	—
	25 295	25 720

Reserve figures include working and royalty interests after deduction of gross overriding and freehold royalties but before deduction of Crown royalties and include proven reserves and a risked portion of probable reserves as defined by the Alberta Energy Resources Conservation Board. Remaining established oil reserves in Canada as at December 31, 1983 have been reduced to reflect the correction of an error in calculated 1982 reserves and a reclassification of heavy oil reserves by Dome Petroleum.

Oil and Gas Interests



Left: Construction of an offshore production platform in Indonesia.
Top: Technician inspecting regulating station, St. Lazare, Quebec.
Bottom: X-ray operator applying lead numbers to an X-ray film.

North Sea

The Company has minor interests in four offshore blocks located in the Dutch sector of the North Sea. One oil field and two gas fields were discovered in three of the blocks.

In the United Kingdom sector of the North sea, the Company holds a 13.75% interest in the 22/19 Block, comprising 220 km^2. Two excellent structures have been mapped within the Block and one exploratory well commenced drilling early in 1984.

Egypt

During 1983, the Company participated in the Abu Roda well, located on the 2 700 km^2 Bardawil Block in the Sinai Peninsula in which the Company holds a 2.08% interest. The well was abandoned after encountering gas shows. A seismic program will be carried out in the Block during 1984.

Mining Operations

Cyprus Anvil

Cyprus Anvil Mining Corporation (''Cyprus Anvil''), in which the Company holds a 12.5% interest, owns an open pit lead-zinc-silver mine and ore concentrator at Faro, in the Yukon, as well as similar ore bodies in the immediate area of the mine and in northern British Columbia. Mining operations were suspended in the spring of 1982. In April 1983, an agreement was entered into between the government of Canada and Cyprus Anvil which provides an Action Plan that involves the removal of overburden from the ore body in the Faro pit in preparation for the resumption of production from the mine, once market conditions permit. Improvements in zinc and lead prices have made the future of Cyprus Anvil much brighter than a year ago. With continuing improvement in zinc prices, resumption of ore production could commence in late 1984 or early 1985 if satisfactory transportation arrangements can be made.

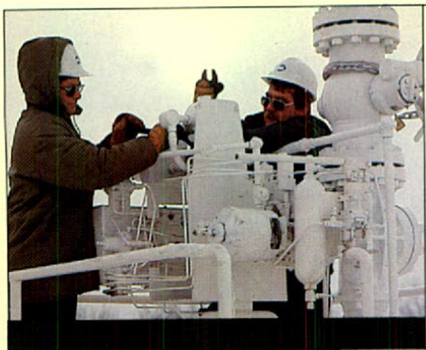
The ultimate realization of the Company's investment in Cyprus Anvil is dependent on resumption of profitable operations which is itself dependent upon Cyprus Anvil reducing certain operating expenses, obtaining satisfactory capital financing, and upon improved mineral market conditions, and general economic conditions.

Other Mining Interests

The Company indirectly owns a 4.1667% interest in Les Mines Selbaie, a copper-silver-gold mine in northwestern Quebec. The mine commenced production in the fall of 1981 and in 1983 processed 535 300 dry tonnes of ore. Despite low metal prices, an operating profit was realized in 1983.

At December 31, 1983, recoverable ore reserves at Les Mines Selbaie amounted to over 3 million tonnes, grading 3.72% copper, 36.1 grams of silver per tonne and 1.13 grams of gold per tonne.

In addition, the Company held mineral interests in 2 230 km^2 (net 163 km^2) throughout Canada as at December 31, 1983.



Right: West Pembina Gas Plant, under construction, near Drayton Valley, Alberta.

Top: Checking upstream tie over valve. Station 41, Ile des Chênes.

Bottom: Moving solvent from drum depot.

Finance Division

Finance

The year 1983 was marked by stable interest rates at levels lower than those experienced for a number of years. As forecast at the end of 1982, the capital requirements of TransCanada were minimal in 1983. The table below details the financing completed by the Company in 1983.

Issue	Maturity	Interest Rate
100,000,000 Swiss Franc Notes	1993	5¾%
$100,000,000 Debentures	1993	11.70%

The 11.70% Debenture issue was the first Canadian public debt transaction that the Company has completed in a number of years. This was as a result of the market for corporate debt issuers in Canada reopening in 1983. The interest rate obtained by the Company was the lowest for any corporate issuer in Canada in 1983 for an issue with a maturity of 10 years or greater.

The Swiss franc note issue was undertaken in 1983 to support TransCanada's oil and gas activities.

In addition to the transactions listed above, TransCanada completed an interest rate swap during the year. The interest rate on approximately $48 million of the floating rate debt of the Company's 50%-owned oil and gas partnership was fixed for a period of five years. This debt is secured by the partnership's interest in certain oil and gas properties and is non-recourse to the Company.

The Company completed the Topgas Two Program in December whereby the Company's 1983 take or pay payments to producers were funded by a syndicate of banks. Approximately $310 million was advanced by the syndicate to producers representing over 90% of the Company's gas supply. The Topgas Two Program was, in most respects, identical to the Topgas Program completed in 1982. A major difference is that the future take or pay level has been reduced from 60% to a level derived from a formula that takes into account the level of take by the Company for the two preceding contract years subject to a minimum of 50%.

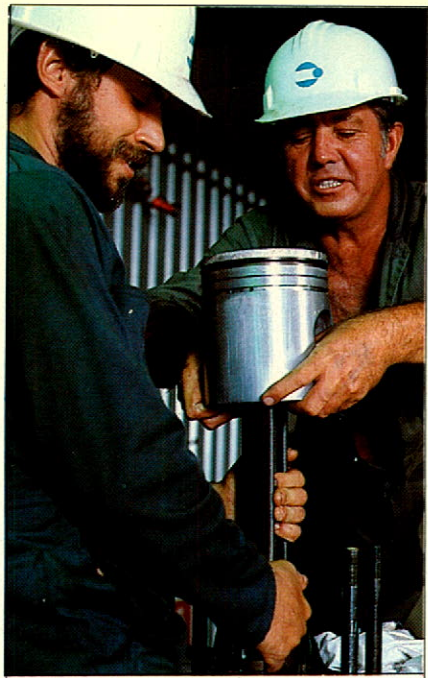
At the end of March 1984, the Company had outstanding take or pay payments of approximately $50 million to producers who did not participate in the Topgas Two Program. The Company expects that the majority of these producers will join the program in 1984 and that the payments made by the Company will be refunded.

Banking

Lower short-term interest rates had a significant impact on the Company's cost of short-term funds in 1983. The Company's commercial paper program was also expanded from $50 million to $150 million during the year. The result of the lower rates and the expanded commercial paper program was that the Company's average cost of short-term funds was 10.63% in 1983 on average outstandings of $181.9 million.

In the short-term investment area, the Company earned an average of 9.09% on an average Canadian investment of $7.7 million and 9.34% on average United States investments of (U.S.) $74.2 million.

In early 1984, the Company's commercial paper program was further increased from $150 million to $250 million. This should have a positive impact on the Company's cost of short-term borrowings in 1984.



Left: *Construction at the Natural Gas Liquids Extraction Plant, Empress, Alberta.*

Above: *Installing pistons in a reciprocating engine.*
Station 802, Candiac, Quebec.

International Subsidiaries and Affiliates

The Netherlands
TCPL Nederland B.V.
TransCan Nederland B.V.
TRP Nederland B.V.
TCPL Holdings B.V.

The Netherlands Antilles
TransCan Finance N.V.
T.R.P. Finance N.V.
TCPL Finance N.V.

Switzerland
Cancarb AG
TCR Madur AG
TCR Malac AG
TCR Natun AG
TCR Sumat AG
TCPL Investments AG
TCR Resources AG

The Channel Islands
TransCan Investments Limited

Dividend Reinvestment and Stock Dividend Plans

The Company's Dividend Reinvestment and Share Purchase Plan and Stock Dividend and Share Purchase Plan were instituted during 1983. The plans raised a total of $9 million for the Company, a figure significantly above that which had been anticipated. A total of 2,194 shareholders are presently taking advantage of the two plans. The Company believes that the plans provide a benefit to those shareholders participating while raising common equity for the Company at a cost which is competitive with public issues. The table below details the results of the first year's operation of the plan, reflecting the two-for-one share split.

	Dividend Reinvestment Plan			Stock Dividend
	Common	Preferred	Total	Plan
Shares enrolled in plan at December 31, 1983	47,722,560	701,112	—	767,949
Proceeds				
—from dividends	$7.0 million	$.7 million	$7.7 million	$.6 million
— from optional cash payments	—	—	.5 million*	.2 million
			$8.2 million	$.8 million
Common shares issued				
— for dividends	540,432	50,542	590,974	49,122
— for optional cash payments	—	—	35,902*	11,900
			626,876	61,022

*These figures cannot be separated between common and preferred.

During 1983, shares issued as dividends under the Plans were issued at the average price of $12.98 on a post-split basis and optional cash payments purchased shares at an average price of $13.62.

International Operations

The European operation continued to expand and consolidated its activities. During 1983, TCPL Nederland B.V. borrowed term loans for the equivalent of (Cdn.) $77.3 million from three international banks.

Issue	Maturity	Interest Rate
50,000,000 Swiss francs	1984-1988	6⅞%
100,000,000 Dutch guilders	1984-1988	7⅞%
20,000,000 Dutch guilders	1984-1988	7⅞%

These funds will be used for expansion and general corporate purposes by TransCanada's affiliates in the United States. It is anticipated that these international activities will continue to grow and add more financial flexibility to the Company's foreign operations.

Corporate Division

Left: Hourly plant equipment check. Station 58, Ignace, Ontario.

Employees

A major strength of TransCanada PipeLines continues to be its employees. Their dedication, hard work and loyalty over the years has contributed significantly to the Company's overall growth and prosperity.

At the end of 1983, almost 2,000 men and women worked for TransCanada in seven Canadian provinces, the United States, and overseas. They were joined during the year by approximately 400 university, college and high school students, who were hired as part of the Company's annual summer student program.

In 1983, many employees made special efforts to meet the problems of productivity and changing technology by sharpening their skills and enhancing their knowledge through various Company sponsored programs. During the year, almost 300 employees attended evening and night courses at universities and colleges across the system and qualified to receive reimbursement under the Company's Education Refund Plan. A total of 167 participated in supervisory and management programs, 216 attended special administrative courses and many more took part in technical seminars and workshops.

In addition to volunteering their time and energy to community service, employees of TransCanada contributed generously in 1983 to the United Way campaign — helping to support the towns and cities in which they live and work.

All employees are eligible to become shareholders of the Company through the Stock Savings Plan. The Plan had purchased a total of 1,166,584 common shares at the close of 1983, on a post split basis.

Shareholders

During 1983, Dome Petroleum Limited, Dome Canada Limited and Dome Investments Limited, a wholly-owned subsidiary of Dome Petroleum Limited, disposed of the 46.02% of the common shares of the Company held by them. Most of the shares were sold by way of secondary offerings in March and August, 1983 and the balance held by Dome Canada (11.8%) were sold privately by Dome Canada to BCE in December 1983 at a price of $15.75 per share on a post share split basis. BCE then made an identical offer to all other shareholders of the Company and shareholders representing a further 30.5% of the Company's common shares accepted the BCE offer, making BCE the Company's largest shareholder, with 42.3% of the outstanding common shares at December 31, 1983.

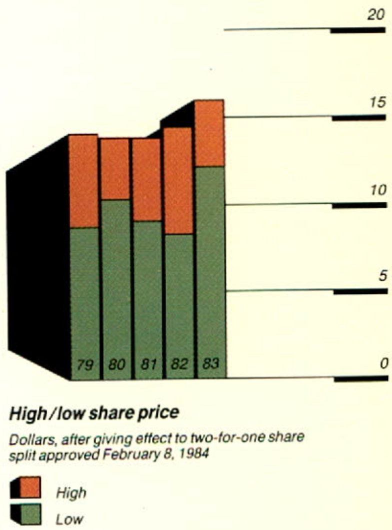
At a Special Meeting of the common shareholders held in Calgary on February 8, 1984, the subdivision of outstanding shares on a two-for-one basis was approved. During the year the number of common shareholders fluctuated as a result of the sale of shares by Dome Canada, Dome Investments and Dome Petroleum and the subsequent offer by BCE. At the end of 1983, the number of shareholders was slightly above the number of shareholders at the end of 1982. During 1983, the market price per common share restated to reflect the share split which took place in 1984 varied from a low of $12.06 to a high of $15.81. TransCanada's common shares are listed on the Vancouver, Alberta, Winnipeg, Toronto and Montreal Stock Exchanges.

The profile of common shareholders by category of shareholdings was much the same at the end of 1983 as it was at the end of 1982.

Profile of common shareholders by category of shareholdings:

	December 31, 1983		December 31, 1982	
Category	Shareholders	Shares*	Shareholders	Shares*
1 - 99	8,095	663,624	8,596	723,774
100 - 999	12,290	6,743,854	11,863	6,594,294
1,000 - 99,999	2,001	18,102,892	1,885	22,089,254
Over 99,999	29	65,409,430	34	60,172,380
Total	22,415	90,919,800	22,378	89,579,702

*After giving effect to two-for-one share split approved February 8, 1984.



High/low share price

Dollars, after giving effect to two-for-one share split approved February 8, 1984

Geographic Share Distribution

(as of December 31, 1983)

	Number of Shareholders	Number of Shares
Newfoundland	42	162,976
Nova Scotia	581	785,012
Prince Edward Island	63	58,150
New Brunswick	302	275,934
Quebec	2,754	48,799,058
Ontario	9,442	31,813,720
Manitoba	955	2,633,936
Saskatchewan	601	425,946
Alberta	2,343	2,207,882
British Columbia	3,376	2,507,750
Northwest Territories	2	1,100
Yukon Territory	4	162
Total Canadian	20,465	89,671,626
U.S.A.	1,793	1,073,806
Other Countries	157	174,368
Total Non-resident	1,950	1,248,174
Overall Total	22,415	90,919,800

Corporate Division

Organization

A further number of changes have been made in senior management responsibilities during 1983 since the publication of the 1982 Annual Report of the Company.

TransCanada Vice-Chairman and Chief Operating Officer George W. Woods has stepped down as Chief Operating Officer of the Company. Mr. Woods continues as Vice-Chairman, with responsibility for the Company's activitities in Great Lakes Gas Transmission Company, the Alaska Natural Gas Transportation System, Northern Border and Polar Gas. Mr. Woods also has major responsibilities in the area of government relations.

In the *Alberta Division,* Mr. C. R. Frew has been appointed Vice-President, Operations and Mr. B. G. Luft has been appointed Vice-President, Gas Supply.

In the *Pipeline Division,* Mr. R. D. Walker has been appointed Senior Vice-President and Chief Operating Officer. Mr. G. M. Hugh has been appointed Senior Vice-President, Marketing and Administration. Mr. R. J. Reid, Vice-President, Engineering and Operations, will assume responsibility for all Engineering and Operations activities.

In the *Corporate Division,* Mr. J. K. Archambault has been appointed Senior Vice-President, Corporate. Mr. J. W. S. McOuat, Q.C., has been appointed Vice-President, Law.

In the *Finance Division,* Mr. H. N. Nichols has been appointed Senior Vice-President and Chief Financial Officer. Mr. M. T. G. Graye has been appointed Vice-President, Finance and Treasurer. Mr. B. F. Hill has been appointed Vice-President, Business Development.

In *International Operations,* Mr. L. H. Pilon has been appointed Executive Vice-President TransCan Holdings, Managing Director of TCPL Nederland BV, and Managing Director, TCPL Investments AG.

Top: Corrosion detection crew, Red Jacket, Saskatchewan.

Middle: TransCanada employees studying electronic maintenance at Seneca College, Toronto, Ontario.

Bottom: Leak detection crew along the line.

1983 Financial Review

Index

Report of Management

The accompanying consolidated financial statements and all information in the Annual Report are the responsibility of management and have been approved by the Board of Directors of the Company. The consolidated financial statements of the Company have been prepared by management in accordance with accounting principles generally accepted in Canada which, except as described in Note 10, have been consistently applied. These principles also conform in all material respects with International Accounting Standards on an historical cost basis. Other financial information in the Annual Report is consistent, where appropriate, with the financial statements.

The Board of Directors has appointed an Audit Committee to review with management and the independent auditors the annual financial statements of the Company prior to submission to the Board of Directors for final approval. The Audit Committee also meets periodically during the year with management and the internal and external auditors either individually or as a group. Internal and external auditors have free access to the Audit Committee without obtaining prior management approval.

The independent auditors, Peat, Marwick, Mitchell & Co., have been appointed by the shareholders to express an opinion as to whether the consolidated financial statements on pages 51 to 65 present fairly the Company's financial position, operating results and source of funds for capital expenditures in conformity with generally accepted accounting principles.

Their report on page 65 outlines the scope of their examination and their opinion on the financial statements.

Financial Commentary

1983 Financial Review

Earnings and related cash flow from the Company's regulated Canadian pipeline operations are primarily determined by the rate of return on rate base approved by the National Energy Board, including a return on common equity, and the actual performance of the Company in the period during which rates are effective. The Company's tolls for gas sales and transportation are designed to provide the Company with the opportunity of earning its approved return on rate base, including a fair and reasonable return on common equity. Tolls are based on a number of factors, including projected estimates of the level of the Company's rate base, operating costs and certain financing costs. If, in the period during which rates are effective, variations occur between actual and estimated costs, the Company may earn more or less than its approved return on rate base.

Results of Operations

In 1983 net income applicable to common shares was $191.8 million, an increase of $30.7 million or 19.1% from $161.1 million in 1982. Earnings per common share, after giving effect to the two-for-one share split, approved by the shareholders on February 8, 1984, were $2.13 in 1983 and $1.81 in 1982.

In 1983, total sales volumes for the utility transmission system decreased by 9.9% compared to 1982, as a result of a 4.5% decline in domestic volumes and a 36.8% decline in export volumes to the United States. Despite the decline in domestic sales volumes, domestic sales revenue increased by $408.2 million compared to 1982, principally due to several rate increases.

Export sales revenue decreased by $412.7 million in 1983 compared to 1982 due to volume decreases referred to above. These decreased volumes resulted from depressed economic conditions in certain parts of the United States, the price differential between the regulated export price of Canadian natural gas and other energy sources and the availability in the United States of alternate energy sources.

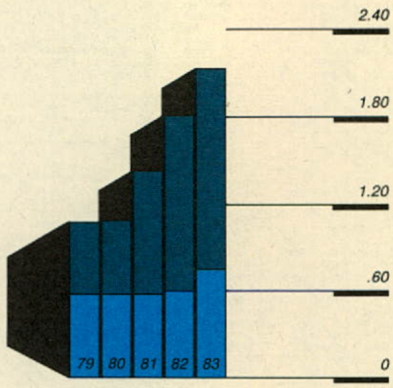
Cost of gas sold increased by $61.5 million over 1982. Prior to October 1982, take or pay financing costs were recovered in the Company's Alberta cost of service with the recovery credited as a reduction of Cost of gas sold. The offsetting expense was included in Financial charges, Income taxes and the Provision for preferred dividends. From October 1982 onward, substantially all of the Company's take or pay payments have been financed by banking syndicates under arrangements referred to as the Topgas Programs (See Note 1 on page 58) and, since that date, are no longer reflected in the Company's accounts. As a result, take or pay financing costs deducted from Cost of gas sold by the Company in 1983 were reduced to $2.9 million from $146.5 million in 1982.

The decrease of $34.8 million in Transmission, operating and general expenses is primarily the result of sales and transportation volume reductions.

Income from pipeline equity investments increased to $84.6 million in 1983 from $52.9 million in 1982. This increase is mainly attributable to the impact of a full year of operations in the Northern Border segment of the Alaska Natural Gas Transportation System.

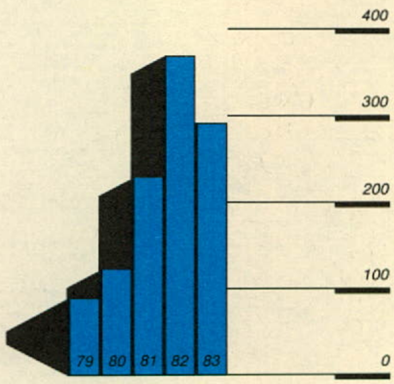
The Company's income from its investment in natural resources, after reflecting the reclassification of financing costs associated with the oil and gas properties as described in Note 3 on page 62, increased to $63.8 million in 1983 from $59.4 million in 1982. Despite a slight decrease in production and sales volumes in Canada in 1983 compared to 1982, revenues increased by 13.0% due to oil and gas price increases during the period. However, because of increasing operating expenses, income from natural resource operations before financing costs remained relatively unchanged from 1982.

After reflecting the reclassification of financing costs associated with oil and gas properties as described in Note 3 on page 62, Financial charges decreased by $64.4 million to $333.2 million in 1983 from $397.6 million in 1982. This decrease reflects the impact of the financing of the Company's take or pay payments by banking syndicates



Net income per common share

Dollars, after giving effect to two-for-one share split approved February 8, 1984



Financial charges (net)

Millions of dollars

under the Topgas Programs. Interest costs for financing these payments included in Financial charges are $2.9 million and $96.0 million in 1983 and 1982 respectively. This decrease was partially offset by a $27.3 million reduction in interest capitalized in 1983 compared to 1982. The impact on Financial charges of five new issues of long-term debt in 1983 was minimized due to a combination of reduced interest costs on the Company's floating rate debt and low rate foreign currency issues.

Liquidity and Capital Resources

Funds generated by operations and equity investments increased to $394.3 million in 1983 from $326.3 million in 1982. The Company was required, by a decision of the National Energy Board, to adopt the taxes payable method of recording income taxes applicable to its Canadian utility operations effective August 1, 1982. If this change had not been required, cash flows would have been greater by $43.4 million in 1983 and $27.6 million in 1982. Further, in response to the federal government's restraint program, the Company deferred an increase in the rate of return, effective August 1, 1983, on its investment in the extension of the pipeline system from North Bay to Morrisburg, Ontario, resulting in a reduction of cash flow of approximately $19 million. Contributing to the improvement in 1983 cash flow over 1982 was the level of dividends received from the Company's pipeline investments, which increased to $69.3 million from $29.3 million.

Capital expenditures by the Company during 1983 were $303.3 million, a decrease of $529.7 million from the level in 1982 reflecting among other things significantly lower capital expenditures on the pipeline system. Capital expenditures made by the natural resource joint ventures reached a level of $94.3 million in 1983 from $628.0 million in 1982. The 1982 amount reflects the HBOG acquisition described in Note 3 on page 62.

Inflation and Its Impact

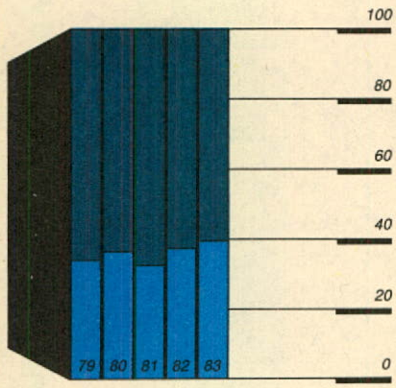
A discussion of whether the primary financial statements of the Company, measured in historical dollars, accurately report the impact of inflation, must begin with an understanding of the economics of the regulatory environment; an environment which contributes over 90% of the Company's net income and represents approximately 80% of its assets. Rate regulation is primarily based upon the recovery of historical costs. The objective of the rate making process is to determine the total amount of revenues the Company must generate from its operations to permit the recovery of its operating costs and costs of capital, including a return on rate base. To achieve this, the Company's cost of service is determined on a prospective basis, whereby anticipated costs of operations and capital requirements are adjusted to reflect changing prices.

Accordingly, the Company considers that its primary financial statements accurately depict the economics of its regulated operations in Canada and the United States, and the impact of inflation. Further, to include statements prepared on any other basis may be misleading.

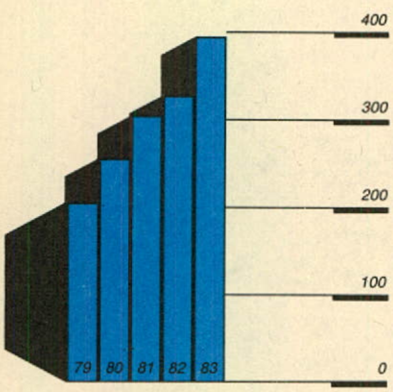
The Company's non-regulated investments are primarily represented by oil and gas operations in Canada, where prices are established by government policies. Although prices in Canada have been rising over the past several years, they are influenced by the international price of oil. At the same time, operating and capital costs have been increasing rapidly over the same period.

Inflation adjustments primarily arise where inventories and property, plant and equipment are recorded in the primary statements at costs significantly lower than today's market values. These inflation adjustments would not have a significant impact on income or return on the Company's investment in oil and gas properties since the inventory component is immaterial and all oil and gas properties have been acquired in the past four years.

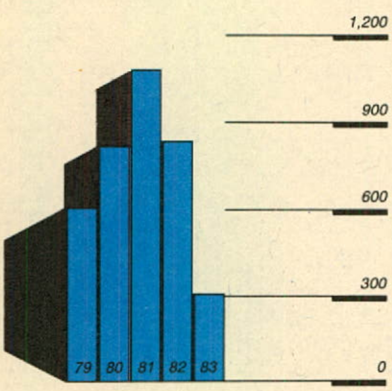
Additional information with respect to the costs of acquiring, exploring and developing the Company's oil and gas reserves, together with a schedule of reserves, is included on pages 28 and 37 of this report.



Debt/equity ratio
Percent
Debt
Equity



Funds generated by operations and equity investments
Millions of dollars



Capital expenditures
Millions of dollars

Consolidated Income

Year ended December 31, 1983

(stated in millions of dollars with comparative figures for 1982)	1983	1982
Revenues		
Gas sales — domestic	2,790.9	2,382.7
— export	568.4	981.1
Gas transportation and other	111.4	103.1
	3,470.7	3,466.9
Costs and Expenses		
Cost of gas sold	2,486.9	2,425.4
Transmission, operating and general	517.2	552.0
	3,004.1	2,977.4
Income from Investments		
Pipelines (Note 2)	84.6	52.9
Natural resources (Note 3)	21.7	30.1
	106.3	83.0
Other Income		
Allowance for funds used during construction	8.5	45.2
Other (net)	23.3	16.0
	31.8	61.2
Income Before the Undernoted Items	604.7	633.7
Financial Charges		
Interest on long-term debt (net)	284.9	364.8
Other interest and finance costs	6.2	3.5
	291.1	368.3
Income Taxes		
Current	3.2	12.8
Deferred	82.3	53.7
	85.5	66.5
Net Income for the Year	228.1	198.9
Less provision for dividends on preferred shares	36.3	37.8
Net Income Applicable to Common Shares	191.8	161.1
Net Income per Common Share (Note 11)	$2.13	$1.81

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

Consolidated Financial Position

December 31, 1983

(stated in millions of dollars with comparative figures at December 31, 1982)	1983	1982
Assets		
Current Assets		
Cash and temporary cash investments	223.0	99.9
Accounts receivable	544.9	592.2
Inventories — at cost	123.4	119.1
Prepayments and deposits	6.2	4.8
	897.5	816.0
Payments on Future Gas Supply (Note 1)	91.0	42.5
Investments		
Pipelines (Note 2)	441.5	394.9
Natural resources (Note 3)	894.6	740.6
	1,336.1	1,135.5
Plant, Property and Equipment — at cost	3,335.9	3,266.8
Less accumulated depreciation	707.6	616.0
	2,628.3	2,650.8
Deferred Charges	81.6	72.1
	5,034.5	4,716.9
Liabilities and Shareholders' Equity		
Current Liabilities		
Notes payable	285.5	200.0
Accounts payable	524.5	642.7
Interest accrued	119.2	96.5
Dividends payable	31.1	23.5
Long-term debt due within one year	53.4	41.3
	1,013.7	1,004.0
Long-Term Debt (per Schedule and Note 4)	2,218.0	2,152.9
Deferred Income Taxes	377.8	297.3
Shareholders' Equity		
Capital stock (Note 5)	468.7	452.7
Contributed surplus	275.9	275.5
Retained earnings	658.6	534.5
Foreign exchange adjustment (Note 10)	21.8	—
	1,425.0	1,262.7
	5,034.5	4,716.9

On behalf of the Board:

G. P. Osler, Director

R. R. Latimer, Director

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

Consolidated Contributed Surplus and Retained Earnings

Year ended December 31, 1983

(stated in millions of dollars with comparative figures for 1982)	1983	1982
Contributed Surplus		
Balance at beginning of year	275.5	274.7
Credit resulting on redemption of preferred shares	.4	.8
Balance at end of year	275.9	275.5

	1983	1982
Retained Earnings		
Balance at beginning of year	534.5	426.4
Net income for the year	228.1	198.9
	762.6	625.3
Dividends declared		
Preferred	36.3	37.8
Common	67.7	53.0
	104.0	90.8
Balance at end of year	658.6	534.5

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

Consolidated Source of Funds for Capital Expenditures

Year ended December 31, 1983

(stated in millions of dollars with comparative figures for 1982)	1983	1982
Funds Generated		
Net income	228.1	198.9
Depreciation	97.9	77.0
Deferred income taxes	82.3	53.7
Equity in undistributed income from investments net of funds generated	45.3	28.3
Other	(59.3)	(31.6)
Funds generated by operations and equity investments	394.3	326.3
Less funds generated by equity investments in unincorporated joint ventures	82.3	82.0
Funds generated by operations	312.0	244.3
Funds received from take or pay refinancing	36.0	981.5
Less:		
Dividends on preferred and common shares	104.0	90.8
Reduction of long-term debt	154.0	865.5
Net funds generated	90.0	269.5
Funds from New Financing		
Long-term debt	234.0	797.5
Common shares	17.1	7.2
	251.1	804.7
Less refinancing	—	230.0
Net funds from new financing	251.1	574.7
Funds from Other Sources (net)		
Change in working capital	(71.8)	38.1
Deferred charges and other	34.0	(49.3)
	(37.8)	(11.2)
Funds Available for Capital Expenditures	303.3	833.0

Capital Expenditures		
Plant, property and equipment	75.8	772.5
Investments — pipelines	13.4	26.9
— natural resources	129.6	22.9
Payments on future gas supply	84.5	10.7
Total Capital Expenditures	303.3	833.0

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

Consolidated Schedule of Long-Term Debt

December 31, 1983

(stated in millions of dollars with comparative figures at December 31, 1982)	1983	1982
First Mortgage Pipe Line Bonds		
Due 1983 — 6¼% U.S. series	—	5.5
— 6¾% Canadian series	—	2.1
Due 1985 — 5⅝% U.S. series — U.S. $4,160,000	4.8	7.2
Due 1987 — 7⅛% U.S. series — U.S. $29,280,000	32.6	39.8
Due 1992 — 9¼% Canadian series A	49.6	54.3
— 9¼% Canadian series B	21.0	23.2
Due 1993 — 8⅞% Canadian series A	34.8	38.4
— 8⅞% Canadian series B	5.5	6.1
Due 1996 — 16% U.S. series — U.S. $400,000,000	483.2	482.8
Due 1997 — 16¾% U.S. series — U.S. $125,000,000	158.2	158.1
Due 2007 — 16½% U.K. series — £25,000,000	54.7	54.7
	844.4	872.2
Debentures		
Due 1990 — 10% series A	25.8	29.7
— 9¾% series B	32.0	37.2
Due 1991 — 9% series C	25.5	29.7
Due 1992 — 8⅞% series D	59.8	67.8
Due 1993 — 9% series E	63.1	72.9
Due 1995 — 11½% series F	38.5	41.7
Due 1997 — 9.60% series G (Sinking fund commenced in 1983)	58.7	63.4
Due 1996 — 18% series H (Sinking fund commences in 1987)	75.0	75.0
Due 1993 — 11.70% series I	100.0	—
	478.4	417.4
Notes		
Due 1986 — 5¾% — Swiss francs 100,000,000	57.1	61.1
Due 1987 — 6% — Swiss francs 50,000,000	28.6	30.6
Due 1989 — 7¼% — Swiss francs 50,000,000	28.6	30.6
Due 1991 — 5½% — Swiss francs 100,000,000	57.1	61.1
Due 1993 — 5¾% — Swiss francs 100,000,000	57.1	—
Due 1994 — 7% — Swiss francs 100,000,000	57.1	61.1
Due 1988 — 17¾% — U.S. $75,000,000	90.0	90.0
Due 1989 — 16% — U.S. $100,000,000	118.1	118.1
Due 1992 — 16% — U.S. $97,810,000	119.3	119.3
	613.0	571.9
Term Loans		
Due 1983 — 1986 — Canadian series	161.0	163.0
Due 1987 — U.S.	—	71.1
Due 1984 — 1988 — 6⅞% — Swiss francs 50,000,000	28.6	—
— 7⅞% — Dutch guilders 120,000,000	48.7	—
	238.3	234.1
Term Promissory Notes		
Due 1985 — 1986 — 15½% U.S. series — U.S. $20,000,000	24.9	24.6
Due 1986 — 15½% Canadian series	5.0	5.0
Due 1987 — 17⅜% U.S. series — U.S. $25,000,000	31.1	30.7
	61.0	60.3
Subordinated Debentures		
Due 1987 — 5.60% U.S. series — U.S. $9,654,000	9.7	11.3
— 5.85% Canadian series	26.6	27.0
	36.3	38.3
	2,271.4	2,194.2
Less long-term debt due within one year	53.4	41.3
	2,218.0	2,152.9

See Note 4 to consolidated financial statements.

Summary of Significant Accounting Policies

December 31, 1983

The Company owns a natural gas transmission system extending from Alberta to Quebec, and purchases, transports and sells natural gas to customers in Canada and the United States. The Company also has equity investments in gas transmission system joint ventures and oil and gas exploration and production joint ventures in Canada, the United States and other countries.

The consolidated financial statements of the Company have been prepared by management in accordance with accounting principles generally accepted in Canada. These principles also conform in all material respects with International Accounting Standards on an historical cost basis. The significant accounting policies are summarized below:

Principles of consolidation — The consolidated financial statements include the accounts of the Company and its subsidiaries, all of which are wholly owned.

Investments — The Company uses the equity method of accounting for its investments in incorporated and unincorporated joint ventures. Under this method, investments are initially recorded at cost and are subsequently adjusted to include the Company's pro rata share of the investees' earnings. Dividends received by the Company reduce the carrying value of the investment.

Investments in other companies over which the Company does not have significant influence are carried at cost.

The Company uses the full cost method of accounting for its oil and gas joint venture operations whereby all costs of exploring for and developing oil and gas and related reserves are capitalized in a single cost centre. Such costs include all acquisition, exploration and development costs, including interest and other carrying charges of non-producing properties and costs of drilling both productive and non-productive wells. The amount of costs that have been capitalized do not exceed the recoverable value of the underlying interests in oil and gas properties.

Depletion is provided using the revenue method, whereby provisions for depletion are calculated for individual periods in the same proportion as current production revenues are to total estimated revenues from proved reserves. Costs of unusually significant acquisitions of non-producing properties are initially not depleted and are brought into the cost centre for depletion purposes on a straight-line basis over the anticipated period that exploration of those properties will be undertaken.

Interest is capitalized on unusually significant acquisitions of unproven oil and gas properties until such time as development activities have proceeded to the point where proved reserves are capable of being produced or it is determined there are no economic proved reserves associated with the properties. Interest is also capitalized on unusually significant acquisitions of oil and gas properties which, at the date of acquisition, were capable of but had not commenced production. Capitalization of interest on these properties is terminated when production commences.

Regulation — Matters such as tolls, construction, operations and accounting in connection with the Company's natural gas transmission system are subject to the jurisdiction of certain regulatory bodies. Utility tolls are determined by the National Energy Board ("NEB") on a net plant rate base, rate of return and cost of service basis. By order dated June 28, 1983, the NEB authorized an increase in the Company's tolls effective August 1, 1983, which included an increase in the Company's overall rate of return on rate base to 14.00% from 13.88%. The current rate of return on rate base reflects a rate of return of 15% on a deemed common equity ratio of 28%.

The gas transmission system joint ventures in which the Company holds an equity investment are also regulated with respect to similar matters.

As approved by various regulatory authorities, an Allowance for Funds Used During Construction ("AFUDC") is capitalized for both Canadian and United States pipeline projects. The rate used in calculating this allowance is adjusted from time to time to reflect the estimated cost of capital employed.

The North Bay Shortcut was constructed in 1982 to connect with the existing pipeline. To accommodate the objective of the Federal Government's price restraint program announced in June 1982 and in recognition of the gradual build up of deliveries through the North Bay Shortcut, the Company proposed to the NEB that it defer a portion of the return on rate base associated with these facilities that would otherwise have been recovered in tolls for the period August 1983 to July 1984. This was done to maintain the recovery of the return on rate base and associated income taxes at the level included in the tolls for the period to July 1983. The proposal was approved by the NEB and the amount so deferred will be amortized and recovered in tolls together with carrying costs over a three year period commencing August 1, 1984. The amount deferred to December 31, 1983 is approximately $19 million.

Plant, property and equipment — Depreciation relating to the gas transmission system is calculated on a straight-line basis using rates reflecting the economic and physical life of the assets in service. These rates are approved by the NEB in accordance with its policy of permitting the recovery of undepreciated plant costs over the estimated remaining service life of the assets as determined from time to time. Depreciation is calculated using rates of 2¾% for pipeline, 3½% for compressor stations and other transmission plant and various rates for general plant equipment.

Translation of foreign currency — The Company changed its accounting policy with respect to foreign currency translation prospectively from January 1, 1983 as discussed in Note 10.

The accounts of foreign operations are translated into Canadian dollars on the following basis: Assets and liabilities are translated using exchange rates at the balance sheet date; translation adjustments are reflected in a separate component of shareholders' equity; revenue and expense items are translated using the average rates of exchange during the year.

Transactions in a currency other than a domestic currency are translated into that domestic currency using the temporal method as follows: At the transaction date, each asset, liability, revenue or expense is translated using exchange rates in effect at that date. At each balance sheet date, monetary assets and liabilities are translated using exchange rates at that date. Foreign exchange gains and losses on utility related debt are deferred and included in net income as they are dealt with in the ratemaking process. Other foreign exchange gains and losses are included in income in the current period except for unrealized gains and losses related to monetary assets and liabilities with a fixed or ascertainable life extending beyond one year. These unrealized gains and losses are deferred and amortized to income over the remaining life of such assets or liabilities.

Income taxes — For all operations other than those subject to the jurisdiction of Canadian regulatory authorities, the Company follows the deferral method of tax allocation accounting under which full provision is made for income taxes based on accounting income of these operations. This provision differs from income taxes currently payable as certain items of income and expense are included in accounting income in years different from those in which they are reported in taxable income.

For the Canadian utility operations, the method of accounting for income taxes is as prescribed by the NEB for ratemaking purposes. The deferral method of tax allocation accounting was prescribed for the period from August 1, 1978 to July 31, 1982 and the deferred taxes so recovered in rates totalled approximately $76 million. This amount is included in Deferred Income Taxes in the Statement of Financial Position. Prior to August 1, 1978 and subsequent to July 31, 1982, the NEB prescribed the taxes payable method of accounting for income taxes for such operations. If the deferral method of tax allocation accounting had been permitted and applied retroactively for all periods by the NEB for ratemaking purposes, additional income taxes would have been recorded to an accumulated amount of approximately $310 million and recovered in revenues during those periods.

Since there is reasonable expectation that all income taxes payable by the Company related to its Canadian utility operations will be included in the future cost of service and recovered in revenues at that time, the Company is following the taxes payable method at this time for both accounting and ratemaking purposes for such operations.

1. Payments on Future Gas Supply

The Company purchases gas from approximately 650 producers under a total of approximately 2,300 gas purchase contracts. Substantially all of these contracts have provisions requiring payments by the Company when it is unable to nominate for delivery specified minimum annual quantities of gas. As the contracted supply has exceeded the available market in recent years, payments ("take or pay payments") were made by the Company for gas not taken ("prepaid gas").

During 1982 and 1983, the Company concluded arrangements to refinance its take or pay payments with several syndicates of Canadian and foreign banks and substantially all of its producers, herein referred to as the Topgas Programs. Separate companies (the "Topgas Companies"), which are controlled by the banking syndicates, were incorporated as financing vehicles.

By the end of 1982, the first Topgas Company had advanced to producers approximately $2.3 billion representing substantially all of the amounts that had been paid by the Company or were payable by the Company in respect of take or pay obligations. Amounts previously advanced by the Company were refunded to the Company.

During the 1981/82 contract year, TransCanada nominated for delivery approximately 67% of its minimum annual obligation. Under the first Topgas Program, the Company's future obligation to make take or pay payments under substantially all of its gas purchase contracts would arise only if the Company was unable to nominate 60% of the minimum annual obligation for the 1981/82 contract year.

During the 1982/83 contract year, TransCanada was able to nominate only 48% of its minimum annual obligation. This shortfall below the 60% level established under the first Topgas Program would have required take or pay payments by the Company of approximately $360 million for the 1982/83 contract year. The Company made a further proposal to all of its producers for a new program, the second Topgas Program, under which the take or pay payments for the 1982/83 contract year would be paid by the second Topgas Company and which further provided for a reduction of the minimum annual obligation to 50% for the 1983/84 contract year and for a level between 50% and 60% in future years, depending on actual delivery levels in the immediately preceding two years. This proposal has been accepted and implemented for approximately 82% of the contracted supply, resulting in total payments of approximately $275 million being made by the second Topgas Company for the 1982/83 contract year. For those producers that have not yet accepted this proposal, representing payments of approximately $85 million, a second closing is scheduled for March 1984. The Company anticipates that additional amounts will be refinanced under the second Topgas Program at that time.

Recovery of the amounts advanced to producers under the Topgas Programs will be effected in instalments commencing November 1, 1984, through the nomination for delivery by the Company of prepaid gas. Upon recovery of prepaid gas, the Company will pay directly to the Topgas Companies the amount which the Topgas Companies paid to the producers in respect of the equivalent volume of prepaid gas. The balance of the purchase price, if any, will be paid to the producers. The scheduled recovery of prepaid gas under a gas purchase contract in any contract year for the first Topgas Program is 10% of the outstanding balance as at December 31, 1982 and for the second Topgas Program is 10% of the outstanding balance as at December 31, 1983. The recovery of prepaid gas will be accelerated if total sales of gas by the Company exceed specified levels in the future.

Under the Topgas Programs, the Company will indemnify the Topgas Companies to a combined maximum of $360 million for, in effect, any losses arising due to the inability or failure of a producer to deliver prepaid gas. The Company will also indemnify the Topgas Companies for any losses suffered as a result of a failure or breach by the Company of its obligations under the Topgas Programs, or by reason of the failure of the Topgas Companies to recover their interest costs in the Company's Alberta Cost of Service or from any other source.

The Company continues to make direct take or pay payments under a small number of gas purchase contracts to certain producers who could not or did not wish to participate in the Topgas Programs.

The interest costs associated with the funds advanced by the Topgas Companies to the producers are being included in the Company's Alberta Cost of Service and remitted to the Topgas Companies by the Company. Interest on term loans and dividends on preferred shares related to the financing of prepaid gas prior to the implementation of the Topgas Programs and the cost of funds relating to advances made by the Company directly to those producers not in the Topgas Programs, have also been recovered in the Company's Alberta Cost of Service. These recoveries have been deducted from "Cost of gas sold" in the statement of Consolidated Income. Interest costs for advance payments made directly by the Company have been recovered in the approximate amounts of $3 million and $96 million for the years ended December 31, 1983 and 1982 respectively. For the year ended December 31, 1982, preferred dividends of $24 million and related income taxes were recovered through the Alberta Cost of Service.

As a result of significant deterioration in their markets, the Company's three largest United States pipeline customers, including Great Lakes Gas Transmission Company ("Great Lakes") were not able to nominate for delivery the minimum volumes of natural gas which they are required to take or in any event pay for under their existing gas purchase contracts.

During the contract year ended October 31, 1983, these contracts stipulated a minimum take or pay obligation of 75% of the customers' total annual volume entitlement.

In the Company's opinion, to insist on compliance in full with these provisions might have resulted in United States regulatory or legislative initiatives which might be adverse to the long-term interests of the parties to these contracts. Accordingly, to achieve a mutually agreeable short-term solution to its customers' problems, the Company has entered into amending agreements with Great Lakes and one of the other two customers which revise the take or pay obligations for a substantial portion of their contracted volumes as follows:

(a) The take or pay obligation for the 1982/83 contract year is reduced to 50% from 75% of annual entitlement.

(b) For the 1983/84 and succeeding contract years, the buyers are obliged to "take and pay" for 50% of annual entitlement. "Take and pay" means that failure to take the minimum take and pay volume will require prompt payments following the end of the contract year for the deficient volume at the full export border price, without any right of make up respecting the deficient volume. This provision should ensure takes of gas at no less than the minimum annual level.

(c) For the 1985/86 and succeeding contract years, the original 75% take or pay obligation is reinstated, but the take and pay 50% obligation continues in effect. Takes in excess of the 50% take and pay level apply to reduce prior take or pay deficiencies.

(d) Take or pay payment obligations may be deferred for four years, with interest payable monthly at a rate equal to the prime rate of a Canadian chartered bank plus 1%.

(e) Either party, on at least 6 months' notice to the other, may terminate the foregoing amendments and reinstate the original contract provisions effective as of the first day of any contract year on or after November 1, 1986.

These amending agreements are subject to the obtaining of required regulatory approvals. All such approvals have been obtained except for United States Federal Energy Regulatory Commission authorizations required by Great Lakes, which are pending.

The Company has also recently reached agreement with the remaining affected customer to enter into similar amendments, subject to the obtaining of required regulatory approvals. Should these be obtained and the amendments become effective, the total principal amount of the take or pay obligations owed to the Company by these three customers as at December 31, 1983 (including take or pay payments incurred in respect of the contract year ended October 31, 1982 and previously deferred on similar terms) will be approximately $266 million.

The take or pay obligations deferred in accordance with the aforementioned amendments may be reduced during the deferral period by the sale and delivery to the customers of volumes of gas in addition to their current minimum contractual commitments, as make up of the volume deficiencies previously incurred.

Because the Company expects the customers to make up the deficient volumes prior to expiration of their contracts, these gas sales rights and obligations are considered to be offsetting and have been so dealt with in the Consolidated Statement of Financial Position. The interest received from these customers on the deferred obligations will be applied to reduce the Company's Alberta Cost of Service.

The Company has made arrangements with another customer, which purchases gas for resale to United States markets, to provide relief for take or pay obligations incurred to date. Although these arrangements are subject to regulatory approval, gas sales rights and obligations to October 31, 1983 of approximately $89 million, determined under present contract provisions, are also offsetting and have been so treated in the financial statements.

2. Investments — Pipelines

The investment in regulated pipeline joint ventures at December 31, 1983 and 1982 and the Company's share of the earnings of those ventures for the years then ended are:

	1983		1982	
	Investment	Equity Earnings	Investment	Equity Earnings
	(millions of dollars)			
Great Lakes Gas Transmission Company:				
—shares	68.2	9.8	47.4	15.4
—loan, due 1986, interest bearing	62.2	—	61.5	—
Alaska Natural Gas Transportation System:				
—Northern Border Segment	179.4	59.0*	175.9	21.8*
—Alaska Segment	25.8	—	24.3	(1.9)
—Canadian Segment (Saskatchewan section)	31.2	5.7	33.5	5.6
Trans Québec & Maritimes Pipeline	74.7	10.1	52.3	12.0
	441.5	84.6	394.9	52.9

*On January 1, 1983 Northern Border's full cost of service tariff went into effect and 1983 equity earnings reflect the Company's proportionate share of income on a pre tax basis. 1982 equity earnings represent the Company's share of Northern Border's equity AFUDC which is computed on an after tax basis.

Great Lakes Gas Transmission Company

The Company shares equally with American Natural Resources Company in the ownership of Great Lakes which is incorporated in the United States. Great Lakes transports a substantial volume of gas for the Company through the United States for sale by the Company in eastern Canada and purchases natural gas from the Company for sale to customers in the United States.

The following sets out summarized financial information for Great Lakes:

	1983	1982
	(millions of U.S. dollars)	
Natural gas transmission plant (net)	323.5	333.4
Current liabilities less current assets	(7.5)	(36.7)
Deferred credits (net)	(56.1)	(39.7)
Long-term debt	(148.1)	(162.7)
Shareholders' equity	111.8	94.3
Revenues	312.3	536.4
Expenses	(294.8)	(511.4)
Net income	17.5	25.0

Alaska Natural Gas Transportation System ("ANGTS")

ANGTS contemplates the construction of a pipeline extending from Prudhoe Bay on Alaska's North Slope across Alaska and Canada into the United States. In southern Alberta, the route divides into two legs. The western leg carries gas to western United States markets and terminates near San Francisco, California. The eastern leg travels through Alberta and southwestern Saskatchewan carrying gas to mid-western, eastern and southern United States markets and will terminate near Dwight, Illinois. ANGTS will also include a major gas conditioning plant at Prudhoe Bay, Alaska.

ANGTS is being built as four separate but integrated pipeline segments herein referred to as the "Alaska segment", the "Canadian segment", the "Northern Border segment" and the "Western segment", respectively. The Company has no participation interest in the Western segment.

The Company's participation in ANGTS is set out below:

(a) Northern Border Segment

The Company has a 30% interest in the partnership which constructed the First Phase of the natural gas pipeline extending from Monchy, Saskatchewan to a point near Ventura, Iowa (the "First Phase"). On September 1, 1982, construction of the First Phase was completed at a total cost of (U.S.) $1.3 billion. All revenues and expenses were capitalized in regard to the First Phase until January 1, 1983, the date a full cost of service tariff went into effect. Final approval by the Federal Energy Regulatory Commission of Northern Border's Incentive Rate of Return, expected to be approximately 17%, is pending.

The Company also has the right to acquire at least a 17½% interest in the Second Phase which contemplates the extension of the pipeline to the vicinity of Dwight, Illinois (the "Second Phase"). Construction of this phase of the project has been deferred as a result of the uncertain demand for natural gas in the United States.

Pursuant to the agreement to acquire its interest in the First Phase, the Company entered into a transportation service agreement for the delivery of sufficient quantities of Canadian gas to support the financing of the First Phase. Under this agreement, the Company has the right to have up to 8 billion cubic metres of gas transported for it annually but will be required to pay minimum monthly fixed charges regardless of the actual volumes transported. This right is subject to a prior right of other shippers to have Canadian or Alaska gas transported for sale in the United States. When authorized exports terminate, the requirement to pay a minimum bill could result in the Company being required to pay the cost of service charges of the First Phase. If at the end of the tenth year of operation of the First Phase the decision has not been taken to construct the Second Phase and if at that time the only gas being transported through the First Phase is Canadian gas destined for customers of the Company in eastern Canada, the Company shall be obligated and shall have the right to purchase the First Phase at, in effect, the fair market value thereof at that time.

The debt financing for construction of the First Phase was provided by a syndicate of banks, in a total amount of (U.S.) $874 million. In connection with such financing, the Company has entered into a collateral agreement under which it may be required to make available to the partnership: (i) funds sufficient to enable the partnership to reduce the outstanding balance of the loan at final maturity in 1993 to 40% of the total advances if, after six years of operation of the First Phase, the Company is not able to arrange additional volumes of gas to provide revenues to reduce such outstanding balance accordingly; and (ii) if the loan is not fully paid at maturity or upon the happening of specified earlier events, funds in an amount equal to the greater of the outstanding balance of the loan or the depreciated cost of the business and assets of the partnership.

The following sets out summarized financial information for the Northern Border Partnership:

	1983	1982
	(millions of U.S. dollars)	
Natural gas transmission plant (net)	1,199.1	1,299.1
Current liabilities less current assets	(23.3)	(42.0)
Deferred credits (net)	(59.8)	5.3
Long-term debt	(696.8)	(781.1)
Partners' equity	419.2	481.3
Revenues	351.7	–
Expenses	(205.5)	–
Equity AFUDC	.4	53.8
Income before income taxes	146.6	53.8

(b) Alaska Segment

It is currently proposed that the Alaska segment, including a gas conditioning plant, will be constructed, owned and operated by a partnership of nine major natural gas transmission companies and three major oil companies. The Company expects to acquire a 7% partnership interest in the Alaska segment. The Company may adjust its partnership interest in the project once financing arrangements have been completed. Due to economic factors beyond the control of the partnership,. including excess world energy supply, depressed crude oil prices, low levels of worldwide economic activity and uncertainties in financial markets, completion of the Alaska segment is not anticipated before 1990. The ultimate realization of the Company's investment in the Alaska segment is dependent upon final governmental and regulatory authorizations and cost approvals, satisfactory gas purchase, sale and transportation contracts, adequate financing and successful completion of construction.

The following sets out summarized financial information for the Alaska segment partnership:

	1983	1982
	(millions of U.S. dollars)	
Natural gas transmission plant under construction	424.3	382.1
Current assets less current liabilities	2.3	(.4)
Deferred charges	1.1	.3
Other liabilities	(55.4)	(63.5)
Partners' equity	372.3	318.5

(c) Canadian Segment (Saskatchewan section)

The Company has a 44% interest in Foothills Pipe Lines (Sask.) Ltd. ("Foothills (Sask.)"), which owns the Saskatchewan section of the Canadian segment of ANGTS. This pipeline extends from the Alberta/Saskatchewan border near Empress, Alberta to the Canada/United States border near Monchy, Saskatchewan to connect with the Northern Border segment. Foothills (Sask.) began operations in September 1982 in conjunction with the start-up of the Northern Border segment. The Company operates this pipeline on behalf of Foothills (Sask.).

The following sets out summarized financial information for Foothills (Sask.):

	1983	1982
	(millions of dollars)	
Natural gas transmission plant (net)	349.8	326.6
Current liabilities less current assets	(23.9)	(18.9)
Deferred amounts	(15.4)	(2.3)
Long-term debt	(232.0)	(221.8)
Shareholders' equity	78.5	83.6
Revenues	68.7	14.8
Expenses	(59.1)	(37.1)
AFUDC	3.4	33.7
Net income	13.0	11.4

Trans Québec & Maritimes Pipeline

Each of the Company and Nova, an Alberta Corporation, own 50% of Trans Québec & Maritimes Pipeline Inc. ("TQM") which owns and operates a natural gas transmission system from the vicinity of Montreal to Quebec City.

The NEB has authorized TQM to operate on a cost of service basis and, for the six months ended December 31, 1983, to earn a rate of return on rate base of 12.9% which reflects a rate of return of 15.6% on a deemed common equity ratio of 25%. Prior thereto, TQM's rate of return permitted the recovery of its cost of debt and 15.75% on common equity. On January 11, 1984, a new hearing commenced to examine TQM's proposed tariff for its 1984 tolls.

The following sets out summarized financial information for TQM:

	1983	1982
	(millions of dollars)	
Natural gas transmission plant (net)	460.8	379.8
Current assets less current liabilities	12.1	(20.1)
Deferred charges	6.1	10.9
Bank loan	(329.6)	(266.0)
Partners' equity	149.4	104.6
Revenues	71.8	22.0
Expenses	(61.0)	(19.2)
AFUDC	9.4	21.2
Net income	20.2	24.0

3. Investments — Natural resources

The investment in producing and non-producing oil and gas operations and other natural resource investments at December 31, 1983 and 1982 and the Company's share of the earnings for the years then ended are:

	1983		1982	
	Investment	Equity Earnings	Investment	Equity Earnings
	(millions of dollars)			
Canadian Operations	722.5	12.4	588.1	29.8
United States Operations	107.5	2.3	87.2	(1.3)
Other Foreign Operations	64.6	7.0	65.3	1.6
	894.6	21.7	740.6	30.1

Until March 10, 1982, essentially all borrowings relating to natural resources investments were made directly by the Company and the costs related thereto were included in Financial Charges in the statement of Consolidated Income. After the Hudson's Bay Oil & Gas Company Limited ("HBOG") acquisition, a substantial portion of such borrowings was arranged through the partnership with Maligne Resources Limited ("Maligne") and the associated interest charges have been deducted in computing Income from Investments — Natural resources in the statement of Consolidated Income. If all borrowings had continued to be made directly by the Company, Income from Investments — Natural resources would have been $64 million and $59 million and Financial Charges $333 million and $397 million for 1983 and 1982, respectively.

Canadian Operations

The majority of the Company's properties are located in the Province of Alberta and were held at December 31, 1983 by a partnership of the Company and Maligne. Each company has rights and obligations under a participation agreement with Dome Petroleum Limited ("Dome"), dated December 1, 1979, which provides for, among other things, a 25% participation by the partnership in Dome's onshore property acquisitions since that date in a defined area which encompasses primarily the four western provinces, the Yukon and Northwest Territories. In 1982, the Company acquired from Dome for approximately $560 million, a 12½% undivided interest in substantially all of the assets of HBOG. These assets included oil and gas holdings, both foreign and domestic, and interests in domestic mining properties. In 1983, Dome entered into a major farmout agreement with Home Oil Company Limited which provides for significant expenditures over a period at least until 1986 on Dome's properties, including those in the defined area. Under the participation agreement, Dome has the right to acquire, at cost, a 75% participation in any oil and gas interest acquired by the Company within the defined area. The Company also has interests in oil and gas permits in the Beaufort region and the East Coast offshore area.

Through the partnership with Maligne, the Company arranged bank loans to cover the purchase price of a substantial portion of the properties. These bank loans are secured by the Company's interest in certain producing properties and are non-recourse to the Company. The Company's investment at December 31, 1983 and 1982 reflects the cost of these properties net of these non-recourse bank loans.

The Company owns a 12½% interest in certain mining properties including Cyprus Anvil Mining Corporation ("Cyprus") whose operations were suspended in 1982. In the fall of 1983, a plan involving the Government of Canada and Dome was implemented for removal of overburden from the ore body. The ultimate realization of the Company's investment of $31.9 million in Cyprus is dependent upon resumption of profitable operations which is itself dependent upon Cyprus reducing certain operating expenses, obtaining satisfactory capital financing, and upon improved mineral market conditions and general economic conditions.

United States Operations

The Company holds a number of oil and gas properties acquired from Dome together with properties acquired under other arrangements.

Other Foreign Operations

The Company has interests in foreign oil and gas concessions formerly owned by HBOG and acquired from Dome, the most significant of which are located in Indonesia.

The following sets out summarized financial information of the Company's proportionate share of natural resources ventures:

	1983	1982
	(millions of dollars)	
Oil and gas properties — at cost	1,435.1	1,340.8
Accumulated depreciation, depletion and amortization	(98.2)	(50.1)
Mining properties and investments	49.3	49.5
Extraction plant — at equity	67.8	—
Current liabilities less current assets	(58.3)	(2.1)
Long-term debt	(501.1)	(597.5)
Net investment	894.6	740.6
Revenues	214.2	189.6
Operating expenses	(192.5)	(159.5)
Income from operations	21.7	30.1

In 1983 and 1982, interest of $30.3 million and $57.6 million, respectively, was capitalized in connection with oil and gas properties.

4. Long-Term Debt

First Mortgage Pipe Line Bonds

The Deed of Trust and Mortgage securing the Company's first mortgage pipe line bonds provides for a first charge upon all the real and immovable property and rights of the Company and upon substantially all of the Company's gas transportation, gas purchase, gas sales and gas product sales contracts. It also provides for a first floating charge on all the remaining assets. All series of bonds, with the exception of the 16½% U.K. series, are subject to mandatory sinking fund provisions which require the Company to retire stated amounts for each series during prescribed periods prior to maturity.

Debentures

All series of sinking fund debentures are subject to mandatory sinking fund provisions. The terms of the Series A to G sinking fund debentures provide for an annual purchase fund equal to 3% of the aggregate principal amount of debentures outstanding on July 10, 1981. Pursuant to these requirements, debentures are being purchased, to the extent that they are available, at prices, including costs of purchase, that do not exceed the principal amount plus accrued interest to the date of purchase. The purchased debentures are delivered to the Trustee for cancellation. In 1983, the Company issued the Series I debentures which rank equally with the sinking fund debentures.

Term Loans, Promissory Notes and Notes

The notes payable, the Canadian series term loans and the term promissory notes rank equally with the sinking fund debentures and prior to the subordinated debentures. The Swiss franc and Dutch guilder term loans are debt of a subsidiary and are secured by the Company's interest in the Northern Border partnership. These instruments contain various covenants which, in certain instances, allow prepayments without bonus or penalty. The Canadian series term loans bear interest at floating rates approximating Canadian chartered bank prime rates.

In addition to purchase fund requirements, mandatory retirements of long-term debt as a result of maturities and sinking fund obligations approximate $53.4 million for 1984, $97 million for 1985, $335.7 million for 1986, $195 million for 1987 and $251.8 million for 1988.

5. Capital Stock

The details of the Company's capital stock, all classes of which are without par value, and changes in the number and dollar value of shares outstanding during 1983, are:

	Authorized and Outstanding December 31, 1982		Issued for Cash		Purchase, Retraction and/or Conversion of Preferred Shares		Authorized and Outstanding December 31, 1983	
Issue	Shares	Amount*	Shares	Amount*	Shares	Amount*	Shares	Amount*
First Preferred Shares								
Cumulative redeemable								
–$2.80	660,346	33.0			(20,970)	(1.0)	639,376	32.0
Cumulative redeemable retractable								
–$4.50 Series B	944,840	47.2			(3,200)	(.1)	941,640	47.1
–Series D	2,200,000	110.0					2,200,000	110.0
–Series E	1,500,000	75.0					1,500,000	75.0
–Series F	1,600,000	80.0					1,600,000	80.0
		345.2		–		(1.1)		344.1
Common Shares	44,789,851	107.5	670,049	17.1**		–	45,459,900	124.6
Capital Stock		452.7		17.1		(1.1)		468.7

*Dollar value stated in millions of dollars

The authorized number of cumulative redeemable first preferred and second preferred shares issuable in series and common shares is unlimited.

** Common shares issued for cash

	Shares	Amount (millions of dollars)
Under the dividend reinvestment and share purchase plan	313,438	8.2
Under the stock dividend and share purchase plan	30,511	.8
Under employee stock purchase plans	326,100	8.1
	670,049	17.1

Purchase Funds

The Company is required to set aside on its books a purchase fund account for the $2.80 first preferred shares. Subject to certain conditions, this account is adjusted annually on February 1, to an amount equal to 2% of the aggregate stated capital amount of the shares outstanding on the previous December 31.

For the $4.50 retractable first preferred shares, the Company is required to set aside on its books on each February 1 until 1984, a purchase fund account equal to the lesser of $1.5 million and the aggregate stated capital amount of the shares outstanding on the previous December 31. Thereafter, subject to certain conditions, the purchase fund account is adjusted annually on February 1, to an amount equal to 3% of the aggregate stated capital amount of the shares outstanding on the previous December 31.

The purchase funds for the series F preferred shares commence on June 1, 1984 and for the series D and series E preferred shares commence in 1986 and 1990, respectively. Such purchase funds will be adjusted annually to an amount equal to 3% of the aggregate stated capital amount of the shares outstanding at a specified date for each series.

The various purchase funds are applied, subject to certain conditions, to purchase preferred shares for cancellation to the extent, if any, that such shares are available at a price not exceeding $50.00 per share plus costs of purchase.

Redemptions and Retractions

The Company has the option, subject to certain conditions, to redeem the preferred shares at the following premiums plus accrued and unpaid dividends:

a) $2.80 first preferred shares
 — a premium of $0.50 per share
b) retractable first preferred shares
 — at various premiums of up to $5.16, reducing in progressive steps to nil over periods to 1989

The retractable first preferred shares have a retraction feature which requires the Company, subject to certain conditions, to invite tenders for the purchase of all such shares on the specified dates set out in the table below at the stated value plus accrued and unpaid dividends. With the exception of the $4.50 retractable first preferred shares, the Company may increase the dividend rate on such shares effective on each retraction date.

Preferred Share Dividend Rates and Retraction Dates

The current dividend rate of the retractable first preferred shares and the retraction dates are:

Series	Current Dividend Rate	Retraction Dates
$4.50 Series B	$4.50	January 31, 1985
Series D	$5.00	November 1, 1985
Series E	$5.16	November 1, 1984 and 1989
Series F	$7.18	May 1, 1984 and 1988

Dividend Reinvestment, Stock Dividend and Share Purchase Plans

On December 1, 1982, the Company's Board of Directors authorized a dividend reinvestment and share purchase plan and a stock dividend and share purchase plan. The dividend reinvestment and share purchase plan provides an opportunity for holders of the Company's common and preferred shares to purchase additional common shares to be issued from treasury with reinvested cash dividends at 95% of a specified average market price. Under the stock dividend and share purchase plan, common shareholders may elect to receive stock dividends in common shares in lieu of cash dividends. New common shares received as stock dividends will be issued at 95% of a specified average market price. Participants in both plans may also make cash payments of up to $3,000 per quarter for the purchase of additional common shares of the Company at 100% of a specified average market price.

Common Shares Reserved

At December 31, 1983, 401,803 common shares were reserved for issuance upon exercise of options granted or which may be granted under the terms and conditions of the Company's employee stock purchase plans.

Interest Free Loans

Interest free loans amounting to approximately $25 million at December 31, 1983, which are repayable after a maximum period of 10 years, have been made to certain key employees, some of whom are also directors, to purchase shares of the Company under certain stock purchase plans.

6. Restriction on Dividends

Declaration of dividends on both preferred and common shares is restricted under certain preferred share provisions and under several debt instruments. At December 31, 1983, under the most restrictive provisions, approximately $72 million was available for the payment of dividends on common shares.

7. Pending Proceedings

Under a contract dated November 1, 1969, between Saskatchewan Power Corporation ("Sask Power") and the Company, Sask Power was granted an option to purchase certain quantities of gas at a stipulated price (the "contract price") during a seven-year period commencing in 1974.

By amendments to the Natural Gas Prices Regulations made under the Energy Administration Act (the "EAA") (formerly the Petroleum Administration Act), prices were prescribed for the sale of natural gas in all of the Company's sales zones in Canada during the period in question, including the sales zone relevant to the sale to Sask Power above described, and such rates were higher than the contract price.

On November 29, 1979, Sask Power commenced an action against the Company in the Saskatchewan Court of Queen's Bench to recover monies alleged to be owed to it by the Company as a result of overpayments made under protest for gas sold under such contract.

The overpayments claimed to October 1980 amounted to $59.2 million plus accrued interest.

The Company has filed a defence to such action relying on the provisions of the EAA. Counsel to the Company is of the opinion that the Company has a good defence which should prevail in the action.

8. Related Party Transactions

Through two public secondary offerings in 1983, Dome sold its entire holdings of the common shares of the Company and Dome Canada Limited sold 50% of its holdings. On December 5, 1983, the remaining shares which were owned by Dome Canada Limited were purchased by Bell Canada Enterprises Inc. ("BCE"). BCE subsequently made a public offer to purchase on December 20, 1983 any and all other common shares of the Company. The combined total of all common shares of the Company acquired by BCE from Dome Canada Limited and by the public offer to purchase represented approximately 42% of the common shares outstanding at December 31, 1983.

The Company, with respect to its utility operations, sells gas to and/or incurs charges for gas transmission services for its affiliates Great Lakes and TQM and has contracts for the purchase of gas and the extraction of gas by-products from Dome. Reference is made to Note 1 regarding certain amendments to the Company's gas sales contracts with Great Lakes.

The utility operations of the Company come under the scrutiny of various regulatory authorities which establish, among other things, the terms and conditions with respect to the purchase, transportation and sale of gas under which the Company deals with outside parties, Great Lakes, TQM and Dome.

Dome also renders management services in connection with production of oil and gas and capital expenditures, the consideration for which is not material. During 1983, the Company acquired from Dome a 50% interest in a new extraction plant located at Empress, Alberta. This investment is included in Investments — Natural resources. Certain other transactions with Dome are described in Note 3.

Reference should also be made to Note 5 regarding certain loan transactions between the Company and its employees for the purchase of common shares of the Company.

9. Segmented Information

With the exception of the direct ownership of the natural gas transmission system extending from Alberta to Quebec, the Company's other major investments are principally through joint venture operations which are accounted for by the equity method. For information regarding these investments and their geographic location, reference is made to Notes 2 and 3.

10. Change in Accounting Policy for Foreign Currency Translation

The Company changed its accounting policy with respect to foreign currency translation prospectively from January 1, 1983 to conform with the recommendations of the Canadian Institute of Chartered Accountants. This change affects the method of translating financial statements of foreign operations and of recognizing unrealized foreign exchange gains and losses related thereto. Previously, the Company followed the temporal method to translate all of its foreign operations.

The prospective application of this change in accounting policy results in an increase in shareholders' equity due to cumulative translation adjustments totalling $21.8 million. The majority of this increase is represented by an increase in Investments in the statement of Consolidated Financial Position of $20.6 million. The impact of the change on net income for the year ended December 31, 1983 was not material.

11. Subsequent Event

On February 8, 1984, the shareholders of the Company approved a two-for-one share split of the Company's common shares. Each common shareholder of record on February 17, 1984 will automatically receive one new common share for each common share held. The number of common shares outstanding as at December 31, 1983 and 1982, after giving effect to this share split, would be 90,919,800 and 89,579,702 common shares, respectively.

PEAT MARWICK

Auditors' Report to the Shareholders

We have examined the statement of consolidated financial position of TransCanada PipeLines Limited as at December 31, 1983 and the consolidated statements of income, contributed surplus, retained earnings and source of funds for capital expenditures for the year then ended. 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 December 31, 1983 and the results of its operations and the source of funds for capital expenditures for the year then ended in accordance with generally accepted accounting principles which, except for the change in accounting for foreign currency translation described in Note 10, with which we concur, have been applied on a basis consistent with that of the preceding year.

Peat, Marwick, Mitchell & Co.

Toronto, Canada
February 8, 1984

Chartered Accountants

Eleven-Year Summary

Years ended December 31

(millions of dollars except where indicated)	1983	1982
Income		
Revenues		
Gas sales—domestic	$2,790.9	$2,382.7
—export	568.4	981.1
Gas transportation and other	111.4	103.1
	3,470.7	3,466.9
Costs and Expenses		
Cost of gas sold	2,486.9	2,425.4
Transmission, operating and general	517.2	552.0
	3,004.1	2,977.4
	466.6	489.5
Income from Investments		
Pipelines	84.6	52.9
Natural resources	21.7	30.1
	106.3	83.0
Other Income (net)	31.8	61.2
Financial Charges (net)	291.1	368.3
Income before income taxes	313.6	265.4
Income Taxes — Current and Deferred	85.5	66.5
Net Income for the Year before Extraordinary Gain	228.1	198.9
Gain on sale of subsidiary	—	—
Net Income for the Year	228.1	198.9
Less provision for dividends on preferred shares	36.3	37.8
Net Income Applicable to Common Shares	$ 191.8	$ 161.1
Net Income per Average Common Share		
Basic	$ 2.13	$ 1.81
Fully diluted	$ 2.11	$ 1.80
Dividends		
Dividends declared, per common share	$ .75	$ .595
Dividend payout ratio, common shares	% 35.13	% 32.87
Funds Generated		
Funds generated by operations	$ 312.0	$ 244.3
—per average common share	$ 3.47	$ 2.74
Funds generated by equity investments	$ 82.3	$ 82.0
—per average common share	$ .92	$ .92
Financial Position		
Plant, property and equipment—gross	$3,335.9	$3,266.8
—net	$2,628.3	$2,650.8
Long-term debt	$2,218.0	$2,152.9
Shareholders' equity—total	$1,425.0	$1,262.7
—common	$1,080.9	$ 917.5
—per common share at year end	$ 11.89	$ 10.24
Statistics		
Kilometres of pipeline—including loopline	10 626	10 631
Compressor power—kilowatts	1 020 500	1 020 500
Gas delivered for sales and transportation (millions of cubic metres)		
—annual	28 576	32 497
—maximum day	121	125
Number of regular employees, December 31	1,953	1,798
Common shares outstanding—year end	90,919,800	89,579,702
—average	89,880,160	89,075,264
Number of shareholders, December 31	22,415	22,378

1981	1980	1979	1978	1977	1976	1975	1974	1973
$2,082.2	$1,819.1	$1,634.1	$1,537.7	$1,254.2	$1,044.5	$ 686.8	$ 449.3	$ 341.7
1,261.5	1,268.0	921.0	633.9	597.4	438.4	214.4	111.9	88.7
61.2	36.0	25.9	21.6	18.7	16.2	19.2	6.7	6.4
3,404.9	3,123.1	2,581.0	2,193.2	1,870.3	1,499.1	920.4	567.9	436.8
2,502.7	2,446.1	1,990.5	1,703.5	1,447.7	1,108.6	601.0	316.7	227.3
485.1	390.9	338.3	300.9	279.8	255.6	191.5	147.3	130.1
2,987.8	2,837.0	2,328.8	2,004.4	1,727.5	1,364.2	792.5	464.0	357.4
417.1	286.1	252.2	188.8	142.8	134.9	127.9	103.9	79.4
28.4	9.9	10.4	8.0	9.4	8.3	6.6	6.1	6.0
20.8	6.1	.3	—	—	—	—	—	—
49.2	16.0	10.7	8.0	9.4	8.3	6.6	6.1	6.0
20.0	5.8	2.9	2.7	6.5	6.6	2.2	5.0	12.1
229.7	123.2	90.0	74.9	72.5	70.2	70.4	69.4	58.0
256.6	184.7	175.8	124.6	86.2	79.6	66.3	45.6	39.5
102.5	82.3	81.8	29.5	—	—	—	—	—
154.1	102.4	94.0	95.1	86.2	79.6	66.3	45.6	39.5
—	—	—	—	—	—	—	—	12.5
154.1	102.4	94.0	95.1	86.2	79.6	66.3	45.6	52.0
28.5	9.0	6.8	7.2	7.9	10.4	13.9	12.1	11.5
$ 125.6	$ 93.4	$ 87.2	$ 87.9	$ 78.3	$ 69.2	$ 52.4	$ 33.5	$ 40.5
$ 1.43	$ 1.09	$ 1.08	$ 1.10	$ 1.00	$ .96	$ .83	$ .58	$ .50
$ 1.42	$ 1.09	$ 1.07	$ 1.09	$ .98	$ .90	$ .73	$ .52	$ .46
$ .58	$ .58	$ .58	$ .53	$ .485	$ .43	$ .345	$ .24	$ .17
% 40.70	% 53.21	% 53.70	% 48.29	% 48.26	% 44.66	% 41.82	% 41.31	% 33.00
$ 275.7	$ 241.1	$ 202.5	$ 152.6	$ 138.3	$ 135.4	$ 108.0	$ 70.0	$ 47.4
$ 3.13	$ 2.82	$ 2.51	$ 1.91	$ 1.77	$ 1.87	$ 1.70	$ 1.22	$ .85
$ 27.4	$ 12.5	$ .9	—	—	—	—	—	—
$ .31	$ .15	$ .01	—	—	—	—	—	—
$2,465.1	$1,929.2	$1,811.5	$1,766.9	$1,720.9	$1,637.8	$1,588.8	$1,555.5	$1,449.9
$1,920.3	$1,438.9	$1,366.9	$1,363.9	$1,362.6	$1,322.7	$1,315.5	$1,315.0	$1,240.8
$2,458.8	$1,706.8	$1,384.7	$ 917.0	$ 822.3	$ 809.7	$ 819.8	$ 820.1	$ 861.3
$1,164.1	$ 966.8	$ 694.8	$ 650.5	$ 605.6	$ 568.0	$ 535.8	$ 508.4	$ 440.2
$ 799.6	$ 718.1	$ 604.2	$ 555.7	$ 501.8	$ 446.4	$ 317.8	$ 276.9	$ 228.5
$ 9.01	$ 8.17	$ 7.44	$ 6.93	$ 6.35	$ 5.84	$ 4.96	$ 4.45	$ 4.10
9 783	9 429	9 345	9 326	9 335	9 206	9 138	9 138	8 637
912 900	795 100	795 100	795 100	795 100	795 100	793 800	797 000	790 900
33 448	31 798	33 852	32 808	33 153	31 953	31 176	31 059	29 903
117	113	110	108	108	106	97	100	96
1,671	1,574	1,510	1,471	1,417	1,407	1,368	1,330	1,262
38,699,806	87,937,954	81,186,488	80,222,088	78,975,226	76,496,318	64,011,018	62,155,580	55,718,514
38,118,828	85,525,524	80,738,046	79,862,722	78,057,236	72,235,220	63,493,620	57,375,402	55,562,130
23,907	26,187	26,058	28,655	27,341	25,454	24,244	24,302	24,984

*Note: The above **Eleven-Year Summary** reflects the following:*
(i) a restatement of common shares outstanding and per share data resulting from the two-for-one share split approved February 8, 1984.
(ii) a restatement of 1976 earnings, increasing net income by $2.9 million.
In addition, the basic and fully diluted earnings per share amounts for 1973 are before the extraordinary gain on sale of subsidiary.

Shareholders and others desiring additional information on TransCanada PipeLines may request a copy of the booklet "Operating and Statistical Information—1983" from Mr. Mitchell T. G. Graye, Vice-President, Finance and Treasurer, TransCanada PipeLines, P.O. Box 54, Commerce Court West, Toronto, Ontario, M5L 1C2.

Directors

John M. Beddome
President and Chief Operating Officer
Dome Petroleum Limited, Calgary
(resigned December 5, 1983)

James M. Cameron
Executive Vice-President, Corporate
TransCanada PipeLines Limited, Toronto

John H. C. Clarry, Q.C.
Messrs. McCarthy & McCarthy, Toronto

A. Jean de Grandpré, Q.C.
Chairman, President and Chief Executive Officer
Bell Canada Enterprises Inc., Montreal

John P. Gallagher
Consultant, Calgary

Russell E. Harrison
Chairman and Chief Executive Officer
Canadian Imperial Bank of Commerce, Toronto

Robert H. Jones
Chairman and Chief Executive Officer
The Investors Group, Winnipeg

James W. Kerr
Consultant and Director
TransCanada PipeLines Limited, Toronto

Radcliffe R. Latimer
President and Chief Executive Officer
TransCanada PipeLines Limited, Toronto

Gerald J. Maier
President and Chief Executive Officer
Bow Valley Industries Ltd., Calgary
(appointed December 7, 1983)

Gordon P. Osler
Chairman, TransCanada PipeLines Limited, Toronto; Chairman, Stanton Pipes Limited, Toronto (appointed Chairman, TransCanada PipeLines, December 7, 1983)

Herbert C. Pinder
President, Saskatoon Trading Company Limited, Saskatoon

Smiley Raborn, Jr.
Petroleum Consultant, Calgary

William E. Richards
Consultant, Calgary
(resigned December 5, 1983)

Frank A. Schultz
Independent Oil Operator, Dallas

Allan R. Taylor
President and Chief Operating Officer
The Royal Bank of Canada, Toronto
(appointed December 7, 1983)

George W. Woods
Vice-Chairman, TransCanada PipeLines Limited, Toronto

Principal Officers

Officers

Gordon P. Osler
Chairman
(since his election December 7, 1983)

Radcliffe R. Latimer
President and Chief Executive Officer

George W. Woods
Vice-Chairman

James M. Cameron
Executive Vice-President, Corporate

Donald M. Johnston
Corporate Secretary

Alberta Division

C. Kennedy Orr
Senior Vice-President, Alberta Division

Craig R. Frew
Vice-President, Operations

Barry G. Luft
Vice-President, Gas Supply

Corporate Division

John K. Archambault
Senior Vice-President, Corporate

James W. S. McOuat, Q.C.
Vice-President, Law

Finance Division

H. Neil Nichols
Senior Vice-President and Chief Financial Officer

Mitchell T. G. Graye
Vice-President, Finance and Treasurer

Derek E. Henwood
Vice-President

Brian F. Hill
Vice-President, Business Development

Raymond F. Sim
Vice-President, Corporate Taxation

Kenneth G. Whiteside
Vice-President, Corporate Planning and Control

Ray T. Smith
Corporate Controller

Oil and Gas Division

Gordon A. Leslie
Vice-President

Arthur A. Wilkins
Vice-President

Pipeline Division

Richard D. Walker
Senior Vice-President and Chief Operating Officer

George M. Hugh
Senior Vice-President, Marketing and Administration

George C. Britton
Vice-President, Project Development

Robert J. Reid
Vice-President, Engineering and Operations

Robert S. Smith
Vice-President and Controller

Corporate Information

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TCPL Resources U.S.A. Ltd.
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Cancarb Limited
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Amsterdam, The Netherlands
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TCPL Investments AG
Baarerstrasse 110/B
CH-6300, Zug, Switzerland
Telephone 011-42-31-22-01

Principal Officers

Wholly-Owned Operating Subsidiaries

TCPL Resources Ltd.

James M. Cameron
Chairman and Chief Executive Officer

Gordon A. Leslie
President and Chief Operating Officer

Arthur A. Wilkins
Vice-President

TCPL Resources U.S.A. Ltd.

David G. Hanson
Vice-President

Cancarb Limited

A. Russell Steele
President and Chief Executive Officer

Klaus E. Grodd
Vice-President

TCPL Nederland B.V.

TCPL Investments AG

Lionel H. Pilon
Managing Director

Subsidiaries (100% owned)

TransCan Holdings Ltd.
A holding company.

TCPL Resources Ltd.
A company carrying on the business of oil and gas exploration and production.

Cancarb Limited
A subsidiary of TCPL Resources Ltd. which produces thermal carbon black.

TCPL Resources U.S.A. Ltd.
A Delaware company involved in oil and gas exploration.

TransCanada PipeLine USA Ltd.
A Nevada company holding shares of TransCanada PipeLine Alaska Ltd., TransCanada Border PipeLine Ltd., TCPL Resources U.S.A. Ltd., TransCanada PipeLine Niagara Ltd., TCPL Geothermal Ltd. and TCPL Ventures Ltd.

TransCanada PipeLine Alaska Ltd.
A Nevada company participating in the Alaska Natural Gas Transportation System.

TransCanada Border PipeLine Ltd.
A Nevada company owning an interest in the Northern Border Pipeline.

TransCanada PipeLine Niagara Ltd.
A Delaware company participating in the Niagara Interstate Pipeline System project.

TCPL Nederland B.V.
A Netherlands company carrying on financial operations.

TCPL Investments AG
A Swiss company carrying on financial, marketing and other international operations outside North America.

Affiliates (50%-owned)

Great Lakes Gas Transmission Company
A Delaware company owning and operating a pipeline through the United States from Emerson, Manitoba to Sault Ste. Marie and Sarnia, Ontario.

Trans Québec & Maritimes Pipeline Inc.
A company owning and operating pipeline facilities in Quebec.

Sable Gas Systems Limited
A company formed to carry out feasibility studies and initial planning for a natural gas pipeline to move anticipated natural gas supplies to markets from the offshore Sable Island area, through Nova Scotia and New Brunswick, to the United States border.

Corporate Information

Common Shares

Transfer Agent and Registrar
Montreal Trust Company, Montreal, Toronto, Winnipeg, Regina, Calgary and Vancouver

Preferred Shares

$2.80 cumulative redeemable first preferred shares
$4.50 cumulative redeemable retractable first preferred shares, Series B
Cumulative redeemable retractable first preferred shares, Series D
Cumulative redeemable retractable first preferred shares, Series E
Cumulative redeemable retractable first preferred shares, Series F

Transfer Agents and Registrars
$2.80 National Trust Company, Limited, Montreal, Toronto, Winnipeg, Calgary and Vancouver
$4.50 series B, series D, series E and series F, Royal Trust Company, Montreal, Toronto, Winnipeg, Regina, Calgary and Vancouver

Stock Exchanges
Preferred and Common Shares listed on Toronto, Montreal, Vancouver, Alberta and Winnipeg

Bonds

Trustee
National Trust Company, Limited, Toronto

Registrar Canadian Series
9¼% and 8⅞ first mortgage pipe line bonds, National Trust Company, Limited, Montreal, Toronto, Winnipeg, Calgary and Vancouver

Registrar U.S. Series
5⅝%, 7⅛%, 16% and 16¾% first mortgage pipe line bonds, Morgan Guaranty Trust Company, of New York

Co-Registrars U.K. Series
16½% first mortgage pipe line bonds, National Trust Company, Limited and The Royal Bank of Scotland, Limited

Debentures

Trustee
Central Trust Company, Toronto

Registrar
10% series A sinking fund, 9¾% series B sinking fund, 9% series C sinking fund, 8⅞% series D sinking fund, 9% series E sinking fund, 11½% series F sinking fund, 9.60% series G sinking fund, 18% series H sinking fund, and 11.70% series I, debentures Central Trust Company, Montreal, Toronto, Winnipeg, Calgary and Vancouver

Subordinated Debentures

Trustee
Montreal Trust Company, Toronto

Registrar Canadian Series
5.85% subordinated debentures, Montreal Trust Company, Montreal, Toronto, Winnipeg, Calgary and Vancouver

Registrar U.S. Series
5.60% subordinated debentures, Citibank, N.A., New York

Inside back cover
Snow clearing along the pipeline system, North Bay area, Station 116.


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TransCanada PipeLines

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