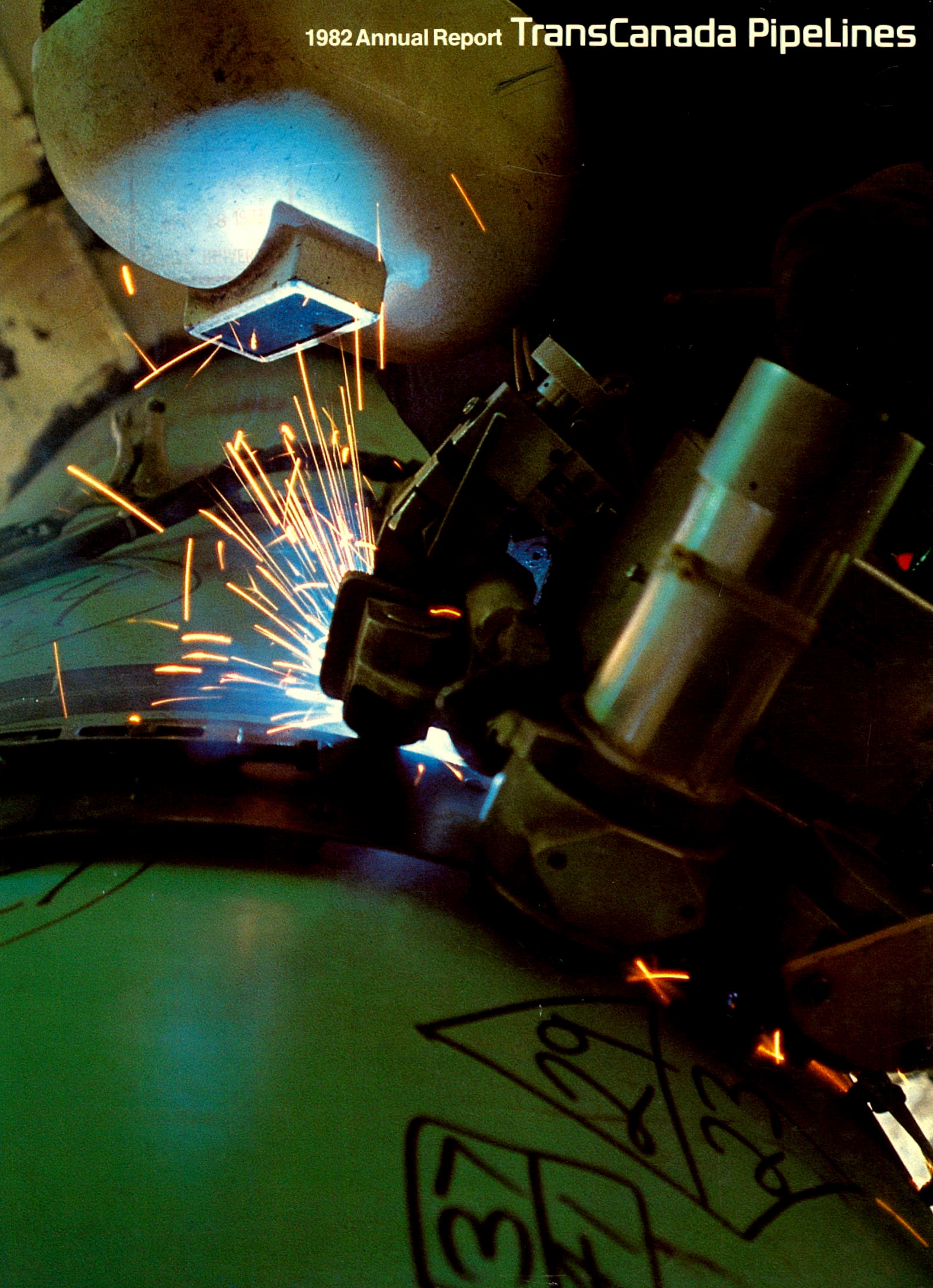
1982 Annual Report TransCanada PipeLines



TransCanada PipeLines is a Canadian company which owns and operates Canada's major west/east natural gas transmission system, from Alberta to Quebec. TransCanada also owns a 50% interest in Trans Québec & Maritimes Pipeline and a 44% interest in Foothills Pipe Lines (Sask.) pipeline, which it also operates. In addition to being a major purchaser of western natural gas for eastern Canadian markets, TransCanada is a major exporter of western Canadian natural gas to United States markets and owns a 50% interest in Great Lakes Gas Transmission Company and a 30% interest in Northern Border Pipeline. TransCanada also transports natural gas for other companies. The Company has extensive holdings of oil and gas lands in Canada and is participating in oil and gas exploration in Canada and the United States. The Company also holds an interest in oil and gas lands in Australia, Indonesia, Italy, the North Sea and other oil and gas areas. Assets now exceed $4.7 billion.

Cover
Welder using automatic welding machine on 914 mm diameter pipe, North Bay Shortcut near Renfrew, Ontario

Inside front cover
Pipeline construction, North Bay Shortcut near Mattawa, Ontario

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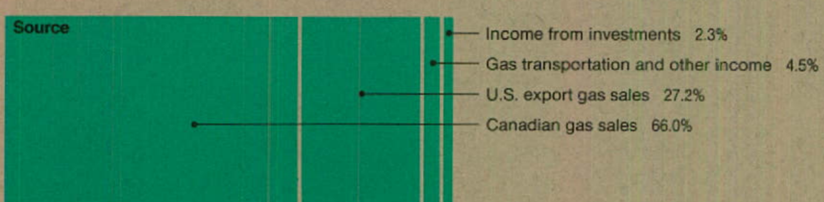
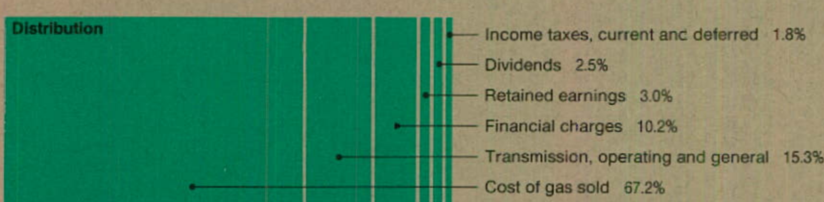
	1982	1981
Operations	**($000)**	($000)
Revenues	**3,466,915**	3,404,897
Net income applicable to common shares	**161,128**	125,573
Funds generated by operations	**244,427**	275,742
Funds generated by investments	**82,007**	27,370
Dividends declared		
Preferred shares	**37,855**	30,171
Common shares	**52,981**	51,170
Common Share Statistics		
Net income per common share	**$ 3.62**	$ 2.85
Funds generated by operations	**5.49**	6.26
Funds generated by investments	**1.84**	0.62
Dividends declared	**1.19**	1.16
Capital Expenditures	**($000)**	($000)
Plant, property and equipment	**772,493**	533,417
Investments		
Pipelines	**26,955**	239,226
Oil and gas	**22,861**	128,429
Payments on future gas supply	**10,715**	181,226

1982 Revenue dollars





1982 was a successful year for TransCanada PipeLines in which the Company set new records in construction, financing and profits. Unfortunately it was also a year in which the problems of the gas industry throughout North America became evident. The record warm winter of 1982-83 combined with the deep recession has put strains on the industry which cannot be glossed over. Fortunately the industry together with the governments concerned and the regulators are reacting very constructively. TransCanada believes that this spring marks the transition of our industry into the age of competitive markets and in the longer view we are sure this very painful transition is setting the stage for a period of growth.

1982 Financial Results

Net income applicable to common shares increased by 28% to $161,128,000, up from $125,573,000 in 1981.

Earnings per share in 1982 were $3.62, up from $2.85 in 1981.

Funds generated by operations and equity investments increased by 8% to $326,434,000 for the year, up from $303,112,000 in 1981.

The Company entered an agreement with respect to payments on future gas supply to the end of 1982 under which substantially all such payments were removed from the Company's balance sheet. In addition to strengthening the Company's balance sheet, future liability for such payments was effectively capped.

The Natural Gas Industry

The natural gas industry in North America faced a period of uncertainty throughout 1982. For the first time in many years the minimum volumes of gas contracted by many United States natural gas distributors have exceeded market requirements. In addition, the United States is in the process of moving from an artificially regulated natural gas market into a market in which free competition with other fuels will occur. This transitional state will last for some time and Canadian marketing of gas to the United States must adjust to the reality of a competitive market. We believe that the combination of current poor United States gas markets and this adjustment period, render it unlikely that the new gas exports approved by the NEB in January 1983 will start to move before the 1985-1986 heating season.

There is continuing uncertainty as to the duration of the current glut of oil on world markets and this uncertainty will prevail at least until the start of the 1983-84 winter season. These developments make a drastic reappraisal and restructuring of Canada's National Energy Program essential to reflect the change in competitive market conditions and to achieve reasonable stability in both domestic and export gas markets. Natural gas, as long as it remains tightly regulated, has no chance of being flexible enough to prosper in today's tough competition. Fortunately we believe this lesson has been learned and that the industry is already in the transition phase.

TransCanada also expects a sharp rebound this year in the Canadian and United States economies which, coupled with pricing flexibility, will improve the outlook for natural gas sales materially.

1982 Company Pipeline Operations

TransCanada's total domestic and export sales volumes of natural gas during the year were slightly lower than in 1981, but transportation of natural gas for others increased.

The Company's total sales and transportation volumes were down by 2.8% from 1981. Canadian sales volumes decreased from 23 369.4 million cubic metres in 1981 to 22 994.2 million cubic metres in 1982. This was partially offset by an increase of volumes of gas transported for other companies from 3 753 million cubic metres in 1981 to 4 852 million cubic metres in 1982. Overall Canadian sales and transportation volumes were down 1.2%. Export sales and transportation volumes decreased from 8 652 million cubic metres in 1981 to 8 006 million cubic metres in 1982, a decrease of 7.5%.

A major development in 1982 was the completion by the Pipeline division of a $772 million construction program, the largest in its history. The program, which will enable future expansion into new Canadian markets, brought natural gas service to new communities in eastern Ontario and provided a shorter transportation route for natural gas deliveries to Québec. The program included construction in Saskatchewan, Manitoba and Ontario and is estimated to have provided direct construction employment for over 4,000 persons. Over 94% of the materials used were of Canadian origin as a result of a "Buy Canadian" program first initiated by the Company in 1958.

Investments in Other Pipelines

TransCanada's investments in other pipelines increased their contribution to Company earnings in 1982.

The net income of Great Lakes Gas Transmission Company, in which the Company has a 50% interest, increased to (U.S.) $25,061,000 in 1982, up from (U.S.) $21,357,000 in 1981.

The first phase of the Northern Border pipeline, in which the Company has a 30% interest, commenced operations in October of 1982, was certified, and went on full tariff provisions on January 1, 1983.

The Company's affiliate, Trans Québec & Maritimes (TQM), in which the Company has a 50% interest, completed the construction of new pipeline facilities between Montreal and Trois-Rivières and made its first sales in 1982. Major construction has now been completed to Quebec City and gas should be delivered to this new market area sometime this summer.

The Company took over the operation of the Foothills Pipe Lines (Sask.) Ltd. pipeline facilities in southwestern Saskatchewan after completion of construction. TransCanada has a 44% interest in this company. These facilities connect the gas system in Alberta to the new Northern Border pipeline.

1982 Oil and Gas Operations

The Oil and Gas division increased the scope of its operations through the acquisition of 12½% of substantially all the assets of Hudson's Bay Oil & Gas Company Limited. This acquisition was chiefly responsible for an increase in production of oil, natural gas and natural gas liquids from an equivalent of 8,850 barrels of oil per day at the end of 1981 to a production of 24,520 barrels of oil per day at the end of 1982. As a result of the acquisition, the Company has become actively involved in several oil and gas exploration programs outside North America — particularly in Indonesia.

It should be no surprise that 1982 financial results of the Company's oil and gas diversification were very disappointing. Poor markets and high interest rates combined to cut severely into cash flow. As a result, exploration and development drilling fell sharply and proved reserves only increased a small amount through the year. These problems will continue during 1983 and it will not be until the upside of the energy cycle, which will be marked by growing markets and rising prices, that we will see the good results on our income statement that our large, high quality energy assets are capable of providing.


John M. Beddome, Chairman

Dome Secondary Offering

On March 16, 1983 Dome Petroleum Limited and Dome Canada Limited sold 11,000,000 common shares of TransCanada PipeLines to the public at a price of $25.625 per share by way of a secondary offering. Prior to the sale, Dome Petroleum and Dome Canada each held 23.01% of the outstanding common shares of the Company. Following this sale, Dome Petroleum Limited remained a holder of 9.61% of the Company's outstanding common shares and Dome Canada Limited remained a holder of 11.85% of the Company's common shares.

Topgas Holdings Limited

In October, 1982 the Company, with the co-operation of Alberta producers, the Alberta Petroleum Marketing Commission, and a consortium of banks structured a transaction that removed substantially all the Company's payments for future gas supply from its balance sheet. Under the agreement, nearly all of the Company's take or pay payments were transferred to the consortium of banks through Topgas Holdings Limited. As a result of this transaction, which involved a $2.3 billion financing, the Company received $981 million. Of this amount $663 million was used to repay bank indebtedness associated with the take or pay payments previously made by the Company. The remaining $318 million was used to assist in the financing of the 1982 utility capital expenditure program.

Outlook

The Company's capital expenditure in pipeline facilities will be sharply lower in 1983, with total investment estimated at $87 million. Investments of up to $13 million will be made by TransCanada in an extension of Trans Québec & Maritimes' pipeline facilities from Trois-Rivières to Quebec City. No additional investment will be required for the Northern Border pipeline.

The proposed extension of TQM pipeline facilities east of Quebec City has been postponed because of the probability of east coast offshore gas supplies and very high costs for the project.

In January 1983 the National Energy Board approved additional exports of natural gas. When United States approvals to market this gas are received, major investment by the Company in new pipeline facilities in Canada will be required to move the gas. We believe that construction in Canada will probably commence in 1985 and continue through 1987. In addition, several pipeline projects in the United States which are companion to the Canadian construction will provide additional investment opportunities in the United States.

Developments in 1982 have led the Company to reduce its forecast capital requirements for 1983 and 1984. In the next two years the Company's financial position will improve substantially so that we foresee no problems in financing the major expansion of pipeline facilities in the years 1985-1987. This expectation is, of course, dependent on the continuation of a regulatory and political environment in Canada that will give lenders confidence their money will be repaid and give shareholders confidence that they will be fairly treated.

As the natural gas industry moves into a future of tough competitive markets efficiency and cost savings continue to be very important. TransCanada recognizes that it is a vital part of our strategy to continue to design the minimum facilities needed to move additional gas. Aside from the cost of gas the overwhelming part of our cost of service for gas users is interest and depreciation on investment, and compressor fuel. We are aware that successful control of these factors is the best way to further our own interests and those of the industry.

TransCanada also anticipates that spending on oil and gas exploration and development will be at a more moderate level until markets for oil and gas improve.

Shareholders

In December, 1982, the annual rate of dividends was increased from $1.16 per share to $1.28 per share commencing with dividends paid January 31, 1983. The Board of Directors also approved a plan to allow common and preferred shareholders to reinvest their dividends in common shares of the Company and a plan that will allow common shareholders to receive stock dividends in place of cash dividends. Both plans commence operation April 30, 1983.

In March, 1983 the sale by Dome Petroleum and Dome Canada of over half of their holdings in TransCanada common shares added approximately 4,000 new common shareholders, bringing the total to over 26,000 common shareholders. It is a pleasure to welcome the new investors.

Employees

Once again we would like to express, on behalf of all shareholders, our thanks to our employees for their continued dedicated efforts during 1982, which contributed so much to a successful year in difficult times. The planning and carrying out by the Pipeline division of the large 1982 programs, the success of the Company's export applications, and the completion of the Take or Pay financing by the Alberta division were particularly noteworthy.

On behalf of the Board:

John Baddam

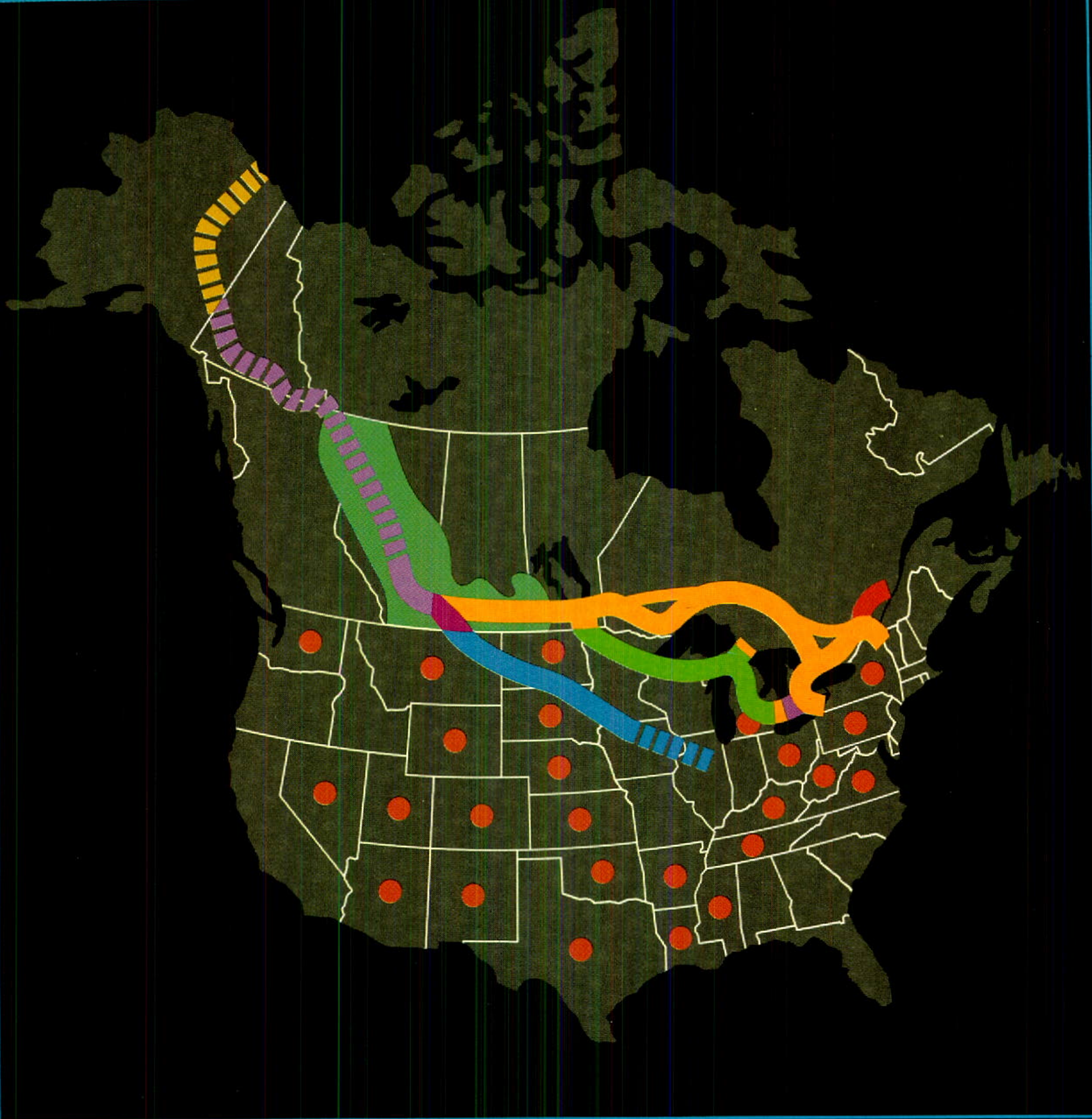
Chairman

Toronto, Canada, April 5, 1983

R Latimer

President and Chief Executive Officer

Radcliffe R. Latimer
President and Chief Executive Officer



Canadian Operations

- TransCanada PipeLines 100% Ownership
- Trans Québec & Maritimes Pipeline 50% Ownership
- Foothills Pipe Lines (Sask.) Ltd. 44% Ownership
- TCPL Resources Ltd. Oil and Gas Lands 12½% Ownership
- Connecting system

United States Operations

- Great Lakes Gas Transmission Company 50% Ownership
- TCPL Resources U.S.A. Ltd. Oil and Gas Lands 17 - 20% Ownership 25 States

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
- Phase 2 — Northern Border Segment 17% interest

Alberta Division

Company Gas Reserves and Alberta Permits

As at December 31, 1982, TransCanada PipeLines had approximately 1 414 billion cubic metres of contracted gas reserves in western Canada, of which approximately 536 billion cubic metres had then been produced, including production of 36 billion cubic metres for the twelve months ended October 31, 1982. More than 99% of the contracted reserves are located in Alberta, with the balance of reserves being in Saskatchewan.

The Gas Resources Preservation Act of Alberta states that no natural gas may be removed from Alberta without a permit from the Alberta Energy Resources Conservation Board (the "AERCB"). Under this legislation, the Company holds three permits, (one expiring October 31, 1989 and two expiring October 31, 1994) which in total allow the Company to remove up to 39.4 billion cubic metres of gas in any 12-month period ending October 31. As at December 31, 1982, these authorizations provided for a further removal of 369 billion cubic metres of gas.

The AERCB has recommended the total volume which may be removed from Alberta under the Company's major removal permit be increased by 302 billion cubic metres, and that the permit term be extended for five years to October 31, 1999. The increase will enable the Company to satisfy additional exports authorized by the National Energy Board as well as to continue to satisfy existing and future domestic requirements and previously authorized exports.

The AERCB has also recommended that the Company be granted a new permit for removal from Alberta of 44 billion cubic metres of natural gas over a 20 year period commencing April 1, 1986. The permit will enable the Company to supply its portion of the gas required by Dome Petroleum Limited for liquefaction and delivery to Japanese utility companies.

Both of the recommendations require approval by the Alberta Government.

Topgas Holdings Limited

Substantially all of the Company's gas purchase contracts have provisions requiring payments (take or pay payments) by the Company when it is unable to request specified minimum quantities of gas for delivery. As the contracted supply has exceeded the available market in recent years, it has been necessary to make such payments.

During 1982 the Company concluded arrangements with a consortium of Canadian and foreign banks and substantially all of its producers, to refinance its take or pay payments (the "Topgas Program"). Under this program, Topgas Holdings Limited ("Topgas"), an Alberta corporation controlled by the banking consortium, made advances to producers in an amount equal to that previously advanced to the producers by the Company. In addition, Topgas made advances to the producers in respect of deferred gas for the 1980/81 and 1981/82 contract years which the Company had been excused from making under a previous allocation program. Under the Topgas Program the producers refunded to the Company all take or pay payments previously made to them by the Company and have foregone further take or pay advances except at a substantially reduced level of contract obligation. As a result of implementation of the program on October 5, 1982, the Company's asset, "Payments on Future Gas Supply", was essentially all assumed by Topgas and 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 approximately $2.3 billion. This total amount is scheduled to be recovered over the maximum program term ending October 31, 1994.

The interest costs associated with the funds advanced by Topgas to the producers will be recovered in the Company's Alberta cost of service and remitted to Topgas by the Company.

Conversion from metric

TransCanada reports its pipeline 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	Mcf	35.3
millions of cubic metres	MMcf	35.3
billions of cubic metres	Bcf	35.3
kilometres	miles	0.62
millimetres	inches	0.04
gigajoules	MMBtu	0.95
kilowatts	H.P.	1.34
kilopascals	psi	0.15

Pipeline Division

1982 Construction

The Company's 1982 capital expenditure program was the largest ever undertaken in a single year. This program, designed to increase the throughput capacity and improve the operating efficiency and security of the system, resulted in an expenditure of $772 million.

One of the major projects in 1982 was a new pipeline, known as the "North Bay Shortcut", which was constructed to connect the Company's existing facilities at North Bay and at Morrisburg, Ontario. This 428 kilometre pipeline, 914 millimetres in diameter, which parallels the Ottawa River, provides a shorter route to serve natural gas markets in Montreal and east. Construction commenced in January, 1982 and was placed in service ahead of schedule in December, 1982.

The right-of-way was acquired through negotiation with approximately 600 landowners without expropriation and all the environmental concerns of these landowners and governmental authorities were satisfied. Final clean-up and restoration of the right-of-way will be completed in the summer of 1983.

The fifth line in Saskatchewan and Manitoba, the largest diameter pipeline in Canada for the transmission of natural gas, was extended with the installation of a further 187 kilometres of 1 219 millimetre diameter pipe. Construction commenced in June, 1982 and was placed in service by sections during October and November, 1982. Final clean-up and restoration of the right-of-way will be completed in the summer of 1983.

In addition, all other major pipeline construction commenced in 1981 was completed and placed in service during the year 1982. This construction consisted of 207 kilometres of 1 067 millimetre diameter third pipeline in Manitoba, east of Winnipeg and in northern Ontario, a further extension of the third pipeline between Toronto and Montreal with the installation of 13 kilometres of 914 millimetre diameter pipe and in Québec the completion of the second line on the Saint Mathieu extension with the installation of a further 13 kilometres of 508 millimetre diameter pipe.

The compression component of the facilities expansion program in 1982 consisted of the completion and placing in service of six large fuel-efficient compressor units at one new compressor station and five existing compressor stations in northern Ontario. This program resulted in a total compression power increase of 107 600 kilowatts. The new units, combined with the previously-installed fuel-efficient units, have resulted in a significantly lower ratio of fuel consumption to throughput.

The continuing program of ensuring that the pipeline is adequately protected against corrosion included the inspection of 3 000 kilometres of pipe and completion of the necessary remedial work. The Company's high standards of gas conservation and operating efficiency were maintained by regular performance testing of compression equipment and by plant modifications.

1983 Construction

In addition to the final clean-up and restoration of the right-of-way of the North Bay Shortcut and the Saskatchewan and Manitoba loop line placed in service in 1982, the Company will also continue the ongoing program of modifications and upgrading of existing plant and pipeline facilities to maintain efficient and safe operation of the system at an estimated cost of $87 million.

Buying Canadian

In 1956, when TransCanada's initial system was about to commence, many types of required materials such as high pressure pipe, valves and fittings, were not available from Canadian sources and had to be imported.

In 1958 the Company established a policy to encourage the development of Canadian-manufactured products consistent with price and quality. This policy to achieve Canadian-produced products has enabled the Company to increase its Canadian content from approximately 25% in 1956 to a current 90%. This impact of our "Buy Canadian" policy has benefitted virtually every province in Canada, and has created hundreds of thousands of man-years of work for Canadians from coast to coast in the past 27 years.

The large-diameter high-pressure pipe in service constitutes approximately 75% of our procurement dollars and has been totally produced by Canadian pipe mills since 1958, when the first Canadian mill was placed in service. In 1982 the large diameter pipes and internal and external coatings, amounting in value to $210 million, were completely produced in Canadian pipe mills located in Alberta, Ontario and Saskatchewan.

TransCanada also encourages local procurement policies with communities in close proximity to the transmission system. This practice has proved mutually beneficial to suppliers and the Company.

Building up foam breakers to support the pipeline and prevent soil erosion on steep inclines

Marketing

The depressed economy in both Canada and the United States, the warmer than normal weather and the continued effects of energy conservation, combined to depress natural gas sales by the Company in both Canada and the United States in 1982. During the year the Company's total sales and transportation volumes decreased by 2.8% from 1981.

In Canada, in 1982, Canadian sales volumes were down 375 million cubic metres, but this was partially offset by an increase in Canadian transportation volumes of 70 million cubic metres. Overall, Canadian sales and transportation volumes were down 1.2%.

Export sales and transportation volumes decreased by 7.5% in 1982 from 1981. The decline in export sales resulted chiefly from a depressed United States economy, and from an increased short-term supply of natural gas in the United States. Export sales to the U.S. decreased by 1 675 million cubic metres from 1981, while transportation of gas for other exporters to the U.S. increased by 1 029 million cubic metres.

Domestic Sales to New Communities

TransCanada continued its efforts to develop additional markets for domestic and export sales. The completion in December, 1982 of a new transmission line from North Bay to Morrisburg in Ontario (the "North Bay Shortcut"), along with the construction by TQM of pipeline facilities from Boisbriand, north of Montreal to Trois-Rivières, has permitted natural gas sales for the first time to serve several additional communities in the Ottawa Valley and Québec.

Natural Gas Marketing Support Programs

TransCanada also worked closely with its distribution customers in Québec and with the federal Ministry of Energy, Mines and Resources (EM&R) to expedite implementation of a Natural Gas Marketing Support Program to promote the development of new markets for natural gas. In November of 1982 TransCanada's customers, Gaz Métropolitain, inc. and Gaz Inter-Cité Quebec (GICQ), distributors of natural gas in Québec, concluded agreements with EM&R providing for financial assistance. The subsidy program enabled new markets in the Boisbriand, Joliette, Trois-Rivières and Louiseville areas to come on stream during November and December, 1982, increasing TransCanada's daily contracted quantity by a total 2 074 thousand cubic metres per day.

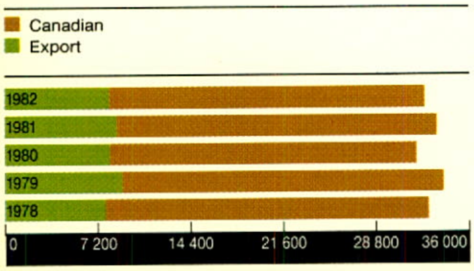
During 1982 the Federal Government, under the Canadian Oil Substitution Program, issued grants for 59,330 conversions from oil to natural gas in the Company's gas service areas in Saskatchewan, Manitoba, Ontario and Québec. This will result in additional annual natural gas sales of approximately 210 million cubic metres and a displacement of approximately 200 thousand cubic metres of crude oil annually.

In 1982 our Canadian distributors, under the Federal Government Distribution System Expansion Program, added 27,490 customers by expanding their distribution networks. This will result in additional annual sales of natural gas of approximately 370 million cubic metres and a displacement of approximately 360 thousand cubic metres of crude oil annually.

1983 Additions

The extension of pipeline transmission facilities by TQM from Trois-Rivières to Quebec City, will permit natural gas service to commence in additional Québec communities for the first time. Laterals, to be constructed from the TQM system by GICQ in 1983, will provide natural gas service to Shawinigan, Grand-Mère and Bécancour and communities in the eastern townships.

Gas delivered for sales and transportation
Millions of cubic metres



Bending 1 219 mm pipe near Brandon, Manitoba to conform to contours of the pipeline ditch


CATERPILLA

Annual Gas Sales and Transportation Volumes

(in thousands of cubic metres)

Sales	1982	1981	1980	1979	1978
Saskatchewan Power Corporation	**57 310**	35 560	166 706	444 824	514 967
Plains-Western Gas (Manitoba) Ltd.	**296 967**	238 243	251 994	260 014	246 252
Inter-City Gas Corporation	**239 825**	216 440	238 057	250 637	236 324
Greater Winnipeg Gas Company	**1 362 133**	1 332 688	1 413 725	1 508 782	1 470 968
Northern & Central Gas Corporation Ltd. Ontario Division	**3 029 432**	3 449 209	3 483 152	3 546 983	3 465 416
The Consumers' Gas Company Ltd.	**8 170 197**	8 247 993	8 025 751	8 151 365	8 821 619
Union Gas Limited	**7 276 464**	7 141 439	6 407 173	6 840 115	6 826 009
Kingston Public Utilities Commission	**76 101**	84 933	79 813	74 731	69 544
Gaz Métropolitain, inc.	**2 485 354**	2 622 884	2 330 752	2 220 273	2 127 757
Trans Québec & Maritimes Pipeline Inc.	**379**	—	—	—	—
Total Canadian	**22 994 162**	23 369 389	22 397 123	23 297 724	23 778 856
Michigan Wisconsin Pipe Line Company	**200 003**	372 997	383 020	516 986	516 983
Midwestern Gas Transmission Company	**1 583 241**	2 868 160	3 713 995	4 273 792	3 297 931
Great Lakes Gas Transmission Company	**2 437 712**	2 616 861	2 663 417	3 206 072	3 033 437
Inter-City Gas Limited	**143 755**	157 585	169 441	188 078	190 634
Niagara Gas Transmission Limited	**157 288**	179 699	183 003	186 033	176 516
Vermont Gas Systems, Inc.	**128 009**	130 001	119 566	128 740	119 644
Additional Exports	**—**	—	—	60 174	—
Total U.S. Export	**4 650 008**	6 325 303	7 232 442	8 559 875	7 335 145
Total Sales	**27 644 170**	29 694 692	29 629 565	31 857 599	31 114 001
Transportation	**4 852 478**	3 753 127	2 167 927	1 994 348	1 693 994

Regulatory Proceedings

1982 Tolls Decision

The Company's utility tolls were adjusted by the National Energy Board (NEB) effective August 1, 1982. The Board found that a rate of return on rate base of 13.88% per annum was just and reasonable. The authorized rate of return on rate base prior to that decision was 12.63%. The Federal Government, under the Energy Administration Act, prescribed prices for Canadian sales for the month of August, with transportation tolls lower than those authorized by the NEB. Subsequently, the Federal Government prescribed prices effective September 1 for Canadian sales which reflected the transportation tolls approved by the Board. As a result of the one month delay in implementing the higher transportation tolls, the Company's gross revenue was approximately $8 million less than would otherwise have been the case.

From August 1, 1978 to July 31, 1982 the NEB directed the Company to follow the deferral method of tax allocation accounting, whereby deferred income taxes and income taxes payable were recovered in its cost of service. In the 1982 toll decision, the NEB directed the Company to revert to the flowthrough method of income tax accounting which applied prior to August 1, 1978, whereby only income taxes payable are recovered in its cost of service. The decision will have no effect on the current earnings of the Company, but will have a significant effect on cash flow.

1983 Tolls Application

The Company, in January, 1983, applied for new tolls to be effective August 1, 1983. The principal reasons for new tolls are to recover projected increased costs including costs associated with the large 1982 capital additions to the pipeline system and an increase in the rate of return on rate base from 13.88% to 14.46%. However, to approach the objective of the Federal Government's price restraint program announced in June 1982 the Company has proposed to the extent necessary that the NEB freeze the recovery of return and associated income taxes with respect to the North Bay Shortcut at the level included in current tolls. The additional costs which would otherwise be included in the August tolls are proposed to be deferred and to be amortized over a three-year period commencing August 1, 1984.

Export Hearings

A major focus for Marketing in 1982 was the National Energy Board (NEB) hearing of 14 applications to export Canadian natural gas. The NEB hearings commenced in March, 1982 and concluded in November, 1982. A decision was rendered by the NEB on January 27, 1983.

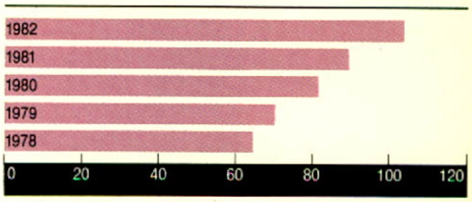
The NEB authorized, in total, new or extended exports of 322.5 billion cubic metres by all applicants. The NEB approved, with respect to TransCanada, a total of 81 billion cubic metres, as follows:

Customer	Daily Volumes	Term Volumes
	Thousand cubic metres	Billion cubic metres
(a) At Niagara Falls		
Boundary Gas Inc.	2 620.3	9 350.2
Tennessee Gas Pipeline Co.	4 249.2	15 163.2
Transcontinental Gas Pipe Line Corp.	4 249.2	16 329.6
Texas Eastern Transmission Corp.	1 416.4	5 443.2
(b) At Emerson, Manitoba		
Michigan Wisconsin Pipe Line Company	2 832.8	10 886.4
Natural Gas Pipe Line Company of America	2 832.8	10 886.4
Midwestern Gas Transmission Co.	6 317.1	12 960.8

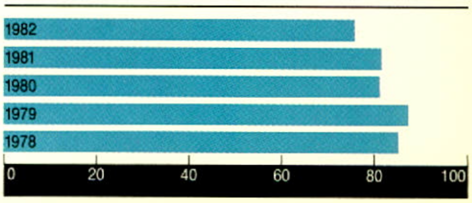
In addition to the approved TransCanada exports, the NEB approved export projects for others, which will add transportation volumes of 15 183.5 thousand cubic metres per day at Emerson and 12 054.9 thousand cubic metres per day at Niagara.

Subject to approval by the appropriate governmental and regulatory authorities, the Company will design and construct the additional facilities required to transport these new sales and transportation volumes. In the next five years the cost of the facilities required on the Company's pipeline system is estimated to be in the order of $3 billion, with major construction likely to start in 1985.

Average price Canadian sales
Dollars per thousand cubic metres



Average daily sales
Millions of cubic metres



Economic Effect of Natural Gas Exports

The new exports will require expansion of producer facilities and existing pipeline systems. Incremental capital expenditures by the Alberta petroleum industry and the pipeline companies will approximate $6 billion in 1983 dollars. On the TCPL system alone, expansion would be about $3 billion. There will be approximately 7,000 man-years of construction jobs and direct operating jobs created from Alberta to Ontario.

Large quantities of Canadian steel and other manufactured goods will be required. Expenditures on pipeline and petroleum industry facilities expansion will have a ripple effect throughout the economy. The direct and indirect income impact approximates $28 billion dollars and will generate about 2,200 permanent long-term jobs.

Incremental operating expenditures (excluding taxes, pipeline fuel, depreciation and royalties) represent another $2 billion.

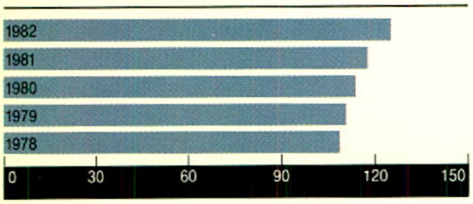
Net cash flow to the petroleum industry will equal $3 billion. This will help to alleviate the present situation in Alberta where many gas producers, both large and small, are faced with a chronic cash flow problem.

Revenues derived from the new export sales will improve Canada's balance of payments and help strengthen the dollar. A stronger Canadian dollar would allow Canada greater flexibility in its interest rate policy and assist in controlling inflation. Natural gas exports in 1981 provided the third largest source of foreign exchange earnings next to the motor vehicle and forest products industries.

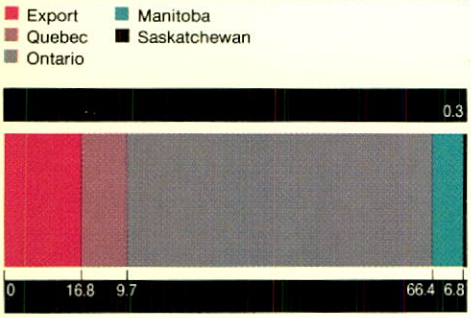
The Alberta, Federal and other provincial governments will receive substantial amounts of new revenue through taxation of the increased revenues generated by exports. Total direct tax revenue generated from TransCanada's new exports will be about $12 billion.

The measurable net benefit to Canada, resulting from the new exports, is estimated to approximate $6 billion.

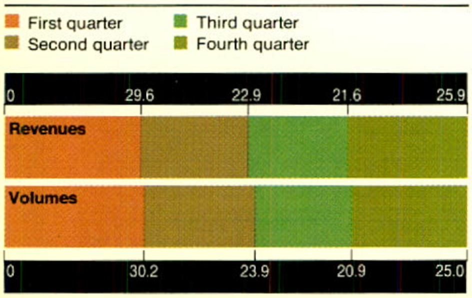
Maximum day gas delivered for sales and transportation
Millions of cubic metres



Where the gas was sold in 1982
Percentage of volume sales



Distribution of sales revenues and volumes
Percentage by calendar quarter



Pipe fabrication Welland, Ontario


MFD
DORTMUND

Pipeline Investments/Canada

Trans Québec & Maritimes Pipeline

TransCanada PipeLines owns a 50% interest in Trans Québec & Maritimes Pipeline Inc. (TQM), the company which is presently constructing a pipeline from TransCanada's facilities near Montreal to market areas in Québec.

Construction of the TQM pipeline began in 1981. In February, 1982 the first deliveries were made from the new pipeline at Boisbriand, north of Montreal; deliveries were made at Trois-Rivières in November, 1982, as scheduled. The section from Trois-Rivières to Quebec City is now under construction, with deliveries at Quebec City scheduled for August, 1983.

The National Energy Program Update, unveiled in May, 1982, has had a significant impact on the TQM project. While it had been planned that TQM would build a substantial number of laterals in the province of Québec, the Federal Government has now required that the local distributors, rather than TQM, construct and operate these laterals. The first step toward the implementation of this policy was taken in October, 1982, when the Federal Government signed with Gaz Inter-Cité Québec an agreement in principle providing a grant of approximately $500 million for the construction of laterals and sub-laterals in the eastern townships and the Lac-Saint-Jean region.

TQM also holds a certificate issued by the National Energy Board for pipeline facilities from Quebec City through the provinces of New Brunswick and Nova Scotia.

With respect to the Maritimes portion of the project, the National Energy Program Update discloses that it is now opportune to wait for an assessment of Sable Island production possibilities prior to committing to construction. Therefore, final pipeline design and construction activities beyond Quebec City has been deferred.

When the TQM system is completed to Quebec City, it will consist of 335 kilometres of pipeline, including 293 kilometres of mainline and 42 kilometres of laterals. In accordance with commitments made to the National Energy Board, the Canadian content of the system in the Quebec City section is 92%.

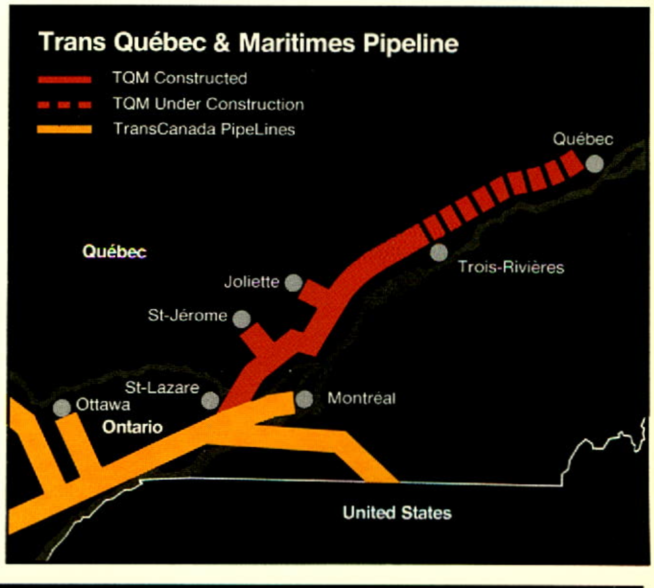
The capital cost for the construction of the system to Quebec City is estimated at $500 million.

Foothills Pipe Lines (Sask.) Ltd.

The Company owns a 44% interest in Foothills Pipe Lines (Sask.) Ltd., which has constructed a 257 kilometre pipeline across southwestern Saskatchewan to connect with the Northern Border pipeline at Monchy. The Company commenced operating this pipeline when construction was completed and deliveries commenced in September, 1982.

Up to and including 1982, total cash expenditures on this line were approximately $293 million of which the Company made cash expenditures of approximately $28 million. The Company does not anticipate further capital expenditures in 1983.

Drilling and blasting pipeline trench through rock on Trans Québec & Maritimes construction near Quebec City



TCPL Resources Ltd.

In 1982 TCPL Resources Ltd. (Resources) experienced significant changes in its operations as a result of the acquisition in March, 1982 of a 12½% undivided interest in substantially all the Canadian and foreign assets of Hudson's Bay Oil and Gas Company Limited (HBOG). With this purchase at approximately $560 million, Resources' investment in oil and gas properties stood at $1.2 billion on December 31, 1982.

Sales revenues in 1982 were $178,539,000, almost five times Resources' 1981 revenues of $36,766,000. Conventional crude oil production amounted to 4.7 million barrels, 3.4 times the 1981 volume of 1.4 million barrels. In addition, synthetic crude oil production from the Syncrude Project amounted to 0.2 million barrels. Natural gas production in 1982 was 669 360 000 cubic metres, approximately 2.3 times the 1981 volume of 294 230 000 cubic metres. Much of the increased production resulted from the HBOG acquisition.

Prior to acquiring the HBOG assets, Resources' Canadian interests in oil and gas properties were confined to western Canada. These interests are held in the MT Partnership, a partnership owned equally by Resources and Maligne Resources Limited (Maligne), a wholly-owned subsidiary of Dow Chemical Canada Inc. The western Canadian HBOG properties were also transferred to the MT Partnership. Dome Petroleum Limited (Dome) operates and manages the properties in the MT Partnership under a joint exploration agreement between Dome, Resources and Maligne. On March 1, 1983 Resources took over from Maligne as manager of the MT Partnership.

Resources' foreign oil and gas interests acquired from HBOG are located in Indonesia, Australia, Brazil, Egypt, Italy and the North Sea. The most significant of the foreign assets are located in Indonesia, namely in the Malacca Strait, Southeast Sumatra, Natuna and Madura concessions.

Resources participated in the drilling of 143 gross exploratory wells and 289 gross development wells in Canada and abroad during 1982. Of the 143 exploratory wells, 85 were productive and 58 were dry. Of the 289 development wells, 270 were productive and 19 were dry. In addition, 432 wells were drilled on Resources' property at no cost to Resources as a result of farmout agreements with other companies. Of these wells, 126 successful oil wells and 209 successful gas wells were completed. Resources' drilling activity in Canada in 1982 was down approximately 58% from 1981 levels, reflecting the general turndown in activity of the oil and gas industry. This significantly reduced exploration and development expenditures under the joint exploration agreement with Dome.

Of the 432 gross exploratory and development wells drilled, 323 were drilled in western Canada and 109 wells were drilled outside of North America on oil and gas interests acquired from HBOG.

Other oil and gas interests Resources acquired from HBOG are located in the Beaufort Sea, the Arctic Islands and offshore eastern Canada. At present, exploration agreements for these Canadian frontier regions are being negotiated with the Canadian Oil and Gas Lands Administration department, the federal group responsible for administering these regions.

As at December 31, 1982, Resources held an interest in 81.3 million gross acres, amounting to approximately 4.5 million net acres. In addition, royalty interests were held in approximately 2.2 million acres.

Resources' remaining oil and natural gas reserves at December 31, 1982, were 86.2 million barrels of oil and natural gas liquids and 25 781 million cubic metres of natural gas, respectively. The 86.2 million barrels of oil and natural gas liquids is after having produced 4.7 million barrels of oil and natural gas liquids during 1982. The 25 781 million cubic metres of natural gas is after having produced 669 million cubic metres during 1982.

The National Energy Program, announced by the Government of Canada in October, 1980, proposed an incentives plan to encourage Canadian participation in the oil and gas industry. Enterprises which are Canadian-controlled and at least 50% Canadian-owned, will qualify for incentive payments which will, in essence, rebate a specified percentage of approved oil and gas exploration and development costs. Resources qualified for the maximum incentive grants in 1982. These grants equalled 35% of its exploration costs and 20% of its development costs for provincial lands and 80% of its exploration costs and 20% of its development costs for lands under federal jurisdiction.

Drilling platform in Malacca Straits, Indonesia

Oil Sands

HBOG held a 5% interest in the Syncrude project where synthetic crude oil is mined from the Athabasca oil sands. Resources acquired a 12½% share of HBOG's interest in March, 1982. During the last 10 months of 1982, Resources received gross sales revenues of approximately $8 million from its interest in the Syncrude project.

Mining Properties

Resources' share of HBOG assets also included a 12½% interest in certain mining properties, including Cyprus Anvil Mining Corporation ("Cyprus Anvil"), which owns an open pit lead-zinc-silver mine and ore concentrator at Faro in the Yukon. In the spring of 1982 the mine suspended operations. The ultimate realization of Resources' investment in Cyprus Anvil is dependent upon Cyprus Anvil obtaining satisfactory financing, and upon improved mineral market conditions. At December 31, 1982, mineable reserves at the Faro Mine, as reported by Dome, totalled approximately 31 million short tons, grading 2.9% lead, 4.3% zinc and 1.0 ounce of silver per ton.

Cirque, a major lead-zinc-silver deposit containing over 44 million short tons of mineable ore, has been identified in the Akie district of northeastern British Columbia. The Cirque deposit is directly owned 50% by Cyprus Anvil, 43¾% by Dome, and 6¼% by Resources. Through their share ownership of Cyprus Anvil's parent company Dome indirectly owns a further 43¾% and Resources indirectly owns a further 6¼% of Cirque.

Resources acquired 12½% of HBOG's one third interest in Les Mines Selbaie, which is a copper-gold-silver mine operating in northwestern Québec. Developed ore reserves at Les Mines Selbaie as at December 31, 1982, totalled 4.2 million short tons, grading 3.5% copper, 0.17% zinc, 0.9 ounce of silver per ton and 0.03 ounce of gold per ton. The mine continued to operate on a marginal basis through 1982.

At December 31, 1982, Resources' total investment in all mining properties amounted to $47,087,000.

Extraction Facilities

Resources has agreed, subject to the fulfillment of certain conditions, to acquire from Dome, Dome's right to a 50% participation with Nova, an Alberta Corporation in new extraction facilities under construction at Empress, Alberta. These facilities will be operated by Dome. The plant will extract ethane, liquid petroleum gases and natural gas liquids from up to 56 million cubic metres per day of natural gas. It is contemplated that Resources will be a 50% investor on a cost-of-service basis in the new facilities, the total cost of which is currently estimated at approximately $200 million. It is expected that this plant will go into service in November of 1983.

TCPL Resources Ltd.

Land Holdings Summary at December 31, 1982
(Thousands of Acres)

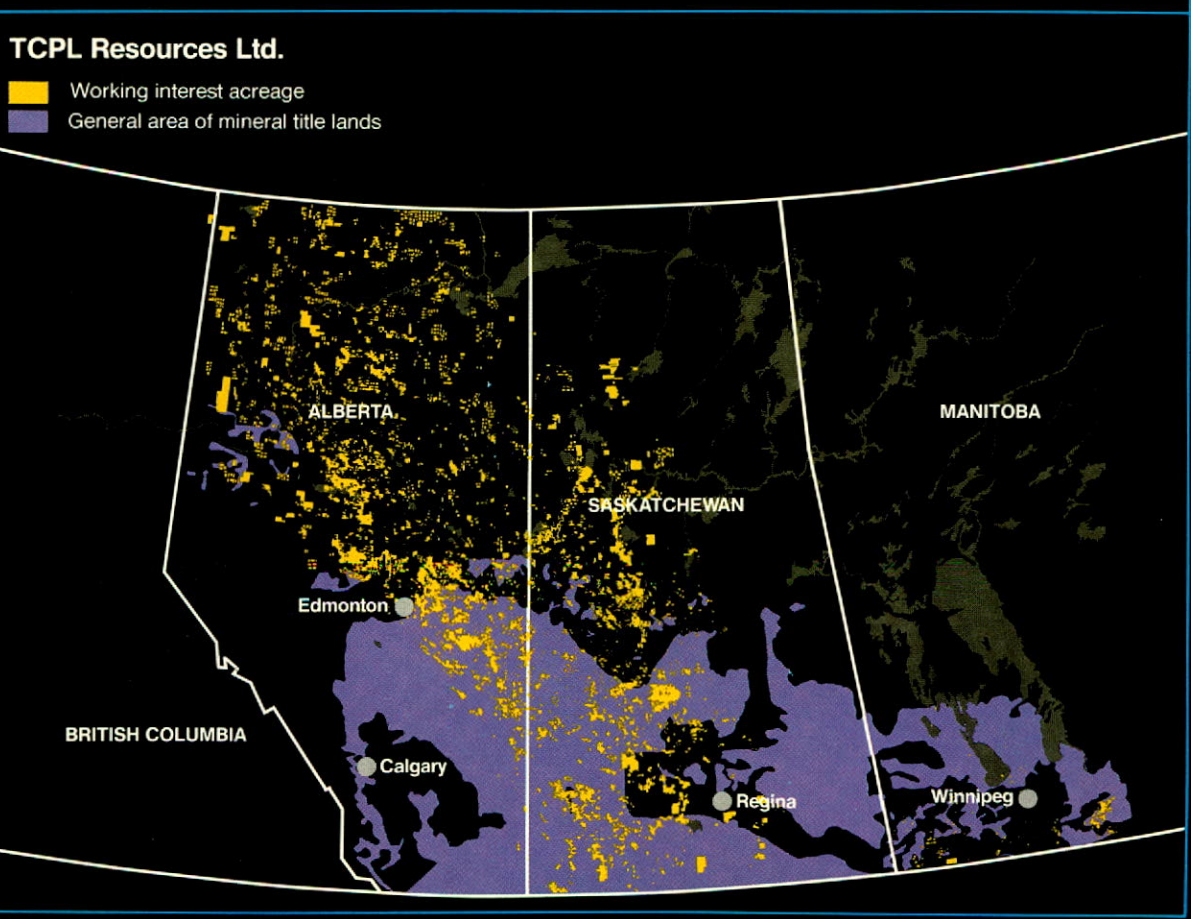
	Working Interest Gross	Net	Royalty Interest
Canada			
Western Canada			
Alberta	19,191	1,611	633
British Columbia	3,730	347	160
Saskatchewan	3,186	310	147
Manitoba/Ontario	1,190	124	0
Northwest Territories	2,992	223	788
Total Western Canada	30,289	2,615	1,728
Canadian East Coast	13,480	240	0
Arctic Islands	1,220	25	478
Beaufort Sea	1,736	82	0
Total Canada	46,725	2,962	2,206
Foreign			
Indonesia (1)	14,277	517	0
Australia	17,676	1,032	0
Brazil	760	32	0
Egypt	890	19	0
Italy	176	21	0
Netherlands	568	10	0
Norway	66	1	0
U.K.	138	2	0
U.S.A.	6	0	0
Total Foreign	34,557	1,634	0
Grand Total	81,282	4,596	2,206

(1) Land Interests held through share ownership.

Reserves Summary

	Dec.31,'81	Dec.31,'82
Crude Oil and Natural Gas Liquids (MMBBLS)	36.5	79.9
Synthetic Crude (MMBBLS)	–	6.3
Natural Gas ($10^6 m^3$)	13 371	25 781


Existing Landholdings
ARCTIC ISLANDS
BEAUFORT SEA
CANADA
WESTERN CANADA
CANADIAN EAST COAST
NORTH SEA
ITALY
U.S.A.
ATLANTIC OCEAN
EGYPT
PACIFIC OCEAN
INDONESIA
See detailed map inset left
PACIFIC OCEAN
BRAZIL
AUSTRALIA
NATUNA Block
Mayalsia
South China Sea
Singapore
ALACCA
trait Block
Kalimant
Sumatra
South East SUMATRA Block
Java


TCPL Resources Ltd.
Working interest acreage
General area of mineral title lands
ALBERTA
SASKATCHEWAN
MANITOBA
Edmonton
BRITISH COLUMBIA
Calgary
Regina
Winnipeg

Oil and Gas Division/United States Operations

TCPL Resources U.S.A. Ltd.
1982 was a disappointing year for TCPL Resources U.S.A. Ltd. Oil reserves increased slightly from 892,000 bbls to 957,000 bbls gross. The latter figure includes liquids and condensate. Decreases in previously reported oil reserves were offset by the purchase of an interest in the Field's Field in Louisiana. Gas reserves decreased from 385 million cubic metres gross to 164 million cubic metres gross. The decrease in reserves was attributable to a great extent to the postponement and cancellation of projects aimed to develop previously undeveloped proven and probable reserves. These projects were postponed because of the budget constraints of Resources U.S.A.'s joint venture partner. Resources U.S.A.'s activity level was reduced considerably as a result. However, a more selective drilling program resulted in improved success ratios and increased production. Resources U.S.A. will take a more active role in the 1983 program.

Production

	1982	1981
Gas (10^3m^3)	13 003	1 818
Oil (bbls)	38,846	6,027
NGL's (bbls)	21,851	—
Condensate (bbls)	13,059	—

A large portion of the 1982 production increase was attributable to the January, 1982 acquisition of Field's Field in Beauregard Parish, Louisiana.

Resources U.S.A.'s land position has not changed materially during 1982. At December 31, 1981 its land position was 3,260,917 gross acres (316,882 net) located in 25 states. At December 31, 1982, the acreage position was 2,985,271 gross acres (326,129 net) in 25 states.

During 1983 Resources U.S.A. will concentrate its efforts on developing its present leases through selective drilling programs and farm-in arrangements.

Northern Border Pipeline construction in the North Dakota badlands

Pipeline Investments/United States

Great Lakes Gas Transmission Company

TransCanada PipeLines owns a fifty per cent 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 270 000 kilowatts installed at 14 compressor stations.

1982 Operations

Great Lakes' 1982 operations resulted in net income of (U.S.) $25,061,000. This net income compares with (U.S.) $21,357,000 in 1981. Great Lakes delivered for transportation or sale a total of 13.01 billion cubic metres of gas, of which 7.13 billion cubic metres, or 55%, was redelivered to the Company for sale in eastern Canada, with the balance, 5.88 billion cubic metres, delivered to Great Lakes' customers in the United States.

Rates

New rates became effective February 1, 1982, as a result of a settlement agreement reached with all parties in a 1981 rate application.

In December, 1982, Great Lakes filed revised tariff schedules with the Federal Energy Regulatory Commission of the United States (FERC) which proposed increasing its rates to recover higher costs of service. In accordance with normal procedures, FERC suspended the effective date of the new rates until July 1, 1983.

Future Expansion

When the increased exports of natural gas already authorized by Canadian regulatory authorities are approved for import into the United States a further significant expansion of Great Lakes' pipeline facilities will take place.

TransCanada Border PipeLine Ltd.

Through its wholly-owned subsidiary, TransCanada Border PipeLine Ltd., TransCanada owns a 30% partnership interest in the First Phase of the Northern Border pipeline, which extends 1 323 kilometres from Monchy, Saskatchewan, to Ventura, Iowa. Construction of the First Phase was completed on September 1, 1982, with approximate cash expenditures of (U.S.) $1.3 billion. Deliveries of Canadian gas to American markets commenced in September, 1982 and full cost of service tariff came into effect on January 1, 1983.

The Company has the right to acquire an interest of at least 17½% and in certain circumstances an interest of 25% in the Second Phase. The Second Phase contemplates the extension of the pipeline from Ventura to Dwight, Illinois. Plans to file an application for a Construction Certificate in 1982 for the Second Phase have been deferred as a result of uncertainties in the demand for natural gas in the United States.

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 midwestern and eastern regions of the United States. The January, 1983 gas exports decision of the National Energy Board has extended the licence of the primary exporter using the Northern Border facilities to October, 1992. In certain circumstances, these new exports, when approved by the United States regulatory authorities, may lead to an acceleration of the Second Phase.

The Company had made cash expenditures of approximately (U.S.) $117 million to Northern Border up to and including 1982 and does not anticipate further expenditures in 1983.

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 Alaska segment will consist of a gas conditioning plant at Prudhoe Bay and the 1 199 kilometre pipeline extending from Prudhoe Bay to Beaver Creek on the Alaskan-Yukon border, where it connects with the Canadian segment of the System. It is planned that three major oil and gas producers, with gas reserves in the Prudhoe Bay and other adjacent fields, along with nine major natural gas transmission companies, will participate in the financing, construction and operation of these facilities. The Company's interest in the partnership may be adjusted, depending on final financing for the project.

Planned completion of the Alaska segment is currently deferred from 1987 to 1989 due to the depressed economy and uncertain gas markets. The ultimate realization of the Company's investment in the Alaska segment depends upon improving economic and market conditions and the obtaining of adequate financing.

At the end of 1982, the Company had made cash expenditures of approximately (U.S.) $19 million to the Alaska segment.


SASKATCHEWAN
MANITOBA
ONTARIO
TransCanada PipeLines
Foothills Pipe Lines (Sask.) Ltd.
Winnipeg
Emerson
NORTH DAKOTA
MONTANA
MINNESOTA
SOUTH DAKOTA
WISCONSIN
Duluth
Milwaukee
Chicago
Waterloo
Ventura
Des Moines
IOWA
NEBRASKA
Council Bluffs
Dwight
TransCanada PipeLines
Great Lakes Gas Transmission Company
Compressor Stations
Northern Border Pipeline Company
Phase 1
Phase 2
Compressor Stations
Compressor Stations (proposed)
Delivery points
Delivery Point (proposed)
Foothills Pipe Lines (Sask.) Ltd.
Compressor Stations
Compressor Station (proposed)
Existing Pipelines
Connecting Pipeline

Special Projects

Arctic Pilot Project

Initially the Arctic Pilot Project proposed in its application to transport liquefied natural gas from the Arctic Islands to markets in the United States.

On September 1, 1982, the National Energy Board (NEB) adjourned the hearing on the Arctic Pilot Project until the sponsors, Petro-Canada, Nova, an Alberta Corporation, Dome Petroleum and Melville Shipping, could come forward with a definitive proposal for the export of LNG to Europe. In July 1982, the Board granted TransCanada's earlier application for adjournment of its Southern Regasification Terminal Application, an integral part of the original proposal. The application for adjournment was made at the request of the Arctic Pilot Project, who advised that if their investigation of the possible sale of LNG from Melville Island to European markets resulted in the execution of firm sales contracts with European purchasers, then the need in the immediate future for an LNG terminal in southern Canada would no longer exist. Subsequently the Arctic Pilot Project has informed the NEB that its agreement to sell gas to Tenneco for United States markets has expired and will not be extended.

King Christian Island LNG Project

Agreements providing for future co-operation in developing a project to move LNG by ice-breaking LNG carriers from the King Christian Island area to markets in western Europe, have been reached between a group of major west European utilities, the Company and Petro-Canada.

Western LNG Project

In March, 1983 the Alberta Energy Resources Conservation Board recommended approval of an application for a new permit for removal from Alberta of 44 billion cubic metres of natural gas over a 20 year period. This authorization, when approved by the Alberta government, will enable the Company to supply its portion of the gas supply to Dome Petroleum Limited for the Western LNG Project, which will liquefy Canadian gas for sale in Japanese markets. The NEB has also issued an export licence to Dome in respect of the Project, subject to certain conditions,

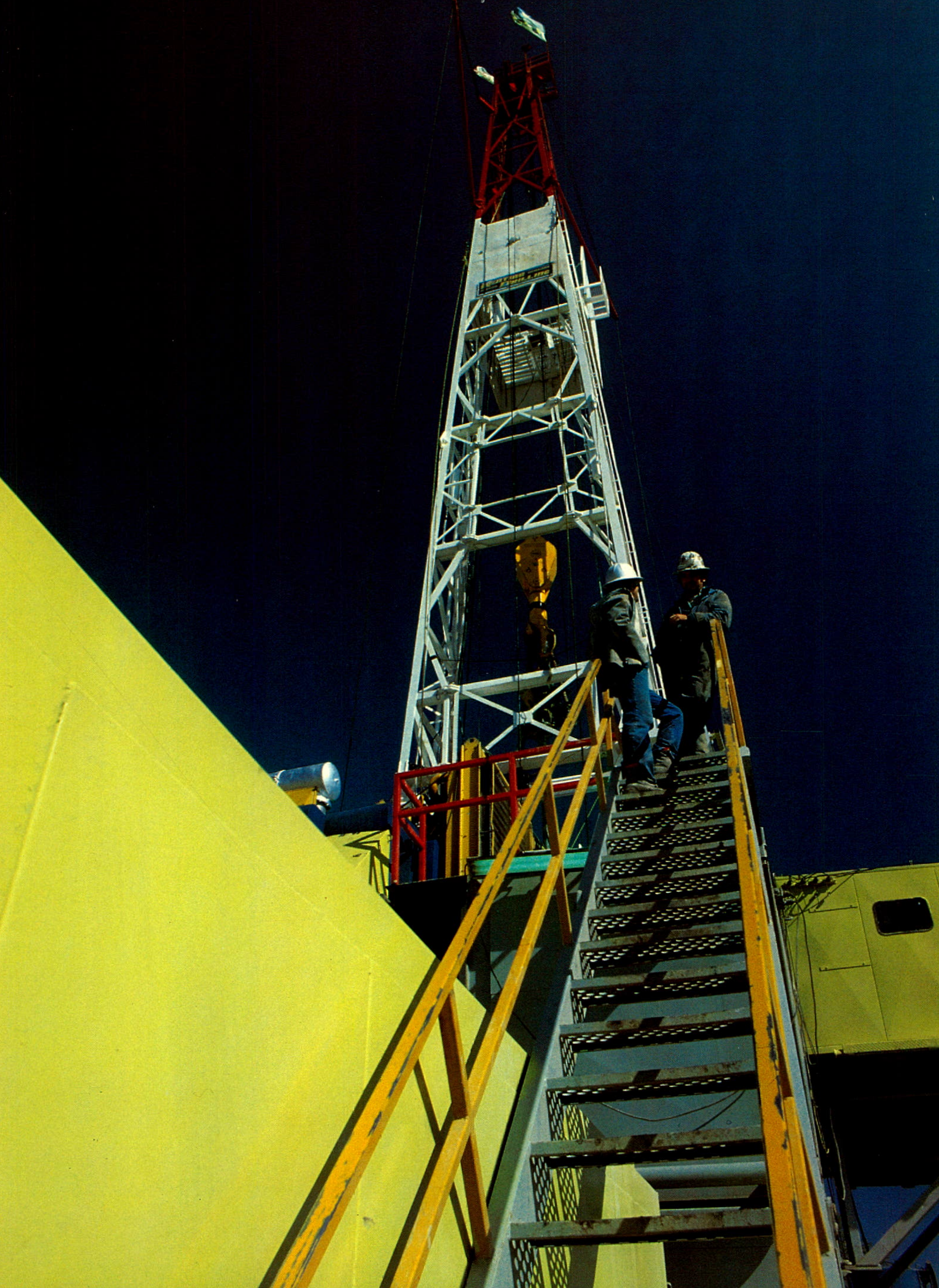
Polar Gas Project

The Polar Gas Project, for which TransCanada PipeLines is the Project Manager, has continued during 1982 to examine the feasibility of alternative options for the transportation of natural gas from the Arctic Islands and the Mackenzie Delta/Beaufort Sea areas to southern markets. On March 17, 1983 Polar Gas announced that it would make applications to the National Energy Board and the Department of Indian Affairs and Northern Development for the first phase of a multi-phase pipeline system to deliver natural gas from the Mackenzie Delta area. The first phase would deliver natural gas by a buried pipeline to the nearest point of interconnection with connecting pipeline systems. In the light of current market and economic conditions, however, recent studies by the project have emphasized the development of a phased approach for connecting smaller volumes to the most accessible markets at the lowest possible cost and providing for expansion in future phases to meet the requirements of domestic and export markets.

Niagara Interstate Pipeline System

The Niagara Interstate Pipeline System project ("NIPS") contemplates the construction of a large-diameter natural gas pipeline and related facilities from the United States-Canada border near Niagara Falls, New York, to a point near Tamarack, Pennsylvania. The facilities will transport Canadian natural gas to Algonquin Gas Transmission Company, Tennessee Gas Pipeline Company ("Tennessee"), Texas Eastern Transmission Corporation ("Texas Eastern") and Transcontinental Gas Pipe Line Corporation ("Transco"). The Company, through its wholly-owned subsidiary TransCanada PipeLine Niagara Ltd. ("TransCanada Niagara"), will initially own a 29% interest in the partnership with the remainder to be owned by subsidiaries of Transco, Tennessee and Texas Eastern. The total cost of the NIPS project is estimated at (U.S.) $323 million.

Dome Petroleum drilling rig
near Caroline, Alberta



Corporate Organization

A number of changes have been made in senior management responsibilities during 1982 and early 1983 to reflect the diversification of the Company.

Mr. A. Bercovici, formerly Vice-President and General Manager, TransCan Holdings Ltd., was appointed President, TransCan Holdings and Managing Director of TCPL Nederland B.V.

Mr. R. F. Sim became Vice-President, Corporate Taxation, with responsibility for all aspects of taxation and tax planning.

Mr. K. G. Whiteside became Vice-President, Corporate Planning and Control and will co-ordinate all aspects of Corporate Budgeting, Accounting, Forecasting and Control.

Mr. A. A. Wilkins, formerly Vice-President, Gas Supply, has been appointed a Vice-President of TCPL Resources.

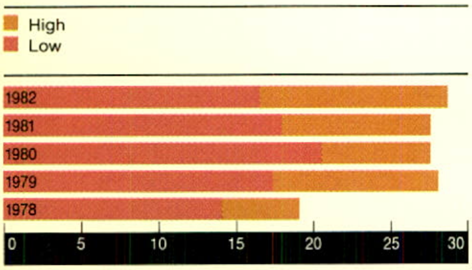
Shareholders

During 1982, Dome Canada Limited of Calgary, Alberta, was the Company's largest shareholder, with 23.01% of the Company's outstanding common shares, followed by Dome Investments Limited, a wholly-owned subsidiary of Dome Petroleum, with 11.8% and Dome Petroleum Limited with 11.21%. In March, 1983, Dome Canada, Dome Petroleum Limited and Dome Investments Limited sold 11,000,000 of the shares of the Company held by them and after the sale Dome Canada remained the Company's largest shareholder, with 11.85% of the Company's outstanding common shares, followed by Dome Investments Limited with 6.44% and Dome Petroleum Limited with 3.17%. As a result of the sale, it is estimated that the Company acquired approximately 4,000 new shareholders. Shareholders resident in Canada held 98.7% of the Company's outstanding common shares at December 31, 1982. During the year the market price per common share varied from a low of \$16½ to a high of \$28⅝. TransCanada's common shares are listed for trading on the Vancouver, Alberta, Winnipeg, Toronto and Montreal Stock Exchanges.

Geographical Share Distribution
(As of December 31, 1982)

	Number of Share holders	Number of Shares
Newfoundland	44	49,758
Nova Scotia	601	409,326
Prince Edward Island	73	23,780
New Brunswick	311	102,013
Quebec	2,610	4,176,309
Ontario	9,706	13,989,257
Manitoba	924	1,657,425
Saskatchewan	539	125,907
Alberta	2,320	22,137,656
British Columbia	3,151	1,550,819
Northwest Territories	3	650
Yukon Territories	4	81
Total Canadian	20,286	44,222,981
U.S.A.	1,909	459,608
Other Countries	183	107,262
Total Non-resident	2,092	566,870
Overall Total	22,378	44,789,851

High/low share price
Dollars



Gas plant at Edson, Alberta in which the Company has acquired an interest.

Employees

At the close of 1982, TransCanada PipeLines employed on a regular basis 1,798 men and women across the country. In addition to this total, 404 University, College and High School students were hired as part of the Company's annual summer student program.

TransCanada is proud of the vital contributions made by all personnel towards the safe and efficient operation of Company activities throughout the year. The effectiveness of employees was enhanced during the year by the Company's continued concern and commitment to the development of its human resources.

Consistent with this philosophy, just over one out of every three employees were enrolled in formal training programs during 1982. A total of 169 participated in supervisory and management programs, 222 attended special administrative and technical courses and a further 124 employees qualified for 100 per cent reimbursement under the Company's Education Refund Plan by successfully completing programs of study on a wide variety of job-related subjects.

To assist employees nearing retirement, the Company once again conducted its Retirement Communications Program. All together, 26 employees and their spouses attended the 1982 edition, where they received valuable information on planning for the years ahead. As well, 79 new members were welcomed into the Quarter Century Club in 1982. The total number of club members has now reached 109.

All employees are eligible to become shareholders of the Company through the Stock Savings Plan. The Plan had purchased a total of 352,717 common shares at the end of 1982.

European Operations

As a result of its growing involvement with European financial markets and the expansion of its oil and gas exploration activities outside North America, TransCanada has established business offices for new international subsidiaries in The Netherlands and Switzerland, under the direction of Mr. A. Bercovici, Managing Director.

In addition to providing funds as required for the growing operations of the Company in the United States through the Company's wholly-owned subsidiary, TCPL Nederland B.V., the oil and gas operations of the Company in Indonesia and other oil and gas operations outside North America, are carried on through wholly-owned Swiss subsidiaries.

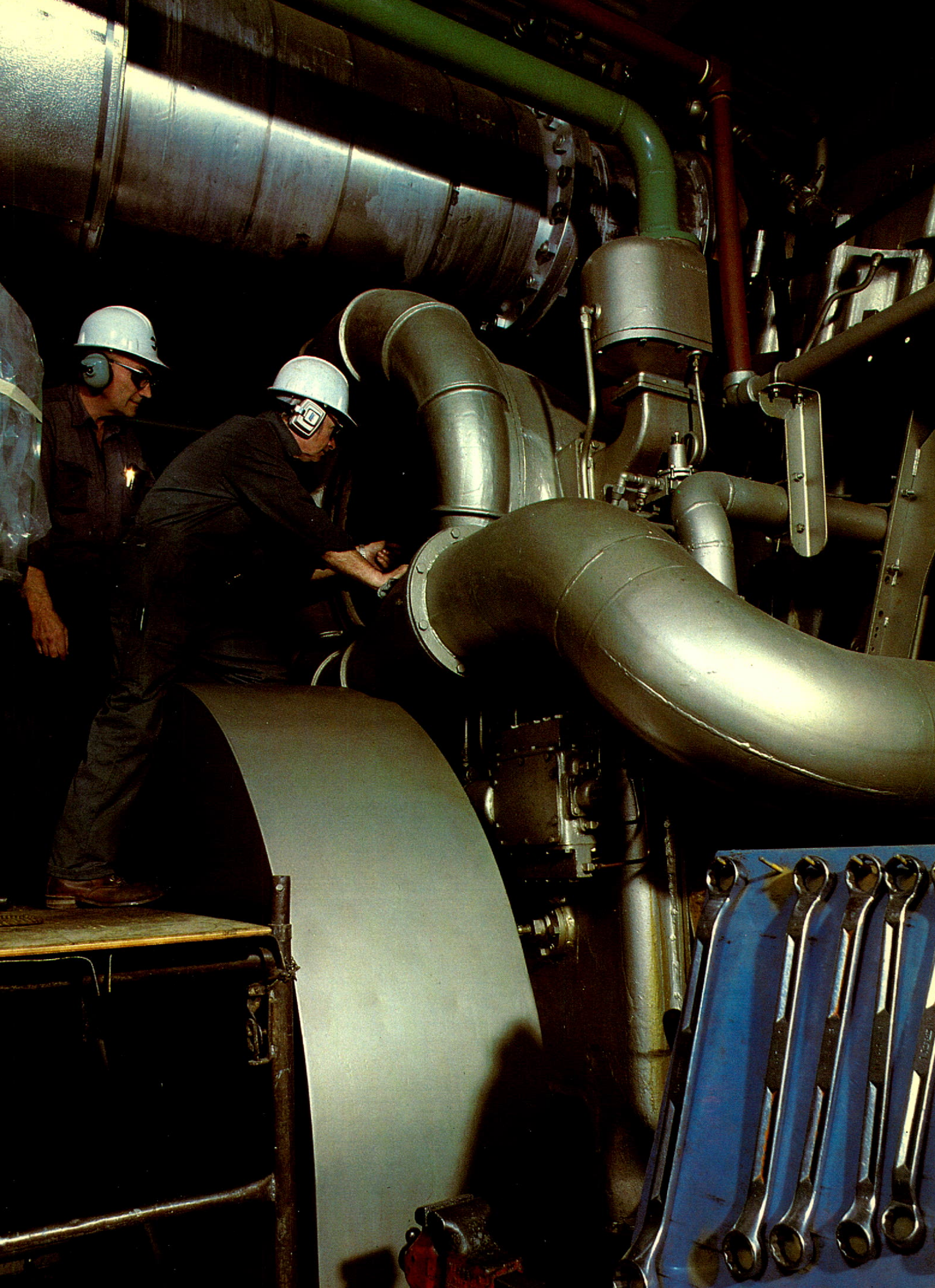
International Subsidiaries and Affiliates

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

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

Switzerland
Cancarb AG
International PipeLine Engineering Limited
TCR Madur AG
TCR Malac AG
TCR Natun AG
TCR Sumat AG
TCPL Investments AG
TCR Resources AG

Compressor station maintenance at Thunder Bay, Ontario



Capital markets in 1982, particularly in the first six months of the year, were unsettled. The Canadian capital market for corporate issuers of debt continued to be essentially closed due to the more attractive returns available to investors from short-term instruments. In this environment, the Company arranged for $1.261 billion of external financing, excluding $981 million from the refinancing of the Company's take or pay obligations to producers. The table below details the financings completed by the Company in 1982.

Issue	Maturity	Interest Rate
50,000,000 Swiss Franc Notes	1989	7¼%
100,000,000 Swiss Franc Notes	1994	7%
U.S. $25,000,000 Promissory Note	1987	17⅜%
£25,000,000 First Mortgage Pipe Line Bonds	2007	16½%
U.S. $125,000,000 First Mortgage Pipe Line Bonds	1997	16¾%
U.S. $100,000,000 Notes	1992	16%
$600,000,000 Bank Loan	1990	Variable Rate
U.S. $164,750,000 Bank Loan	1987	Variable Rate

The $600,000,000 bank loan was arranged through a partnership 50% owned by the Company. The loan, which is non-recourse to the Company, is fully secured by oil and gas interests owned by the partnership. As a result, the Company's equity carrying value of its investment in oil and gas properties is net of these non-recourse bank loans.

As more fully described in Note 1 to the financial statements on page 45, the Company structured a program (the Topgas program) in 1982 that removed substantially all the Company's investments for future gas supply from its balance sheet. As a result of the Topgas program, which involved a $2.3 billion financing, the largest single private sector transaction in Canadian history, the Company received $981 million. Of this amount, $663 million was used to repay bank indebtedness associated with the take or pay payments previously made by the Company. The remaining $318 million was used to assist the financing of the 1982 utility capital expenditure program.

In 1982 the Company re-entered the commercial paper market in Canada with the issuance of $50 million of short-term promissory notes. At the end of 1982 the Company had lines of credit totalling $265 million. Average borrowings under these lines in 1982 were approximately $84 million.

In December, 1982 the Company's Board of Directors authorized a Dividend Reinvestment and Share Purchase Plan for its preferred and common shareholders and a Stock Dividend and Share Purchase Plan for its common shareholders. Under the Dividend Reinvestment and Share Purchase Plan, shareholders may reinvest their dividends in common shares of the Company at 95% of a specified average market price and may also invest up to $3,000 per quarter in common shares of the Company at a specified market price. Under the Stock Dividend and Share Purchase Plan, common shareholders may receive their dividends in common shares of the Company at 95% of a specified average market price, and may also invest up to $3,000 per quarter in common shares at a specified market price. Under both plans, no commissions or expenses are payable by the shareholder.

It is forecast that external capital requirements of the Company will be minimal in 1983. This will provide the Company with an opportunity to further strengthen its balance sheet, a process which began in the fall of 1982 with the completion of the Topgas transaction.

Financial Commentary

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 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 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 38 to 52 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 52 outlines the scope of their examination and their opinion on the financial statements.

1982 Financial Review

Net Income Applicable to Common Shares

In 1982, net income applicable to common shares increased by $35.6 million, or 28%, when compared to 1981. Earnings per common share increased to $3.62 in 1982 from $2.85 in 1981, an increase of 27%.

Income Before Financial Charges, Income Taxes and Provision for Preferred Dividends

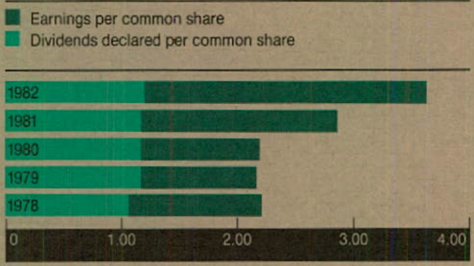
Income before financial charges, income taxes and provision for preferred dividends increased by $147.5 million in 1982. Of this amount, $129.7 million was contributed by Utility operations, $24.5 million by equity investments in other pipelines, $9.3 million by equity investments in oil and gas joint ventures and $3.0 million by miscellaneous other income and expenses. Offsetting these increases was a $19 million decrease in the amount recovered from the Company's Alberta cost of service because of lower take or pay financing costs in 1982 due principally to the refinancing in October, 1982 of the Company's take or pay payments ("the Topgas Program").

Of the $129.7 million contributed by Utility operations, $99.7 million was primarily a result of significant additions to rate base which took place over the last two years coupled with increases in the approved rate of return on rate base. During the last two years this return has been increased twice, moving from 11.1% to the present rate of 13.88%.

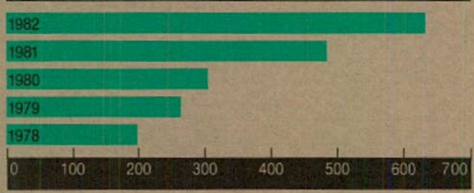
The remaining $30 million contributed by Utility operations represents return on facilities under construction. This return is called an allowance for funds used during construction ("AFUDC") and is calculated monthly on the amount invested in facilities that are still being constructed using a rate equal to the rate of return on rate base. Variances in AFUDC on a year over year basis can result from a combination of the level of construction, the timing of construction and the rate used to compute the allowance.

Of the $24.5 million increase contributed by investments in other pipelines, $12.0 million comes from the Company's interest in Trans Québec & Maritimes Pipeline Inc. ("TQM"). The Company's income from the Northern Border segment and the Saskatchewan section of the Alaska Natural Gas Transportation System ("ANGTS") contributed an additional $9.2 million and $5.3 million respectively. In addition, the improved earnings from the operations of Great Lakes Gas Transmission Company ("Great Lakes") contributed $3.3 million. These increases were offset by a decrease in income from the Alaska segment of ANGTS of $5.3 million.

Net income per common share
Dollars



Income before financial charges, income taxes and preferred dividends
Millions of dollars



TQM, which is constructing and operating the Trans Québec & Maritimes Pipeline, commenced operations in 1982 and has recorded operating revenues and expenses as well as AFUDC.

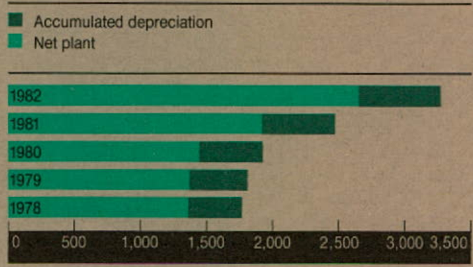
The improvement in income from the Northern Border segment of ANGTS represents increased equity AFUDC. Construction of the First Phase of the Northern Border segment, which extends from Monchy, Saskatchewan to Ventura, Iowa, was completed in September, 1982. All operating revenues and expenses relating to the First Phase were capitalized until January, 1983 at which time a full cost of service tariff went into effect.

Foothills Pipe Lines (Sask.) Ltd., which constructed the Saskatchewan section of the Canadian segment of ANGTS extending from Empress, Alberta to Monchy, Saskatchewan, began operations in 1982 in conjunction with the commencement of operations of the Northern Border segment. The increase in the Company's income from its interest in the Canadian segment is primarily AFUDC and reflects earnings for the first full year of the Company's investment.

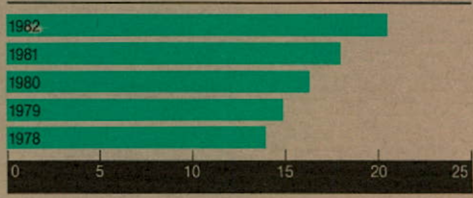
As the expected completion of the Alaska segment of ANGTS has been deferred from 1987 to 1989, the Company discontinued recording AFUDC in the first quarter of 1982. In 1981, the Alaska segment partnership recorded in its natural gas transmission plant under construction and partnership equity accounts costs related to expenditures incurred previously by certain of the partners, including the Company, who were also co-sponsors of another project. The partnership subsequently applied to the Federal Energy Regulatory Commission of the United States ("FERC") for approval of these costs as a proper rate base item in the Alaska segment. In 1982, the FERC ruled against inclusion. Accordingly, the Company has reduced the carrying value of its investment in the Alaska segment during 1982 by $14.8 million, with a corresponding reduction in a previously recorded deferred credit. This adjustment had no impact on reported earnings. In addition, the Company also reversed $2.5 million of related AFUDC previously recorded in income against 1982 earnings.

Income before income taxes from oil and gas investments increased by $9.3 million in 1982. The volume of gas sales in 1982 rose by approximately 130% over 1981, while the volume of oil sales increased by approximately 230%. These increases are primarily attributable to the fact that in March, 1982 the Company acquired a 12½% undivided interest in substantially all of the assets of Hudson's Bay Oil & Gas Company Limited ("HBOG"). This acquisition was financed with non-recourse borrowings. Financial charges on these borrowings of $75.2 million, offset by interest capitalized

Plant, property and equipment growth
Millions of dollars



Common shareholders' equity per share at year end
Dollars



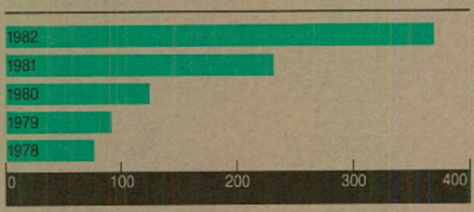
of $45.6 million, are included in income from oil and gas investments. Capitalization of interest on certain other non-producing properties is recorded in the accounts of the Company as a reduction of Financial Charges in the amount of $12.0 million.

Financial Charges
The Company's total interest costs before interest capitalization increased by $84 million over 1981. This increase reflects the added financings related to the utility construction program and investments in pipeline joint ventures. The effect of the new debt was partially offset by the lower average cost of short-term borrowings in 1982 and by the repayment in the final quarter of 1982 of the Company's term loans related to take or pay gas. Interest costs associated with take or pay obligations amounted to $96 million in 1982 compared to $120 million in 1981 and were recovered through the Company's Alberta cost of service. Interest costs associated with financing regulated operations are generally recoverable through the ratemaking process.

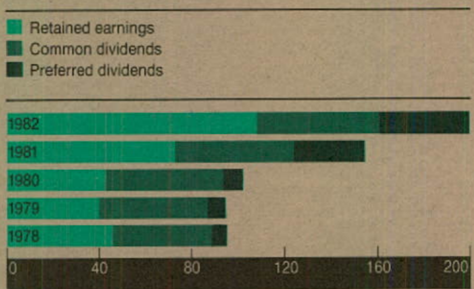
Liquidity and Capital Resources
Earnings and related cash flow from the Company's wholly-owned regulated operations are primarily affected by the rate of return on rate base approved by the National Energy Board, including a return on common equity and the actual performance of the Company in the period during which rates are effective. The Company's rates for gas sales and transportation are designed in a way which will provide the Company with the opportunity of earning its approved return on rate base. Rates 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 estimates costs, the Company may earn more or less than its approved return on rate base.

Funds generated by operations and equity investments amounted to $326 million in 1982, compared to $303 million in 1981. The modest increase reflects the

Financial charges (net)
Millions of dollars



Distribution of net income
Millions of dollars



reduction in cash flow brought about by the change in accounting policy with respect to income taxes. As the result of a decision made by the National Energy Board, the Company was required to adopt the taxes payable method of recording income taxes applicable to its Canadian utility operations for ratemaking and accounting purposes, effective August 1, 1982. Although the change in accounting policy has reduced cash flow, the Company's after tax profit has not been affected.

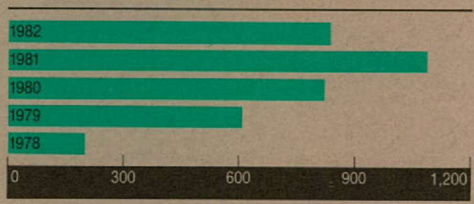
As a result of the implementation of the Topgas Program, most of the Company's take or pay payments were refunded in 1982 by producers. The Company was required, in turn, to apply a substantial portion of these funds to repay all of its term bank loans previously incurred to finance the take or pay payments. Nearly all of the Company's take or pay obligations have been assumed by a consortium of banks through Topgas Holdings Limited.

With the Northern Border segment and Saskatchewan section of ANGTS coming into service, the Company will be provided with a secure long-term source of cash flow similar to its existing regulated utility operations.

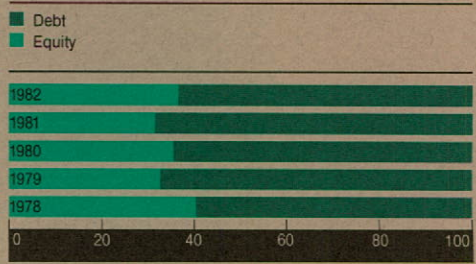
Capital expenditures amounting to $833 million were made in 1982, compared to $1.082 billion in 1981. There was a substantial decrease in take or pay payments in 1982 because of the fact that the Company was not obliged to make any further take or pay payments to producers participating in the Topgas Program. The majority of capital expenditures made in 1982 relate to the construction of utility-related facilities. Approximately half of these expenditures were financed by additional first mortgage pipe line bond issues and by U.S. dollar notes.

The decline in capital expenditures relating to investments in pipeline joint ventures was largely due to the decline in the level of capital contributions to the First Phase of the Northern Border segment of ANGTS in 1982. In addition, a portion of the funds which had previously been invested in TQM was refunded to the Company during the year. Expenditures relating to pipeline joint ventures include a loan made in 1982 to Great Lakes. The Company's capital expenditures relating to oil and gas joint ventures in 1982 reflect the cost of the properties acquired from HBOG net of the non-recourse bank loans arranged to finance the acquisition.

Capital expenditures
Millions of dollars



Debt/equity ratio
Percent



Consolidated Income
Year ended December 31, 1982 (with comparative figures for 1981)

	1982	1981
	($000)	($000)
Revenues		
Gas sales — domestic	2,382,709	2,082,199
— export	981,099	1,261,546
Gas transportation and other	103,107	61,152
	3,466,915	3,404,897
Costs and Expenses		
Cost of gas sold	2,425,425	2,502,670
Transmission, operating and general	551,994	485,171
	2,977,419	2,987,841
Income from Investments		
Pipelines	52,909	28,445
Oil and gas	30,123	20,781
	83,032	49,226
Other Income		
Allowance for funds used during construction	45,232	15,025
Other (net)	15,988	4,925
	61,220	19,950
Income before the undernoted items	633,748	486,232
Financial Charges		
Interest on long-term debt (net)	364,802	216,225
Other interest and finance costs	3,508	13,446
	368,310	229,671
Income Taxes		
Current	12,845	—
Deferred	53,675	102,489
	66,520	102,489
Net Income for the Year	198,918	154,072
Less provision for dividends on preferred shares	37,790	28,499
Net Income Applicable to Common Shares	161,128	125,573
Net Income per Common Share	$3.62	$2.85

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

Consolidated Financial Position
December 31, 1982 (with comparative figures at December 31, 1981)

	1982	1981
	($000)	($000)
Assets		
Current Assets		
Cash and temporary cash investments	99,919	35,763
Accounts receivable	592,246	437,442
Inventories — at cost	119,057	89,560
Prepayments and deposits	4,806	4,150
	816,028	566,915
Payments on Future Gas Supply (Note 1)	42,510	1,013,291
Investments		
Pipelines (Note 2)	394,912	344,371
Oil and gas (Note 3)	740,581	687,597
	1,135,493	1,031,968
Plant, Property and Equipment — at cost	3,266,782	2,465,107
Less accumulated depreciation	615,998	544,769
	2,650,784	1,920,338
Deferred Charges	72,094	53,788
	4,716,909	4,586,300
Liabilities and Shareholders' Equity		
Current Liabilities		
Notes payable	199,999	106,200
Accounts payable	642,708	487,623
Interest accrued	96,532	56,575
Dividends payable	23,475	21,730
Long-term debt due within one year	41,288	44,687
	1,004,002	716,815
Long-Term Debt (per Schedule and Note 4)	2,152,875	2,458,772
Deferred Income Taxes	297,287	246,569
Shareholders' Equity		
Capital stock (Note 5)	452,767	463,032
Contributed surplus	275,495	274,711
Retained earnings	534,483	426,401
	1,262,745	1,164,144
	4,716,909	4,586,300

On behalf of the Board:

John Beddome

J.M. Beddome, 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, 1982 (with comparative figures for 1981)

	1982	1981
	($000)	($000)
Contributed Surplus		
Balance at beginning of year	**274,711**	273,771
Credit resulting on redemption of preferred shares	**784**	940
Balance at end of year	**275,495**	274,711

	1982	1981
	($000)	($000)
Retained Earnings		
Balance at beginning of year	**426,401**	353,670
Net income for the year	**198,918**	154,072
	625,319	507,742
Dividends declared		
Preferred	**37,855**	30,171
Common	**52,981**	51,170
	90,836	81,341
Balance at end of year	**534,483**	426,401

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

Consolidated Source of Funds for Capital Expenditures

Year ended December 31, 1982 (with comparative figures for 1981)

	1982 ($000)	1981 ($000)
Funds Generated		
Net income	**198,918**	154,072
Depreciation	**77,019**	58,276
Deferred income taxes	**53,675**	102,489
Equity in undistributed income from investments net of funds generated	**28,298**	(21,856)
Other	**(31,476)**	10,131
Funds generated by operations and equity investments	**326,434**	303,112
Less: Funds generated by equity investments in unincorporated joint ventures	**82,007**	27,370
Funds generated by operations	**244,427**	275,742
Funds received from take or pay refinancing	**981,496**	—
Less:		
Dividends on preferred and common shares	**90,836**	81,341
Reduction of long-term debt	**865,516**	60,682
Net funds generated	**269,571**	133,719
Funds from New Financing		
Long-term debt	**797,541**	996,325
Preferred shares	**—**	148,098
Common shares	**7,161**	7,208
	804,702	1,151,631
Less refinancing	**230,000**	235,720
Net funds from new financing	**574,702**	915,911
Funds from Other Sources (net)		
Decrease in working capital	**38,074**	59,820
Deferred charges and other	**(49,323)**	(27,152)
	(11,249)	32,668
Funds Available for Capital Expenditures	**833,024**	1,082,298
Capital Expenditures		
Plant, property and equipment	**772,493**	533,417
Investments — pipelines	**26,955**	239,226
— oil and gas	**22,861**	128,429
Payments on future gas supply	**10,715**	181,226
Total Capital Expenditures	**833,024**	1,082,298

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

Consolidated Schedule of Long-Term Debt December 31, 1982 (with comparative figures at December 31, 1981)

	1982	1981
	($000)	($000)
First Mortgage Pipe Line Bonds		
Due 1983 — 6¼% U.S. series — U.S. $4,454,000	**5,476**	10,975
— 6¾% Canadian series	**2,138**	4,647
Due 1985 — 5⅝% U.S. series — U.S. $6,400,000	**7,244**	9,564
Due 1987 — 7⅛% U.S. series — U.S. $36,000,000	**39,814**	46,764
Due 1992 — 9¼% Canadian series A	**54,300**	59,250
— 9¼% Canadian series B	**23,200**	25,440
Due 1993 — 8⅞% Canadian series A	**38,411**	41,910
— 8⅞% Canadian series B	**6,080**	6,640
Due 1996 — 16% U.S. series — U.S. $400,000,000	**482,804**	341,246
Due 1997 — 16¾% U.S. series — U.S. $125,000,000	**158,060**	—
Due 2007 — 16½% U.K. series — £25,000,000	**54,708**	—
	872,235	546,436
Sinking Fund Debentures		
Due 1990 — 10% series A	**29,691**	33,278
— 9¾% series B	**37,159**	41,216
Due 1991 — 9% series C	**29,746**	34,979
Due 1992 — 8⅞% series D	**67,782**	71,432
Due 1993 — 9% series E	**72,894**	77,587
Due 1995 — 11½% series F	**41,702**	44,563
Due 1997 — 9.60% series G (Sinking fund commences in 1983)	**63,368**	66,844
Due 1996 — 18% series H (Sinking fund commences in 1987)	**75,000**	75,000
	417,342	444,899
Notes		
Due 1986 — 5¾% — Swiss francs 100,000,000	**61,150**	66,430
Due 1987 — 6% — Swiss francs 50,000,000	**30,575**	33,215
Due 1989 — 7¼% — Swiss francs 50,000,000	**30,575**	—
Due 1991 — 5½% — Swiss francs 100,000,000	**61,150**	66,430
Due 1994 — 7% — Swiss francs 100,000,000	**61,150**	—
Due 1988 — 17¾% — U.S. $75,000,000	**89,965**	89,965
Due 1989 — 16% — U.S. $100,000,000	**118,078**	118,078
Due 1992 — 16% — U.S. $97,810,000	**119,216**	—
	571,859	374,118
Term Loans		
Due 1983 - 1987	**234,121**	1,068,480
Term Promissory Notes		
Due 1986 — 15½% U.S. series — U.S. $20,000,000	**24,588**	24,113
— 15½% Canadian series	**5,000**	5,000
Due 1987 — 17⅜% U.S. series — U.S. $25,000,000	**30,735**	—
	60,323	29,113
Subordinated Debentures		
Due 1987 — 5.60% U.S. series — U.S. $11,091,000	**11,246**	11,636
— 5.85% Canadian series	**27,037**	28,777
	38,283	40,413
	2,194,163	2,503,459
Less: Long-term debt due within one year	**41,288**	44,687
	2,152,875	2,458,772

See Note 4 to consolidated financial statements.

Summary of Significant Accounting Policies December 31, 1982

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 and the United States, as well as minor oil and gas interests in other countries.

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 a 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 during the period reduce the carrying value of the investment.

The Company follows the full-cost method of accounting for 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 land acquisition costs, geological and geophysical expense, interest and other carrying charges of non-producing property, and costs of drilling both productive and non-productive wells. The amount of costs that have been capitalized do not exceed the value of the underlying interests in oil and gas properties.

The Company employs the revenue method of depletion, whereby provisions for depletion and depreciation of production facilities are allocated to individual periods in the same proportion as current revenue is to the total estimated revenue from proven reserves of oil and gas.

Costs of unusually significant acquisitions of non-producing properties are initially excluded from depletion 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.

The Company capitalizes interest on unusually significant acquisitions of unproved 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 economical proved reserves associated with the properties. Interest is also capitalized on unusually significant acquisitions of oil and gas properties which were capable of, but had not commenced production at the date of acquisition. Capitalization of interest on these properties is terminated when production commences.

Regulation — Matters such as rates, 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 July 28, 1982, the NEB authorized an increase in the Company's tolls which included an increase in the Company's overall rate of return on rate base to 13.88% from 12.63%. These increases became effective on August 1, 1982, for export sales and transportation services, and September 1, 1982, for domestic gas sales, the effective date the Governor-in-Council approved increases in the authorized wholesale prices for domestic sales.

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

Plant, property and equipment — The Company's provision for depreciation expense for its 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 lives 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 at various rates for general plant equipment.

Translation of foreign currency — The Company's U.S. dollar foreign currency balances related to its Canadian utility operations have been translated to their Canadian equivalent using rates in effect at the balance sheet date for current assets and liabilities and at the greater of par or the rate in effect on dates of issue for long-term debt due after one year. The pound sterling bonds related to utility operations have been translated to the Canadian equivalent at the rate of exchange in effect on the date of issue. Foreign exchange gains and losses on utility related debt are included in net income as they are recovered through the ratemaking process. These accounting practices are prescribed by the NEB for the Company's regulated utility operations.

For all other operations of the Company, current assets, current liabilities, and long-term monetary assets and liabilities, including the Swiss franc notes, are translated at the rates in effect at the balance sheet date. Other assets and liabilities are translated at rates prevailing at the respective transaction dates. Revenues and expenses are translated at average exchange rates in effect during the year except for depletion, depreciation and amortization charges which are translated at the historic rates used for the related assets. Foreign exchange gains and losses are included in the net income of the current year except for unrealized exchange gains and losses related to the translation of non-utility long-term monetary assets and liabilities which are amortized over the remaining lives 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 this method, the Company makes full provision for income taxes deferred as a result of claiming certain deductions for income tax purposes in excess of amounts charged to income for accounting purposes.

For the Company's Canadian utility operations regulated by the NEB, the use of the normalized or deferral method of tax allocation accounting was prescribed from August 1, 1978, to July 31, 1982, for both ratemaking and accounting purposes. Prior to August 1, 1978, and subsequent to July 31, 1982, the NEB prescribed the taxes payable method of recording income taxes for such operations. In its 1982 decision, the NEB noted that no adjustments would be made at this time for deferred taxes recovered through rates in prior periods. The amount of deferred taxes so recovered totalled approximately $77 million.

As allowed by the relevant income tax provisions and regulations, certain deductions were claimed for income tax purposes in the Company's utility operations in excess of the amounts charged to income for accounting purposes. As a result of using the taxes payable method, the Company has not recorded in its accounts nor recovered in its rates any provision for income taxes relating to its Canadian utility operations for the period prior to August 1, 1978. Subsequent to July 31, 1982, income taxes deemed payable on Canadian utility operations have been recovered in rates. If the normalized method of tax allocation accounting had been permitted by the NEB for ratemaking and accounting purposes, additional provisions for income taxes would have been recorded to an accumulated amount of $263,800,000 related to the period to July 31, 1978, and $22,576,000 related to the period from August 1, 1982 to December 31, 1982.

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.

Notes to Consolidated Financial Statements December 31, 1982

1. Payments on Future Gas Supply

The Company purchases gas from approximately 600 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 quantities of gas. As the contracted supply has exceeded the available market in recent years, payments ("take or pay payments") had been made by the Company for gas not taken ("prepaid gas"). For the five contract years ended October 31, 1982, the Company implemented a program under which the majority of producers, with their concurrence, were allocated an equitable share of the Company's available market. For the two contract years ended October 31, 1982, the program was amended, with the producers' concurrence, to provide for a 20% reduction in the Company's obligation to take gas ("deferred gas").

At December 31, 1981, the Company had made take or pay payments to its producers totalling $1.013 billion. These payments had been financed through term loans of $733 million and the issuance of retractable preferred shares totalling $280 million ("take or pay financings"). All interest and dividend costs associated with these financings were recovered by the Company through its Alberta cost of service.

During 1982 the Company concluded arrangements (the "Topgas Program") with a syndicate of Canadian and foreign banks and substantially all of its producers to refinance its take or pay payments.

Under the Topgas Program, Topgas Holdings Limited ("Topgas") an Alberta corporation controlled by the banking syndicate was incorporated as a financing vehicle for the banking syndicate. The program requires Topgas to: (i) make advances to producers in an amount equal to that previously advanced to the producers by the Company; (ii) make advances to the producers in respect of the deferred gas for the 1980/81 contract year which the Company had been excused from making under the previous allocation program; and (iii) make advances to the producers in respect of take or pay gas incurred by the Company in the 1981/82 contract year without taking into account the deferred gas. In addition, the producers are required to refund to the Company all take or pay payments previously made to them by the Company and to forego any further take or pay payments except at the reduced level hereinafter referred to during the term of the Topgas Program. The Company is required to apply a portion of the refunded take or pay payments to discharge all term bank loans previously incurred to finance such take or pay payments.

Pursuant to the Topgas Program, Topgas advanced to producers on October 5, 1982 approximately $1.401 billion and on December 30, 1982 approximately $879 million. As a result of the implementation of the program substantially all of the Company's prepaid gas has been financed by Topgas and all of the Company's term bank loans incurred for this purpose were repaid. A third and final closing is scheduled for March 1, 1983. The funds required to be advanced by Topgas under the Topgas Program cannot exceed approximately $2.3 billion.

Recovery of the amounts advanced to producers by Topgas will be effected in instalments commencing November 1, 1984 through the nomination for delivery by the Company of prepaid gas. A portion of the purchase price payable by the Company to the producers for prepaid gas will be paid directly by the Company to Topgas. 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 is 10% of the outstanding prepaid gas (calculated on a heat content basis) as at December 31, 1982. The recovery of prepaid gas will be accelerated proportionately to increases in total sales of gas by the Company over the total sales in the 1981/82 contract year.

The interest costs associated with the funds advanced by Topgas to the producers are being included in the Company's Alberta cost of service and remitted to Topgas by the Company.

Under the Topgas Program, the Company's obligation to make further take or pay payments will arise only if the Company is unable to nominate the lesser of: (i) 60% of the minimum annual obligation for the 1981/82 contract year; and (ii) 75% of the Company's minimum annual obligation calculated under the contract year in respect of the year in question. This 75% threshold will only be relevant in the case of a producer whose ability to deliver under a contract has declined subsequent to the 1981/82 contract year. TransCanada nominated for delivery during the 1981/82 contract year approximately 67% of its minimum contracted volumes.

Recourse to the Company under the Topgas Program is as follows:

(a) the Company will indemnify Topgas to a maximum of $300 million for, in effect, any losses arising due to the inability or failure of a producer to deliver prepaid gas;

(b) the Company will indemnify Topgas for any losses suffered as a result of a failure or breach by the Company of its obligations under the program, or by reason of the failure of Topgas to recover its interest costs in the Company's Alberta cost of service or from any other source.

The Company is also continuing 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 Program.

As approved by the Alberta Petroleum Marketing Commission, interest on term loans and dividends on preferred shares related to the financing of prepaid gas prior to the implementation of the Topgas Program and interest on loans relating to advances made by the Company to those producers not in the Topgas Program, 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. Term loan interest has been recovered in the amount of $96 million and $119.5 million for the years ended December 31, 1982 and 1981 respectively. For the years ended December 31, 1982 and 1981, preferred dividends of $24.4 million and $22 million respectively, and related income taxes, have been recovered through the Alberta cost of service.

2. Investments — Pipelines

The investment at December 31 and share of earnings in regulated pipeline joint ventures for the twelve months ended December 31, 1982 and 1981 respectively, are set out below in thousands of dollars:

	1982		1981	
	Investment	Equity Earnings	Investment	Equity Earnings
Great Lakes Gas Transmission Company:				
—shares	**47,448**	**15,352**	61,420	12,072
—loans	**61,470**	**—**	—	—
Alaska Natural Gas Transportation System:				
—Northern Border Segment	**175,868**	**21,840**	153,873	12,659
—Alaska Segment	**24,271**	**(1,888)**	32,672	3,488
—Canadian Segment (Saskatchewan section)	**33,564**	**5,564**	28,000	226
Trans Québec & Maritimes Pipeline	**52,291**	**12,041**	68,406	—
	394,912	**52,909**	344,371	28,445

Great Lakes Gas Transmission Company ("Great Lakes")

The Company shares equally with American Natural Resources Company in the ownership of Great Lakes which is a United States corporation. 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 investment in Great Lakes includes a loan of (US) $50 million made in March 1982 which is repayable in September 1986. The interest rate on this loan to December 31, 1982, was 15.625%, and effective January 1, 1983, became 12.625%.

The following sets out summarized 1982 and 1981 financial information for Great Lakes stated in thousands of United States dollars:

	1982	1981
Natural gas transmission plant (net)	**333,376**	307,873
Current liabilities less current assets	**(36,752)**	(34,376)
Deferred credits (net)	**(39,666)**	(27,074)
Long-term debt	**(162,678)**	(127,204)
Shareholders' equity	**94,280**	119,219
Revenues	**536,438**	522,434
Expenses	**511,377**	501,077
Net income	**25,061**	21,357

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 (US) $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.

The approval of Northern Border's Incentive Rate of Return ("IROR") by the Federal Energy Regulatory Commission ("FERC") is expected by mid-1983. It is anticipated that the IROR will be approximately 17%.

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 (US) $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 to 40% of the total advances at final maturity in 1993 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 Company's earnings in the Northern Border segment represent equity AFUDC computed at 13%.

The following sets out summarized 1982 and 1981 financial information for the Northern Border partnership stated in thousands of United States dollars:

	1982	1981
Natural gas transmission plant	**1,299,091**	937,673
Deferred charges	**5,286**	4,824
Current liabilities less current assets	**(42,037)**	(46,574)
Long-term debt	**(781,067)**	(473,900)
Partners' equity	**481,273**	422,023

(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. Using cost estimates developed in 1981, and subject to the partnership arranging appropriate financing for the project, the Company's investment in the Alaska segment would be approximately (US) $525 million. The Company may adjust its partnership interest in the project once financing arrangements have been finalized. 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, planned completion of the Alaska segment has been deferred from 1987 to 1989. Accordingly, in the first quarter of 1982, the Company discontinued recording equity AFUDC.

In 1981 the Alaska segment partnership recorded in its natural gas transmission plant under construction and partnership equity accounts costs related to expenditures incurred previously by certain of the partners, including the Company, who were also co-sponsors of another project. The partnership subsequently applied to the FERC for approval of these costs as a proper rate base item in the Alaska segment. In 1982, the FERC ruled against inclusion. Accordingly, the Company has reduced the carrying value of its investment in the Alaska segment during 1982 by $14,750,000, with a corresponding reduction in a previously recorded deferred credit. This adjustment had no impact on reported earnings. In addition, the Company also reversed $2,478,000 of related AFUDC previously recorded in income against 1982 earnings.

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 1982 and 1981 financial information for the Alaska segment partnership stated in thousands of United States dollars:

	1982	1981
Natural gas transmission plant under construction	**513,431**	401,340
Deferred charges	**258**	—
Current liabilities less current assets	**(444)**	(1,584)
Other liabilities	**(63,480)**	(8,946)
Partners' equity	**449,765**	390,810

(c) Canadian Segment (Saskatchewan section)
The Company has a 44% interest in Foothills Pipe Lines (Sask.) Ltd. ("Foothills (Sask.)"), which constructed 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 following sets out summarized 1982 and 1981 financial information for Foothills (Sask.) in thousands of dollars:

	1982	1981
Natural gas transmission plant (net)	**326,582**	260,700
Current liabilities less current assets	**(18,933)**	1,400
Deferred amounts	**(2,274)**	800
Long-term debt	**(221,760)**	(195,000)
Shareholders' equity	**83,615**	67,900
Revenues	**14,811**	—
Expenses	**37,089**	—
AFUDC	**33,668**	—
Net income	**11,390**	—

Trans Québec & Maritimes Pipeline
Each of the Company and Nova, an Alberta Corporation, ("Nova") has a 50% interest in a partnership (the "TQM partnership") which is constructing and operating a natural gas transmission system (the "TQM Pipeline") from the vicinity of Montreal to major market areas east of Montreal. In February and December 1982 natural gas deliveries commenced at Boisbriand and Trois-Rivières, Québec respectively. The construction and operation of the TQM Pipeline is being carried out on behalf of the partnership by Trans Québec & Maritimes Pipeline Inc. ("TQM"), which is 50% owned by each of the partners.

The NEB has authorized TQM to operate on a cost-of-service basis which provides for recovery of operating and maintenance expenses, depreciation and a rate of return which permits the recovery of its cost of debt and 15.75% on common equity with no provision for income taxes. This interim decision is effective pending a decision by the NEB on a tariff hearing presently underway.

In July 1982 the TQM partnership entered into a bridge financing agreement with a Canadian chartered bank to finance up to 75% of the estimated construction costs of the TQM Pipeline system to Quebec City to a maximum of $400 million. As at December 31, 1982, the TQM partnership had borrowed $301 million. The Company and Nova are parties to this agreement as sponsors.

Under the terms of this agreement, the TQM partnership has agreed to maintain a certain capital structure, and if capital expenditures intended for inclusion in the rate base of TQM are disallowed by the NEB, the TQM partnership and the sponsors have agreed to make capital contributions to TQM sufficient to restore the capital structure, if required.

The TQM partnership applied a portion of the loan referred to previously to refund prior equity contributions made by each of the partners to the partnership up to July 1982. As a result, the Company's investment at the end of 1982 has decreased from the amount recorded at the end of 1981.

The following sets out summarized financial information for TQM in thousands of dollars:

	1982
Natural gas transmission plant (net)	**379,822**
Deferred charges	**10,919**
Current liabilities less current assets	**(20,159)**
Bank loan	**(266,000)**
Partners' equity	**104,582**
Revenues	**22,064**
Expenses	**19,260**
AFUDC	**21,278**
Income before income taxes	**24,082**

3. Investments — Oil and Gas
Details are set out below of the Company's investment in producing and non-producing oil and gas properties in thousands of dollars:

	1982		1981	
	Investment	Equity Earnings	Investment	Equity Earnings
Canadian Operations	**588,047**	**29,837**	630,778	20,781
United States Operations	**87,227**	**(1,336)**	56,819	—
Other Foreign Operations	**65,307**	**1,622**	—	—
	740,581	**30,123**	687,597	20,781

Canadian Operations

In December 1979 the Company acquired a 50% undivided interest in the oil and gas properties of Maligne Resources Limited ("Maligne"), a wholly owned subsidiary of Dow Chemical Canada, Inc. At the date of purchase, Maligne owned a 25% undivided interest in a portion of the onshore oil and gas properties of Dome Petroleum Limited ("Dome") under the terms of a 1974 agreement and had exercised, pursuant to that agreement, the right to participate in a like interest in other properties subsequently acquired by Dome.

In 1980 the Company acquired a 12½% interest from Dome in the producing and non-producing properties of Kaiser Petroleum Ltd., which were acquired by Dome earlier in the year.

The majority of the Canadian properties are located in the Province of Alberta and were held at December 31, 1982, by a partnership of the Company and Maligne for joint administration and control. Each company has rights and obligations under a participation agreement dated December 1, 1979, with Dome 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 March 1982 the Company acquired from Dome for approximately $560 million a 12½% undivided interest in substantially all of the assets of Hudson's Bay Oil & Gas Company Limited ("HBOG"). As a result of this purchase, the Company has significantly expanded its interests in oil and gas land holdings, both foreign and domestic, and acquired interests in domestic mining properties. Through the partnership, the Company arranged bank loans to cover the entire purchase price of this acquisition. 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, 1982 reflects the cost of this acquisition net of these non-recourse bank loans.

Included in the HBOG acquisition is a 12½% interest in certain mining properties including Cyprus Anvil Mining Corporation ("Cyprus") which was shut down in 1982. The Company uses the equity method of accounting for its investment in Cyprus. The ultimate realization of the Company's investment in Cyprus is dependent upon resumption of profitable operations which is itself dependent upon Cyprus obtaining satisfactory capital financing and upon improved mineral market conditions and general economic conditions. At December 31, 1982 the Company's total investment in mining properties amounted to $47,087,000.

As a result of the HBOG acquisition, the Company has an interest in oil and gas permits in the Beaufort region and the East Coast offshore area which are administered by the Company. Preliminary exploration activities are currently under way on these permits.

United States Operations

Effective August 1980 the Company entered into an agreement with Dome Petroleum Corp. ("Dome Corp."), a subsidiary of Dome, whereby the Company purchased an undivided 17⅓% interest in all non-producing oil and gas properties then held by Dome Corp. in the territorial United States. The Company has agreed, subject to certain conditions, to participate in a like interest in future acquisitions of Dome Corp.

Other Foreign Operations

The Company has interests in foreign oil and gas concessions acquired through the HBOG purchase, the most significant of which are located in Indonesia. In connection with Indonesian operations, the Company contributes its pro rata share of exploration and development expenditures to the operator of the concessions.

Detailed below is summarized financial information setting out the Company's proportionate share of oil and gas joint ventures in thousands of dollars:

	1982	1981
Oil and gas properties — at cost	**1,390,356**	712,773
Accumulated depreciation and depletion	**(50,126)**	(13,611)
Current liabilities less current assets	**(2,111)**	(11,565)
Long-term debt	**(597,538)**	—
Net investment	**740,581**	687,597
Net revenues	**189,617**	36,766
Operating expenses	**159,494**	15,985
Income from operations	**30,123**	20,781

In 1982 and 1981 interest was capitalized in connection with oil and gas properties in the approximate amount of $57,578,000 and $58,654,000 respectively.

4. Long-Term Debt

First Mortgage Pipe Line Bonds

The Deed of Trust and Mortgage securing the 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.

Sinking Fund 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 were amended in 1981 to 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.

Term Loans, Promissory Notes and Notes

Term loans, term promissory notes, notes payable in U.S. dollars and Swiss franc notes rank equally with the sinking fund debentures and prior to the subordinated debentures. These instruments contain various covenants which, in certain instances allow prepayments without bonus or penalty. 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 $41,288,000 for 1983, $64,862,000 for 1984, $85,397,000 for 1985, $313,751,000 for 1986 and $256,567,000 for 1987.

Based on the rates of exchange prevailing at December 31, 1982, $1,455,554,000 would be required to discharge the long-term portion of the foreign currency debt outstanding at December 31, 1982. Such long-term debt (excluding current maturities) is included in the Consolidated Schedule of Long-Term Debt in the amount of $1,440,332,000 at December 31, 1982.

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 1982, are set out in the table below:

	Authorized and Outstanding December 31, 1981		Issued for Cash		Purchase, Retraction and/or Conversion of Preferred Shares		Authorized and Outstanding December 31, 1982	
Issue	Shares	Value	Shares	Value	Shares	Value	Shares	Value
		($000)		($000)		($000)		($000)
First Preferred Shares								
Cumulative redeemable								
—$2.80	687,146	34,357			(26,800)	(1,340)	660,346	33,017
Cumulative redeemable retractable								
—$4.50 Series B	964,900	48,245			(20,060)	(1,003)	944,840	47,242
—Series C	300,000	15,000			(300,000)	(15,000)	—	—
—Series D	2,200,000	110,000					2,200,000	110,000
—Series E	1,500,000	75,000					1,500,000	75,000
—Series F	1,600,000	80,000					1,600,000	80,000
Second Preferred Shares								
Cumulative redeemable convertible								
—$2.65 Series A	38,701	1,935			(38,701)	(1,935)	—	—
		364,537		—		(19,278)		345,259
Common Shares	44,349,903	98,495	317,750	7,161	122,198	1,852	44,789,851	107,508
Capital Stock		463,032		7,161		(17,426)		452,767

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

Dividend Reinvestment, Stock Dividend and Share Purchase Plans

On December 1, 1982, TransCanada'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. Plan participants may also make cash payments of up to $3,000 per quarter for the purchase of additional common shares of the Company.

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. Plan participants may also make cash payments of up to $3,000 per quarter for the purchase of additional common shares of the Company.

Where a participant in either of the above referenced plans elects to make an optional cash payment, the common shares purchased will be issued at 100% of a specified average market price.

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.

The Company is required, for the $4.50 retractable first preferred shares, on each February 1 until 1984, to set aside on its books a purchase fund account equal to the lesser of $1,500,000 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.

Purchase funds for the series D, series E and series F preferred shares commence at the earliest in 1984.

These 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.

The Company, on May 31, 1982, redeemed and cancelled all of the $2.65 series A convertible second preferred shares outstanding at a price of $52.00 per share plus accrued and unpaid dividends. In addition, the Company, on September 15, 1982, retracted and cancelled all of the first preferred shares series C at a price of $50.00 per share plus accrued and unpaid dividends.

Preferred Share Dividend Rates and Retraction Dates

The table below sets out the current dividend rate of the retractable first preferred shares and the retraction dates:

Series	Current Dividend Rate	Retraction Dates
$4.50 Series B	$4.50	January 31, 1985
Series D	$5.00	November 1, 1983 and 1985
Series E	$5.16	November 1, 1984 and 1989
Series F	$7.18	May 1, 1984 and 1988

Common Shares Reserved

At December 31, 1982, 327,903 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 stock purchase plans.

Interest Free Loans

Interest free loans amounting to $18,566,000 at December 31, 1982, 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, 1982, under the most restrictive provisions, approximately $90,000,000 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.

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.

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.

The overpayments claimed to October 1980 amounted to $59,168,000 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

The Company, with respect to its utility operations, sells gas to and incurs charges for gas transmission services for its affiliate Great Lakes and has contracts for the purchase of gas and the extraction of gas by-products from Dome, a major shareholder.

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 including Great Lakes and Dome.

Reference should be made to Note 2 for details of a loan by the Company to Great Lakes.

Dome also renders management services in connection with production of oil and gas, the consideration for which is not material. Certain oil and gas property transactions with Dome are described in Note 3.

In addition, by agreement between the Company and Dome, Dome agreed, subject to the fulfillment of certain conditions, to convey to the Company its right to a 50% participation with Nova in new extraction facilities to be located at Empress, Alberta. These facilities are to be constructed and operated by Dome. It is contemplated that the Company may become a 50% investor on a cost-of-service basis in the new facilities, the total cost of which is currently estimated to be $200 million.

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

Income Taxes

As described in the Summary of Significant Accounting Policies, effective August 1, 1982, the Company adopted the taxes payable method of recording income taxes applicable to its current Canadian utility operations for ratemaking and accounting purposes as prescribed by the NEB. As this change has been prescribed by the NEB, it has not been applied retroactively.

PEAT MARWICK

Auditors' Report to the Shareholders

We have examined the statement of consolidated financial position of TransCanada PipeLines Limited as at December 31, 1982 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, 1982 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 income taxes described in Note 10, have been applied on a basis consistent with that of the preceding year.

Peat, Marwick, Mitchell & Co.

Toronto, Canada
February 2, 1983

Chartered Accountants

Directors and Officers

Directors

John M. Beddome, Chairman
TransCanada PipeLines and Group Vice-President, Exploration & Development
Dome Petroleum Limited, Calgary

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

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

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

John P. Gallagher, Chairman and Chief Executive Officer
Dome Petroleum Limited, Calgary

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

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

James W. Kerr, Consultant to the Company and Company Director
Toronto

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

Gordon P. Osler, Chairman
Stanton Pipes Limited, Toronto

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

Smiley Raborn, Jr.,
Petroleum Consultant, Calgary

William E. Richards, President
Dome Petroleum Limited, Calgary

Frank A. Schultz,
Independent Oil Operator, Dallas

George W. Woods, Vice-Chairman and Chief Operating Officer
TransCanada PipeLines, Toronto

Officers

John M. Beddome, Chairman

Radcliffe R. Latimer, President and Chief Executive Officer

Alberta Division

C. Kennedy Orr, Senior Vice-President, Alberta Division

Robert T. Liddle, Vice-President, Operations and Special Projects

Corporate Division

James M. Cameron, Executive Vice-President, Corporate

Lionel H. Pilon, Vice-President, Law

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

Finance Division

H. Neil Nichols, Senior Vice-President, Corporate Finance

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

Raymond F. Sim, Vice-President, Corporate Taxation

Oil and Gas Division

Gordon A. Leslie, Vice-President

Arthur A. Wilkins, Vice-President

Pipeline Division

George W. Woods, Vice-Chairman and Chief Operating Officer

George M. Hugh, Senior Vice-President, Engineering and Operations

Richard D. Walker, Senior Vice-President, Marketing and Administration

George C. Britton, Vice-President, Project Development

Bruce M. Escoffery, Vice-President, Marketing

Derek E. Henwood, Vice-President, Engineering and Operations

Robert J. Reid, Vice-President, Engineering and Operations

Robert S. Smith, Vice-President and Controller

Other

John K. Archambault, Vice-President

Donald M. Johnston, Corporate Secretary

TransCan Holdings Ltd.

A. Bercovici, President

1981	1980	1979	1978	1977	1976	1975	1974	1973
$2,082,199	$1,819,121	$1,634,089	$1,537,733	$1,254,204	$1,044,503	$ 686,744	$ 449,358	$ 341,690
1,261,546	1,267,923	920,994	633,894	597,440	438,454	214,423	111,897	88,692
61,152	36,013	25,889	21,586	18,681	16,180	19,222	6,687	6,421
3,404,897	3,123,057	2,580,972	2,193,213	1,870,325	1,499,137	920,389	567,942	436,803
2,502,670	2,446,058	1,990,442	1,703,472	1,447,720	1,108,613	601,013	316,691	227,269
485,171	390,912	338,318	300,962	279,844	255,592	191,526	147,304	130,157
2,987,841	2,836,970	2,328,760	2,004,434	1,727,564	1,364,205	792,539	463,995	357,426
417,056	286,087	252,212	188,779	142,761	134,932	127,850	103,947	79,377
28,445	9,894	10,350	7,975	9,411	8,329	6,670	6,098	6,022
20,781	6,104	333	—	—	—	—	—	—
49,226	15,998	10,683	7,975	9,411	8,329	6,670	6,098	6,022
19,950	5,802	2,890	2,750	6,520	6,604	2,211	5,013	12,071
229,671	123,173	90,025	74,905	72,509	70,230	70,434	69,476	57,958
256,561	184,714	175,760	124,599	86,183	79,635	66,297	45,582	39,512
102,489	82,254	81,750	29,500	—	—	—	—	—
154,072	102,460	94,010	95,099	86,183	79,635	66,297	45,582	39,512
—	—	—	—	—	—	—	—	12,461
154,072	102,460	94,010	95,099	86,183	79,635	66,297	45,582	51,973
28,499	9,025	6,842	7,173	7,860	10,456	13,863	12,119	11,508
$ 125,573	$ 93,435	$ 87,168	$ 87,926	$ 78,323	$ 69,179	$ 52,434	$ 33,463	$ 40,465
$ 2.85	$ 2.18	$ 2.16	$ 2.20	$ 2.01	$ 1.92	$ 1.65	$ 1.17	$ 1.01
$ 2.84	$ 2.18	$ 2.14	$ 2.18	$ 1.95	$ 1.79	$ 1.45	$ 1.03	$ .92
$ 1.16	$ 1.16	$ 1.16	$ 1.06¼	$ 0.97	$ 0.85¾	$ 0.69	$ .4833	$ .333
% 40.70	% 53.21	% 53.70	% 48.29	% 48.26	% 44.66	% 41.82	% 41.31	% 33.00
$ 275,742	$ 241,073	$ 202,505	$ 152,607	$ 138,267	$ 135,374	$ 107,992	$ 70,010	$ 47,375
$ 6.26	$ 5.64	$ 5.02	$ 3.82	$ 3.54	$ 3.75	$ 3.40	$ 2.44	$ 1.71
$2,465,107	$1,929,187	$1,811,490	$1,766,893	$1,720,910	$1,637,789	$1,588,754	$1,555,506	$1,449,925
1,920,338	1,438,918	1,366,863	1,363,922	1,362,640	1,322,662	1,315,545	1,314,992	1,240,782
2,458,772	1,706,772	1,384,731	917,026	822,299	809,701	819,797	820,075	861,335
1,164,144	966,763	694,817	650,540	605,623	567,971	535,762	508,391	440,180
799,607	718,111	604,212	555,734	501,779	446,411	317,755	276,903	228,462
18.03	16.33	14.88	13.85	12.71	11.67	9.93	8.91	8.20
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
44,349,903	43,968,977	40,593,244	40,111,044	39,487,613	38,248,159	32,005,509	31,077,790	27,859,257
44,059,414	42,762,762	40,369,023	39,931,361	39,028,618	36,117,610	31,746,810	28,687,701	27,781,065
23,907	26,187	26,058	28,655	27,341	25,454	24,244	24,302	24,984

Note: The above TEN-YEAR SUMMARY reflects a restatement of 1976 earnings increasing net income by $2,856,000. 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 1982" from Mr. Mitchell T. G. Graye, Vice-President and Treasurer, TransCanada PipeLines, P.O. Box 54, Commerce Court West, Toronto, Ontario, M5L 1C2.

Ten-Year Summary Years ended December 31

	1982
Income (in thousands of dollars)	
Revenues	
Gas sales—domestic	$ 2,382,709
—export	981,099
Gas transportation and other	103,107
	3,466,915
Costs and Expenses	
Cost of gas sold	2,425,425
Transmission, operating and general	551,994
	2,977,419
	489,496
Income from Investments	
Pipelines	52,909
Oil and gas	30,123
	83,032
Other Income (net)	61,220
Financial Charges (net)	368,310
Income before income taxes	265,438
Income Taxes — Current and Deferred	66,520
Net Income for the Year before Extraordinary Gain	198,918
Gain on sale of subsidiary	—
Net Income for the Year	198,918
Less provision for dividends on preferred shares	37,790
Net Income Applicable to Common Shares	$ 161,128
Net Income per Average Common Share	
Basic	$ 3.62
Fully diluted	$ 3.60
Dividends declared, per common share	$ 1.19
Dividend payout ratio, common shares	% 32.87
Funds provided from operations	$ 244,427
—per average common share	$ 5.49
Balance Sheet (in thousands of dollars)	
Plant, property and equipment—gross	$ 3,266,782
—net	2,650,784
Long-term debt	2,152,875
Shareholders' equity—total	1,262,745
—common	917,486
—per common share at year end	20.48
Statistics	
Kilometres of pipeline—including loopline	10 631
Compressor power—kilowatts	1 020 500
Gas delivered for sales and transportation (millions of cubic metres)	
—annual	32 497
—maximum day	125
Number of regular employees, December 31	1,798
Common shares outstanding—year end	44,789,851
—average	44,537,632
Number of shareholders, December 31	22,378

Executive Office

P.O. Box 54, Commerce Court West,
Toronto, Ontario, M5L 1C2
Telephone (416) 869-2111

Registered Office

407 Eighth Avenue S.W., Calgary,
Alberta, T2P 2M7
Telephone (403) 269-5611

Subsidiary Offices

TCPL Resources Ltd.
Suite 3700, 250-6th Avenue S.W.
Bow Valley Square IV
Calgary, Alberta, T2P 3H7
Telephone (403) 267-2410

TCPL Resources U.S.A. Ltd.
Suite 2170, Dome Tower
1625 Broadway Avenue
Denver, Colorado, 80202
Telephone (303) 825-7767

Cancarb Limited
P.O. Box 310
Medicine Hat, Alberta
T1A 7E4
Telephone (403) 527-1121

TCPL Nederland B.V.
Gebouw Hirsch
Leidseplein 29 1017 PS
Amsterdam, The Netherlands
Telephone 011-31-20-26-08-11

TCPL Investments AG
Baarerstrasse 110/B
CH-6300, Zug, Switzerland
Telephone 011-42-31-22-01

Subsidiaries (Wholly-Owned)

TransCan Holdings Ltd.
A company holding shares of subsidiaries carrying out non-regulated activities.

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 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. and TransCanada Border PipeLine 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 Great Lakes Limited
A company holding shares of Great Lakes Gas Transmission Company.

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 building pipeline facilities in Quebec, New Brunswick and Nova Scotia.

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
6¾% first mortgage pipe line bonds, National Trust Company, Limited, Montreal and Toronto.

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

Registrar U.S. Series
5⅝%, 6¼%, 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.

Sinking Fund Debentures

Trustee
Crown Trust Company, Toronto.

Registrar
10% series A, 9¾% series B, 9% series C, 8⅞% series D, 9% series E, 11½% series F, 9.60% series G and 18% series H sinking fund debentures. Crown 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.

Lowering pipe into trench on the North Bay Shortcut near Petawawa, Ontario

TRANSPORTING NATURAL GAS

FOR A QUARTER CENTURY

TransCanada PipeLines

Printed in Canada